

BAYTEX ENERGY CORP.

Management's Discussion and Analysis

For the three and six months ended June 30, 2021 and 2020

Dated July 28, 2021

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2021. This information is provided as of July 28, 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 and six months ended June 30, 2021 ("Q2/2021" and "YTD 2021") have been compared with the results for the three and six months ended June 30, 2020 ("Q2/2020" and "YTD 2020"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three and six months ended June 30, 2021, its audited comparative consolidated financial statements for the years ended December 31, 2020 and 2019, together with the accompanying notes, and its 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 energy 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.

SECOND QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results for Q2/2021 as the global economy continued to recover from the impact of the COVID-19 pandemic. The outlook for crude oil demand has improved with the increase in economic activity due to the distribution of vaccines and easing of restrictions. Oil prices were also supported by ongoing OPEC production curtailments and limited supply growth from large independent producers. As a result, the average WTI benchmark price for Q2/2021 was US\$66.07/bbl which was US\$38.22/bbl higher than Q2/2020 when WTI averaged US\$27.85/bbl. With higher commodity prices, we generated adjusted funds flow of \$175.9 million and free cash flow of \$112.5 million which contributed to a \$129.3 million reduction in net debt from Q1/2021. Strong well performance across all of our assets resulted in production of 81,162 boe/d which exceeded the high end of our previous annual guidance range of 77,000 - 79,000 boe/d. Our disciplined approach to capital allocation and continued focus on reducing our cost structure has improved the results we have achieved as commodity prices have increased.

Exploration and development expenditures of \$61.5 million for Q2/2021 were split between our Canadian and U.S. properties. Our U.S. production increased 7,216 boe/d from Q1/2021 as 38 (10.2 net) wells were brought on production in Q2/2021 compared to 24 (7.0 net) wells in Q1/2021. Due to spring break up, activity levels in Canada were lower in Q2/2021 resulting in 15 (15.0 net) wells brought on production compared to 51 (47.1 net) wells in Q1/2021. Lower activity levels resulted in production in Canada that was 4,834 boe/d lower than Q1/2021.

Adjusted funds flow was \$175.9 million in Q2/2021 which is higher than \$17.9 million reported for Q2/2020 and \$156.6 million for Q1/2021 as a result of higher benchmark prices along with higher production for Q2/2021 relative to Q2/2020 and Q1/2021. The increase in crude oil prices was the primary factor that resulted in a \$211.1 million increase in operating netback for Q2/2021 relative to Q2/2020. The increase in commodity prices also resulted in an impairment reversal for our oil and gas properties of \$1.1 billion for Q2/2021 which contributed to net income of \$1.1 billion compared to a net loss of \$0.1 billion for Q2/2020.

Net debt decreased \$218.0 million to \$1.63 billion at June 30, 2021 compared to \$1.85 billion at December 31, 2020. The reduction in net debt was primarily due to free cash flow of \$183.0 million being allocated to debt repayment combined with a \$35.0 million decrease in the reported amount of our U.S. dollar denominated net debt due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021.

During Q2/2021, we purchased and cancelled US\$5.8 million principal of the 5.625% Notes at a discount and recorded a gain of \$0.4 million. Subsequent to Q2/2021 we also used free cash flow generated in the first half of 2021 to repurchase and cancel US\$100.0 million principal amount of the 5.625% Notes due 2024 at the call price of 100.938%, plus accrued interest, effective July 28, 2021.

2021 GUIDANCE

The following table compares our revised 2021 annual guidance to our previously announced guidance. As a result of our strong operational performance through the first half of 2021 we are increasing our annual production guidance range to 79,000 - 80,000 boe/d while maintaining exploration and development expenditures guidance of \$285 - \$315 million.

Our interest expense guidance is 3% lower due to reduced net debt and the repurchase and cancellation of US\$105.8 million principal amount of the 5.625% Notes.

	Previous Annual Guidance ⁽¹⁾	Revised Annual Guidance
Exploration and development expenditures	\$285 - \$315 million	no change
Production (boe/d)	77,000 - 79,000	79,000 - 80,000
Expenses:		
Royalty rate	18.0% - 18.5%	no change
Operating	\$11.25 - \$12.00/boe	no change
Transportation	\$1.15 - \$1.25/boe	no change
General and administrative	\$42 million (\$1.48/boe)	\$42 million (\$1.45/boe)
Interest	\$98 million (\$3.46/boe)	\$95 million (\$3.27/boe)
Leasing expenditures	\$4 million	no change
Asset retirement obligations	\$6 million	no change

(1) As announced on April 29, 2021.

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

Three Months Ended June 30

	2021			2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	15,661	21,473	37,134	18,762	20,189	38,951
Heavy oil	21,269	—	21,269	11,832	—	11,832
Natural Gas Liquids (NGL)	1,779	5,784	7,563	933	6,701	7,634
Total liquids (bbl/d)	38,709	27,257	65,966	31,527	26,890	58,417
Natural gas (mcf/d)	50,974	40,198	91,172	36,982	47,564	84,546
Total production (boe/d)	47,205	33,957	81,162	37,691	34,817	72,508
Production Mix						
Segment as a percent of total	58 %	42 %	100 %	52 %	48 %	100 %
Light oil and condensate	33 %	63 %	46 %	50 %	58 %	54 %
Heavy oil	45 %	— %	26 %	31 %	— %	16 %
NGL	4 %	17 %	9 %	2 %	19 %	11 %
Natural gas	18 %	20 %	19 %	17 %	23 %	19 %

Six Months Ended June 30

	2021			2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	17,434	18,852	36,286	21,501	20,832	42,333
Heavy oil	21,627	—	21,627	20,343	—	20,343
Natural Gas Liquids (NGL)	1,874	5,030	6,904	1,125	6,603	7,728
Total liquids (bbl/d)	40,935	23,882	64,817	42,969	27,435	70,404
Natural gas (mcf/d)	52,036	38,921	90,957	42,041	48,410	90,451
Total production (boe/d)	49,609	30,369	79,978	49,976	35,503	85,479
Production Mix						
Segment as a percent of total	62 %	38 %	100 %	58 %	42 %	100 %
Light oil and condensate	35 %	62 %	45 %	43 %	59 %	50 %
Heavy oil	44 %	— %	27 %	41 %	— %	24 %
NGL	4 %	17 %	9 %	2 %	19 %	9 %
Natural gas	17 %	21 %	19 %	14 %	22 %	17 %

Production was 81,162 boe/d for Q2/2021 and 79,978 boe/d for YTD 2021 compared to 72,508 boe/d for Q2/2020 and 85,479 boe/d for YTD 2020. Total production was higher in Q2/2021 compared to Q2/2020 after we restored production that was shut-in during Q2/2020 and restarted development activity late in 2020. We have continued our development in Canada and the U.S. during 2021 following the reset of our business in 2020 which, along with strong well performance, resulted in production of 81,162 boe/d for Q2/2021. Total production of 79,978 boe/d for YTD 2021 is at the high end of our revised annual guidance of 79,000 - 80,000 and reflects the strong well performance in the U.S. and Canada YTD.

In Canada, production of 47,205 boe/d for Q2/2021 was higher than Q2/2020 production of 37,691 boe/d as our 2020 production was impacted by the suspension of our capital development program combined with shut-in production due to the sharp decline in oil prices in 2020. We restored shut-in production and restarted development activity as crude oil prices strengthened during the second half of 2020. With continued development activity and strong well performance, production averaged 49,609 boe/d for YTD 2021, consistent with production of 49,976 boe/d for YTD 2020 which reflects a higher level of activity in Q1/2020 before we shut-in production during Q2/2020.

In the U.S., production was 33,957 boe/d for Q2/2021 and 30,369 boe/d for YTD 2021 compared to 34,817 boe/d for Q2/2020 and 35,503 boe/d for YTD 2020. Production was lower in 2021 due to limited development activity during 2020 along with the impact of the Texas storm that disrupted operations in February 2021. We initiated production from 38 (10.2 net) wells during Q2/2021 and 62 (17.2 net) wells during YTD 2021 compared to 17 (4.6 net) wells during Q2/2020 and 47 (10.7 net) wells during YTD 2020.

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 continued to strengthen during Q2/2021 as the outlook for oil demand improved due to increasing global economic activity while OPEC has maintained production curtailments that have limited supply as economies recover and slowly reopen. These factors resulted in the WTI benchmark price averaging US\$66.07/bbl for Q2/2021 and US\$61.96/bbl for YTD 2021 which was higher relative to Q2/2020 and YTD 2020 when WTI averaged US\$27.85/bbl and US\$37.01/bbl, respectively.

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\$67.15/bbl during Q2/2021 and US\$63.26/bbl during YTD 2021 which is higher than US\$26.40/bbl during Q2/2020 and US\$37.97/bbl during YTD 2020. The MEH benchmark was at a US\$1.08/bbl premium to WTI in Q2/2021 and a US\$1.30/bbl premium in YTD 2021 compared to a US\$1.45/bbl discount to WTI during Q2/2020 and US\$0.96/bbl premium during YTD 2020.

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 narrower in Q2/2021 and YTD 2021 relative to Q2/2020 and YTD 2020 as a result of stronger demand for Canadian oil production along with lower light and heavy oil supply to North American markets during 2021.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price while pricing for our heavy oil production is based on the WCS benchmark price. The Edmonton par price averaged \$77.28/bbl during Q2/2021 and \$71.93/bbl during YTD 2021 compared to \$29.85/bbl during Q2/2020 and \$40.64/bbl during YTD 2020. Edmonton par traded at a discount to WTI of US\$3.13/bbl for Q2/2021 and US\$4.28/bbl for YTD 2021 compared to a discount of US\$6.31/bbl for Q2/2020 and US\$7.24/bbl for YTD 2020. The WCS heavy oil price for Q2/2021 and YTD 2021 averaged \$67.03/bbl and \$62.33/bbl, respectively, compared to \$22.70/bbl and \$28.68/bbl for the same periods of 2020. The WCS heavy oil differential was US\$11.48/bbl in Q2/2021 and US\$11.98/bbl in YTD 2021 compared to US\$11.47/bbl for Q2/2020 and US\$16.00/bbl for YTD 2020.

Natural Gas

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\$2.83/mmbtu for Q2/2021 and US\$2.76/mmbtu for YTD 2021 which is higher than US\$1.72/mmbtu for Q2/2020 and US\$1.83/mmbtu for YTD 2020. Lower U.S. natural gas production and increased demand along with the impact of the Texas winter storm in February 2021 resulted in higher natural gas prices in YTD 2021 relative to YTD 2020.

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 increasing supply and limited market access for Canadian natural gas production. The AECO benchmark averaged \$2.85/mcf during Q2/2021 and \$2.89/mcf during YTD 2021 which is higher than \$1.91/mcf for Q2/2020 and \$2.03/mcf for YTD 2020.

The following tables compare select benchmark prices and our average realized selling prices for the three and six months ended June 30, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
	2021	2020	Change	2021	2020	Change
Benchmark Averages						
WTI oil (US\$/bbl) ⁽¹⁾	66.07	27.85	38.22	61.96	37.01	24.95
MEH oil (US\$/bbl) ⁽²⁾	67.15	26.40	40.75	63.26	37.97	25.29
MEH oil differential to WTI (US\$/bbl)	1.08	(1.45)	2.53	1.30	0.96	0.34
Edmonton par oil (\$/bbl) ⁽³⁾	77.28	29.85	47.43	71.93	40.64	31.29
Edmonton par oil differential to WTI (US\$/bbl)	(3.13)	(6.31)	3.18	(4.28)	(7.24)	2.96
WCS heavy oil (\$/bbl) ⁽⁴⁾	67.03	22.70	44.33	62.33	28.68	33.65
WCS heavy oil differential to WTI (US\$/bbl)	(11.48)	(11.47)	(0.01)	(11.98)	(16.00)	4.02
AECO natural gas price (\$/mcf) ⁽⁵⁾	2.85	1.91	0.94	2.89	2.03	0.86
NYMEX natural gas price (US\$/mmbtu) ⁽⁶⁾	2.83	1.72	1.11	2.76	1.83	0.93
CAD/USD average exchange rate	1.2279	1.3860	(0.1581)	1.2471	1.3653	(0.1182)

(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.

	Three Months Ended June 30					
	2021			2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate (\$/bbl)	\$ 74.57	\$ 81.06	\$ 78.32	\$ 24.73	\$ 33.23	\$ 29.14
Heavy oil (\$/bbl) ⁽¹⁾	56.74	—	56.74	17.22	—	17.22
NGL (\$/bbl)	23.38	31.91	29.90	9.98	13.18	12.79
Natural gas (\$/mcf)	3.05	3.59	3.29	1.86	2.38	2.15
Weighted average (\$/boe) ⁽¹⁾	\$ 54.49	\$ 60.95	\$ 57.19	\$ 19.79	\$ 25.05	\$ 22.31

	Six Months Ended June 30					
	2021			2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate (\$/bbl)	\$ 69.02	\$ 77.36	\$ 73.36	\$ 38.67	\$ 48.05	\$ 43.29
Heavy oil (\$/bbl) ⁽¹⁾	51.53	—	51.53	19.72	—	19.72
NGL (\$/bbl)	24.02	32.88	30.48	10.72	14.04	13.56
Natural gas (\$/mcf)	3.04	5.63	4.15	1.94	2.50	2.24
Weighted average (\$/boe) ⁽¹⁾	\$ 50.82	\$ 60.69	\$ 54.57	\$ 26.53	\$ 34.22	\$ 29.73

(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 \$57.19/boe for Q2/2021 and \$54.57/boe for YTD 2021 compared to \$22.31/boe for Q2/2020 and \$29.73/boe for YTD 2020. In Canada, our realized price of \$54.49/boe for Q2/2021 was \$34.70/boe higher than \$19.79/boe for Q2/2020. Our realized price in the U.S. was \$60.95/boe in Q2/2021 which is \$35.90/boe higher than \$25.05/boe in Q2/2020. The increase in our realized price in Canada and the U.S. for Q2/2021 and YTD 2021 was a result of higher North American benchmark prices relative to the same periods of 2020.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price was \$74.57/bbl for Q2/2021 and \$69.02/bbl for YTD 2021 compared to \$24.73/bbl for Q2/2020 and \$38.67/bbl for YTD 2020. Our realized light oil and condensate price for Q2/2021 and YTD 2021 increased with the improvement in the benchmark price and represents discounts of \$2.71/bbl and \$2.91/bbl, respectively, to the Edmonton par price which is in line with expectations. Our realized light oil and condensate price was impacted by certain fixed price physical delivery contracts during Q2/2020 which resulted in a discount to the Edmonton par price of \$5.12/bbl for Q2/2020 and \$1.97/bbl for YTD 2020.

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 \$81.06/bbl for Q2/2021 and \$77.36/bbl for YTD 2021 compared to \$33.23/bbl for Q2/2020 and \$48.05/bbl for YTD 2020. Expressed in U.S. dollars, our realized light oil and condensate price of US\$66.02/bbl for Q2/2021 and US\$62.03/bbl for YTD 2021 represents discounts to MEH of US\$1.13/bbl and US\$1.23/bbl, respectively, which are narrower than a discount of US\$2.42/bbl for Q2/2020 and US\$2.78/bbl for YTD 2020. Narrower discounts to MEH reflects stronger price realizations on our marketing contracts in place during 2021.

Our realized heavy oil price, net of blending and other expense averaged \$56.74/bbl in Q2/2021 and \$51.53/bbl in YTD 2021 compared to \$17.22/bbl in Q2/2020 and \$19.72/bbl in YTD 2020. Our realized heavy oil price for Q2/2021 and YTD 2021 was \$39.52/bbl and \$31.81/bbl higher relative to Q2/2020 and YTD 2020, respectively, which is slightly less than a \$44.33/bbl and \$33.65/bbl increase in the WCS benchmark price over the same periods as we have certain fixed price delivery contracts that limit our exposure to the changes in WCS pricing.

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 for the underlying products. Our realized NGL price was \$29.90/bbl in Q2/2021 or 37% of WTI (expressed in Canadian dollars) compared to \$12.79/bbl or 33% of WTI (expressed in Canadian dollars) in Q2/2020. Our realized NGL price was \$30.48/bbl in YTD 2021 or 39% of WTI (expressed in Canadian dollars) compared to \$13.56/bbl or 27% of WTI (expressed in Canadian dollars) in YTD 2020.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was \$3.05/mcf for Q2/2021 and \$3.04/mcf for YTD 2021 compared to \$1.86/mcf in Q2/2020 and \$1.94/mcf for YTD 2020 and was relatively consistent with the AECO benchmark price in both periods. In the U.S., our realized natural gas price was US\$2.92/mcf for Q2/2021 and US\$4.51/mcf for YTD 2021 compared to US\$1.72/mcf for Q2/2020 and US\$1.83/mcf for YTD 2020. A portion of our natural gas production is based on the NYMEX daily index which resulted in a US\$1.75/mcf premium to the NYMEX monthly benchmark for YTD 2021 due to the fluctuations in the daily index caused by the winter storm in Texas during February 2021.

Petroleum and Natural Gas Sales

Three Months Ended June 30

	2021			2020		
(\$ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil sales						
Light oil and condensate	\$ 106,269	\$ 158,390	\$ 264,659	\$ 42,231	\$ 61,043	\$ 103,274
Heavy oil	129,782	—	129,782	24,003	—	24,003
NGL	3,786	16,796	20,582	847	8,035	8,882
Total oil sales	239,837	175,186	415,023	67,081	69,078	136,159
Natural gas sales	14,189	13,142	27,331	6,244	10,286	16,530
Total petroleum and natural gas sales	254,026	188,328	442,354	73,325	79,364	152,689
Blending and other expense	(19,967)	—	(19,967)	(5,460)	—	(5,460)
Total sales, net of blending and other expense	\$ 234,059	\$ 188,328	\$ 422,387	\$ 67,865	\$ 79,364	\$ 147,229

Six Months Ended June 30

	2021			2020		
(\$ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Oil sales						
Light oil and condensate	\$ 217,814	\$ 263,986	\$ 481,800	\$ 151,314	\$ 182,198	\$ 333,512
Heavy oil	238,820	—	238,820	99,846	—	99,846
NGL	8,150	29,939	38,089	2,196	16,877	19,073
Total oil sales	464,784	293,925	758,709	253,356	199,075	452,431
Natural gas sales	28,664	39,683	68,347	14,813	22,059	36,872
Total petroleum and natural gas sales	493,448	333,608	827,056	268,169	221,134	489,303
Blending and other expense	(37,087)	—	(37,087)	(26,817)	—	(26,817)
Total sales, net of blending and other expense	\$ 456,361	\$ 333,608	\$ 789,969	\$ 241,352	\$ 221,134	\$ 462,486

Total sales, net of blending and other expense, of \$422.4 million for Q2/2021 increased \$275.2 million from \$147.2 million reported for Q2/2020 while total sales, net of blending and other expense, of \$790.0 million for YTD 2021 increased \$327.5 million from \$462.5 million reported for YTD 2020. The increase in total sales in both periods is a result of higher realized pricing due to the increase in benchmark pricing.

In Canada, total sales, net of blending and other expense, was \$234.1 million for Q2/2021 which is an increase of \$166.2 million from \$67.9 million reported for Q2/2020. Total petroleum and natural gas sales increased due to higher realized pricing and higher production for Q2/2021 relative to Q2/2020. Our increased realized price resulted in a \$149.1 million increase in total sales, net of blending and other expense, while increased production resulted in a \$17.1 million increase in total sales, net of blending and other expense, relative to Q2/2020. Despite lower production, the increase in benchmark prices resulted in our total sales, net of blending and other expense, increasing to \$456.4 million in YTD 2021 from \$241.4 million in YTD 2020.

In the U.S., petroleum and natural gas sales were \$188.3 million for Q2/2021 which is an increase of \$109.0 million from \$79.4 million reported for Q2/2020. Total petroleum and natural gas sales increased \$110.9 million due to higher realized pricing for Q2/2021 relative to Q2/2020 while lower production resulted in a \$2.0 million decrease in total sales, net of blending and other expense relative to Q2/2020. Higher realized pricing in YTD 2021 resulted in petroleum and natural gas sales of \$333.6 million which was \$112.5 million higher than \$221.1 million in YTD 2020 despite lower production in YTD 2021 relative to YTD 2020.

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 three and six months ended June 30, 2021 and 2020.

Three Months Ended June 30						
	2021			2020		
(\$ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	\$ 26,193	\$ 55,338	\$ 81,531	\$ 6,157	\$ 22,999	\$ 29,156
Average royalty rate ⁽¹⁾	11.2 %	29.4 %	19.3 %	9.1 %	29.0 %	19.8 %
Royalties per boe	\$ 6.10	\$ 17.91	\$ 11.04	\$ 1.80	\$ 7.26	\$ 4.42

Six Months Ended June 30						
	2021			2020		
(\$ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	\$ 50,857	\$ 97,624	\$ 148,481	\$ 21,675	\$ 64,201	\$ 85,876
Average royalty rate ⁽¹⁾	11.1 %	29.3 %	18.8 %	9.0 %	29.0 %	18.6 %
Royalties per boe	\$ 5.66	\$ 17.76	\$ 10.26	\$ 2.38	\$ 9.94	\$ 5.52

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

Royalties for Q2/2021 were \$81.5 million or 19.3% of total sales, net of blending and other expense compared to \$29.2 million or 19.8% for Q2/2020. Total royalties for YTD 2021 were \$148.5 million or 18.8% of total sales, net of blending and other expense, compared to \$85.9 million or 18.6% for YTD 2020. Total royalty expense was higher for Q2/2021 and YTD 2021 due to higher total sales, net of blending and other expense, relative to the same periods of 2020. Our royalty rates of 19.3% for Q2/2021 and 18.8% for YTD 2021 were consistent with 19.8% for Q2/2020 and 18.6% for YTD 2020. Our average royalty rate of 18.8% for YTD 2021 is consistent with expectations and is slightly above our annual guidance range of 18.0% - 18.5% for 2021 due to higher than expected benchmark commodity prices and strong realized pricing in Canada.

Our Canadian royalty rates of 11.2% for Q2/2021 and 11.1% for YTD 2021 were higher than 9.1% for Q2/2020 and 9.0% for YTD 2020 due to higher benchmark commodity prices which resulted in a higher royalty rate on our Canadian properties in 2021 relative to 2020. In the U.S., royalties averaged 29.4% and 29.3% of total sales for Q2/2021 and YTD 2021, respectively, which is consistent with 29.0% for the same periods of 2020 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Operating Expense

Three Months Ended June 30

	2021			2020		
(\$ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Operating expense	\$ 61,793	\$ 21,108	\$ 82,901	\$ 49,162	\$ 24,518	\$ 73,680
Operating expense per boe	\$ 14.39	\$ 6.83	\$ 11.22	\$ 14.33	\$ 7.74	\$ 11.17

Six Months Ended June 30

	2021			2020		
(\$ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Operating expense	\$ 123,154	\$ 40,295	\$ 163,449	\$ 128,084	\$ 50,066	\$ 178,150
Operating expense per boe	\$ 13.72	\$ 7.33	\$ 11.29	\$ 14.08	\$ 7.75	\$ 11.45

Total operating expense was \$82.9 million (\$11.22/boe) for Q2/2021 and \$163.4 million (\$11.29/boe) for YTD 2021 compared to \$73.7 million (\$11.17/boe) for Q2/2020 and \$178.2 million (\$11.45/boe) for YTD 2020. Total operating expense for Q2/2021 increased with production relative to Q2/2020 while total operating expense for YTD 2021 decreased with production relative to YTD 2020. Operating expense of \$11.29/boe for YTD 2021 is consistent with expectations and our revised annual guidance range of \$11.25 - \$12.00/boe.

In Canada, operating expense was \$61.8 million (\$14.39/boe) for Q2/2021 and \$123.2 million (\$13.72/boe) for YTD 2021 compared to \$49.2 million (\$14.33/boe) for Q2/2020 and \$128.1 million (\$14.08/boe) for YTD 2020. Operating expense in Canada for Q2/2021 has increased with higher production relative to Q2/2020 while operating expense for YTD 2021 decreased with lower production relative to YTD 2020. Per unit operating expense of \$14.39/boe for Q2/2021 and \$13.72/boe for YTD 2021 was relatively consistent with \$14.33/boe for Q2/2020 and \$14.08/boe for YTD 2020.

U.S. operating expense was \$21.1 million (\$6.83/boe) for Q2/2021 and \$40.3 million (\$7.33/boe) for YTD 2021 compared to \$24.5 million (\$7.74/boe) for Q2/2020 and \$50.1 million (\$7.75/boe) for YTD 2020. Lower operating expense is primarily a result of lower U.S. production in Q2/2021 and YTD 2021 relative to Q2/2020 and YTD 2020. Expressed in U.S. dollars, per unit operating expense was US\$5.56/boe in Q2/2021 and US\$5.88/boe for YTD 2021 which was relatively consistent with US\$5.58/boe for Q2/2020 and US\$5.68/boe for YTD 2020.

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 three and six months ended June 30, 2021 and 2020.

Three Months Ended June 30

	2021			2020		
(\$ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Transportation expense	\$ 7,486	\$ —	\$ 7,486	\$ 5,031	\$ —	\$ 5,031
Transportation expense per boe	\$ 1.74	\$ —	\$ 1.01	\$ 1.47	\$ —	\$ 0.76

Six Months Ended June 30

	2021			2020		
(\$ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Transportation expense	\$ 16,274	\$ —	\$ 16,274	\$ 15,373	\$ —	\$ 15,373
Transportation expense per boe	\$ 1.81	\$ —	\$ 1.12	\$ 1.69	\$ —	\$ 0.99

Transportation expense was \$7.5 million (\$1.01/boe) for Q2/2021 and \$16.3 million (\$1.12/boe) for YTD 2021 compared to \$5.0 million (\$0.76/boe) for Q2/2020 and \$15.4 million (\$0.99/boe) for YTD 2020. The increase in total transportation expense in both periods of 2021 relative to 2020 is the result of higher production in Canada. Per unit transportation expense in Canada of \$1.74/boe for Q2/2021 and \$1.81/boe for YTD 2021 is higher than \$1.47/boe for Q2/2020 and \$1.69/boe for YTD 2020 due to additional heavy oil production in both periods of 2021 relative to 2020. Per unit transportation expense of \$1.12/boe for YTD 2021 is consistent with expectations and was slightly below our revised annual guidance of \$1.15 - \$1.25/boe.

Blending and Other Expense

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

Blending and other expense was \$20.0 million for Q2/2021 and \$37.1 million for YTD 2021 compared to \$5.5 million for Q2/2020 and \$26.8 million for YTD 2020. Higher blending and other expense reflects higher heavy oil sales along with an increase in the cost of blending diluent in 2021 relative to 2020.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. 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 three and six months ended June 30, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
(\$ thousands)	2021	2020	Change	2021	2020	Change
Realized financial derivatives gain (loss)						
Crude oil	\$ (38,234)	\$ 13,524	\$ (51,758)	\$ (58,275)	\$ 40,169	\$ (98,444)
Natural gas	(790)	378	(1,168)	(1,517)	589	(2,106)
Interest and financing	—	(278)	278	—	(284)	284
Total	\$ (39,024)	\$ 13,624	\$ (52,648)	\$ (59,792)	\$ 40,474	\$ (100,266)
Unrealized financial derivatives gain (loss)						
Crude oil	\$ (81,069)	\$ (71,936)	\$ (9,133)	\$ (166,539)	\$ 27,873	\$ (194,412)
Natural gas	(7,898)	1,181	(9,079)	(9,285)	1,059	(10,344)
Interest and financing	—	204	(204)	—	(474)	474
Equity total return swap ("Equity TRS")	4,484	1,265	3,219	5,357	(1,749)	7,106
Total	\$ (84,483)	\$ (69,286)	\$ (15,197)	\$ (170,467)	\$ 26,709	\$ (197,176)
Total financial derivatives gain (loss)						
Crude oil	\$ (119,303)	\$ (58,412)	\$ (60,891)	\$ (224,814)	\$ 68,042	\$ (292,856)
Natural gas	(8,688)	1,559	(10,247)	(10,802)	1,648	(12,450)
Interest and financing	—	(74)	74	—	(758)	758
Equity TRS	4,484	1,265	3,219	5,357	(1,749)	7,106
Total	\$ (123,507)	\$ (55,662)	\$ (67,845)	\$ (230,259)	\$ 67,183	\$ (297,442)

We recorded total financial derivative losses of \$123.5 million for Q2/2021 and \$230.3 million for YTD 2021 compared to a loss of \$55.7 million for Q2/2020 and a gain of \$67.2 million for YTD 2020. Realized financial derivatives losses of \$39.0 million for Q2/2021 and \$59.8 million for YTD 2021 were primarily a result of the market prices for crude oil settling at levels above those set in our derivative contracts. Unrealized losses of \$84.5 million for Q2/2021 and \$170.5 million for YTD 2021 were primarily a result of the increase in forecasted crude oil pricing used to revalue our crude oil contracts in place at June 30, 2021 relative to December 31, 2020 along with the valuation of new contracts entered during the period. The fair value of our financial derivative contracts resulted in a net liability of \$192.2 million at June 30, 2021 compared to a net liability of \$21.7 million at December 31, 2020.

We had the following commodity financial derivative contracts as at July 28, 2021.

	Period	Volume	Price/Unit ⁽¹⁾	Index
Oil				
Basis Swap	Jul 2021 to Dec 2021	8,000 bbl/d	WTI less US\$13.41/bbl	WCS
Basis Swap	Jan 2022 to Dec 2022	9,000 bbl/d	WTI less US\$12.47/bbl	WCS
Basis Swap ⁽⁴⁾	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US\$13.00/bbl	WCS
Basis Swap	Jul 2021 to Dec 2021	7,500 bbl/d	WTI less US\$5.03/bbl	MSW
Basis Swap	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US\$4.75/bbl	MSW
Basis Swap ⁽⁴⁾	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US\$4.50/bbl	MSW
Fixed Sell	Jul 2021 to Dec 2021	4,000 bbl/d	US\$45.00/bbl	WTI
3-way option ⁽²⁾	Jul 2021 to Dec 2021	500 bbl/d	US\$35.00/US\$45.00/US\$49.03	WTI
3-way option ⁽²⁾	Jul 2021 to Dec 2021	1,500 bbl/d	US\$35.00/US\$45.00/US\$49.10	WTI
3-way option ⁽²⁾	Jul 2021 to Dec 2021	3,500 bbl/d	US\$35.00/US\$45.00/US\$49.50	WTI
3-way option ⁽²⁾	Jul 2021 to Dec 2021	10,000 bbl/d	US\$35.00/US\$45.00/US\$55.00	WTI
3-way option ⁽²⁾	Jul 2021 to Dec 2021	2,000 bbl/d	US\$37.00/US\$42.50/US\$48.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	1,500 bbl/d	US\$40.00/US\$50.00/US\$58.10	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,000 bbl/d	US\$46.00/US\$56.00/US\$66.72	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 bbl/d	US\$47.00/US\$57.00/US\$67.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 bbl/d	US\$50.00/US\$60.00/US\$70.00	WTI
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,000 bbl/d	US\$53.00/US\$63.50/US\$72.90	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	Jul 2021 to Dec 2021	16,000 GJ/d	\$2.36/GJ	AECO 7A
Fixed Sell	Jan 2022 to Dec 2022	5,000 GJ/d	\$2.53/GJ	AECO 7A
Fixed Sell	Jul 2021 to Dec 2021	2,500 GJ/d	\$2.40/GJ	AECO 5A
Fixed Sell	Jan 2022 to Dec 2022	6,250 GJ/d	\$2.59/GJ	AECO 5A
Fixed Sell ⁽⁴⁾	Jan 2022 to Dec 2022	6,000 GJ/d	\$2.95/GJ	AECO 5A
Fixed Sell	Jul 2021 to Dec 2021	12,000 mmbtu/d	US\$2.70/mmbtu	NYMEX
Fixed Sell	Jan 2022 to Dec 2022	1,000 mmbtu/d	US\$2.94/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⁾	Jan 2022 to Dec 2022	1,500 mmbtu/d	US\$2.60/US\$2.91/US\$3.56	NYMEX
3-way option ⁽²⁾	Jan 2022 to Dec 2022	2,500 mmbtu/d	US\$2.60/US\$3.00/US\$3.83	NYMEX
3-way option ⁽²⁾	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\$50.00/US\$60.00/US\$70.00 contract, Baytex receives WTI plus US\$10.00/bbl when WTI is at or below US\$50.00/bbl; Baytex receives US\$60.00/bbl when WTI is between US\$50.00/bbl and US\$60.00/bbl; Baytex receives the market price when WTI is between US\$60.00/bbl and US\$70.00/bbl; and Baytex receives US\$70.00/bbl when WTI is above US\$70.00/bbl.

(3) 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 June 30, 2021.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and six months ended June 30, 2021 and 2020.

Three Months Ended June 30						
	2021			2020		
(\$ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Total production (boe/d)	47,205	33,957	81,162	37,691	34,817	72,508
Operating netback:						
Total sales, net of blending and other expense	\$ 54.49	\$ 60.95	\$ 57.19	\$ 19.79	\$ 25.05	\$ 22.31
Less:						
Royalties	(6.10)	(17.91)	(11.04)	(1.80)	(7.26)	(4.42)
Operating expense	(14.39)	(6.83)	(11.22)	(14.33)	(7.74)	(11.17)
Transportation expense	(1.74)	—	(1.01)	(1.47)	—	(0.76)
Operating netback	\$ 32.26	\$ 36.21	\$ 33.92	\$ 2.19	\$ 10.05	\$ 5.96
Realized financial derivatives (loss) gain	—	—	(5.28)	—	—	2.06
Operating netback after financial derivatives	\$ 32.26	\$ 36.21	\$ 28.64	\$ 2.19	\$ 10.05	\$ 8.02

Six Months Ended June 30						
	2021			2020		
(\$ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Total production (boe/d)	49,609	30,369	79,978	49,976	35,503	85,479
Operating netback:						
Total sales, net of blending and other expense	\$ 50.82	\$ 60.69	\$ 54.57	\$ 26.53	\$ 34.22	\$ 29.73
Less:						
Royalties	(5.66)	(17.76)	(10.26)	(2.38)	(9.94)	(5.52)
Operating expense	(13.72)	(7.33)	(11.29)	(14.08)	(7.75)	(11.45)
Transportation expense	(1.81)	—	(1.12)	(1.69)	—	(0.99)
Operating netback	\$ 29.63	\$ 35.60	\$ 31.90	\$ 8.38	\$ 16.53	\$ 11.77
Realized financial derivatives (loss) gain	—	—	(4.13)	—	—	2.60
Operating netback after financial derivatives	\$ 29.63	\$ 35.60	\$ 27.77	\$ 8.38	\$ 16.53	\$ 14.37

Our operating netback of \$33.92/boe for Q2/2021 and \$31.90/boe for YTD 2021 was higher than \$5.96/boe for Q2/2020 and \$11.77/boe for YTD 2020 due to the increase in benchmark pricing in Canada and the U.S. which resulted in higher per unit sales net of royalties. Total operating and transportation expense of \$12.23/boe for Q2/2021 and \$12.41/boe for YTD 2021 was consistent with \$11.93/boe for Q2/2020 and \$12.44/boe for YTD 2020. Including realized gains and losses on financial derivatives our operating netback was \$28.64/boe for Q2/2021 and \$27.77/boe for YTD 2021 compared to \$8.02/boe for Q2/2020 and \$14.37/boe for YTD 2020.

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 three and six months ended June 30, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
(\$ thousands except for per boe)	2021	2020	Change	2021	2020	Change
Gross general and administrative expense	\$ 11,158	\$ 7,476	\$ 3,682	\$ 20,619	\$ 19,364	\$ 1,255
Overhead recoveries	(548)	(38)	(510)	(1,276)	(2,151)	875
General and administrative expense	\$ 10,610	\$ 7,438	\$ 3,172	\$ 19,343	\$ 17,213	\$ 2,130
General and administrative expense per boe	\$ 1.44	\$ 1.13	\$ 0.31	\$ 1.34	\$ 1.11	\$ 0.23

G&A expense was \$10.6 million (\$1.44/boe) for Q2/2021 and \$19.3 million (\$1.34/boe) for YTD 2021 compared to \$7.4 million (\$1.13/boe) for Q2/2020 and \$17.2 million (\$1.11/boe) for YTD 2020. G&A expense for Q2/2021 and YTD 2021 was higher relative to the same periods of 2020 as employee and director compensation was reduced from Q2/2020 to Q4/2020 and the Company received benefits under the Canadian Emergency Wage Subsidy program in 2020.

G&A expense of \$1.34/boe is consistent with expectations and is slightly below our revised annual guidance of \$1.45/boe for 2021.

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 three and six months ended June 30, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
(\$ thousands except for per boe)	2021	2020	Change	2021	2020	Change
Interest on credit facilities	\$ 3,250	\$ 4,248	\$ (998)	\$ 6,586	\$ 8,383	\$ (1,797)
Interest on long-term notes	20,246	23,015	(2,769)	41,253	47,288	(6,035)
Interest on lease obligations	58	124	(66)	118	251	(133)
Cash interest	\$ 23,554	\$ 27,387	\$ (3,833)	\$ 47,957	\$ 55,922	\$ (7,965)
Accretion of debt issue costs	790	665	125	1,539	5,107	(3,568)
Accretion of asset retirement obligations	3,367	2,178	1,189	5,665	5,109	556
Gain on redemption of long-term notes	(357)	—	(357)	(357)	—	(357)
Early redemption expense	—	—	—	—	3,312	(3,312)
Financing and interest expense	\$ 27,354	\$ 30,230	\$ (2,876)	\$ 54,804	\$ 69,450	\$ (14,646)
Cash interest per boe	\$ 3.19	\$ 4.15	\$ (0.96)	\$ 3.31	\$ 3.59	\$ (0.28)
Financing and interest expense per boe	\$ 3.70	\$ 4.58	\$ (0.88)	\$ 3.79	\$ 4.46	\$ (0.67)

Financing and interest expense was \$27.4 million (\$3.70/boe) for Q2/2021 and \$54.8 million (\$3.79/boe) for YTD 2021 compared to \$30.2 million (\$4.58/boe) for Q2/2020 and \$69.5 million (\$4.46/boe) for YTD 2020.

Cash interest of \$23.6 million (\$3.19/boe) for Q2/2021 and \$48.0 million (\$3.31/boe) for YTD 2021 is lower than \$27.4 million (\$4.15/boe) for Q2/2020 and \$55.9 million (\$3.59/boe) for YTD 2020 primarily due to lower interest on our long-term notes. The reported interest on our U.S. dollar denominated long-term notes was lower as the average principal amount of long-term notes outstanding was lower during YTD 2021 due to the refinancing transactions completed in Q1/2020 along with the strengthening of the Canadian dollar for Q2/2021 and YTD 2021 relative to the same periods of 2020. Interest on our credit facilities was lower in Q2/2021 and YTD 2021 compared to the same periods of 2020 due to lower borrowings on our credit facilities and lower effective interest rates. The weighted average interest rate applicable to our credit facilities was 2.1% for Q2/2021 and YTD 2021 compared to 2.3% and 2.7% in Q2/2020 and YTD 2020, respectively.

Financing and interest expense for YTD 2021 was lower than YTD 2020 which included the accelerated amortization of debt issue costs and \$3.3 million of early redemption expense associated with the redemption of notes in Q1/2020.

Cash interest expense of \$3.31/boe for YTD 2021 is slightly above our revised annual guidance of \$3.27/boe as the strength of the Canadian dollar has reduced our interest expense. We expect cash interest expense of \$95 million (\$3.27/boe) for 2021.

[illegible]

The following table summarizes the recoverable amount and impairment reversal at June 30, 2021 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	\$ 57,891	\$ 15,000	\$ 1,000	\$ 1,000	\$ 8,000
Peace River CGU	238,714	154,000	4,000	40,000	2,500
Lloydminster CGU	340,730	154,000	12,500	52,000	—
Duvernay CGU ⁽¹⁾	115,157	5,000	45,000	44,500	44,500
Viking CGU	1,338,985	356,000	47,000	89,500	4,500
Eagle Ford CGU	2,015,118	442,415	109,400	103,900	24,400
	\$ 4,106,595	\$ 1,126,415	\$ 218,900	\$ 330,900	\$ 83,900

(1) The impairment reversal for the Duvernay CGU was limited to total accumulated impairments less subsequent depletion of \$5.0 million.

We recorded total net impairments of \$2.4 billion for the year ended December 31, 2020 due to significant changes in forecasted commodity prices caused by the COVID-19 pandemic.

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 an impairment loss 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 loss recorded at Q1/2020 included \$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.

Share-Based Compensation Expense

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit 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 associated with the Deferred Share Unit Plan is recognized in net income or loss on the grant date 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 \$2.8 million for Q2/2021 and \$5.8 million for YTD 2021 which is consistent with \$3.0 million for Q2/2020 and \$5.8 million for YTD 2020. The total expense for YTD 2021 is comprised of non-cash compensation expense of \$3.2 million related to the Share Award Incentive Plan and cash compensation expense of \$2.6 million related to the Incentive Award Plan and the Deferred Share Unit 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.

	Three Months Ended June 30			Six Months Ended June 30		
(\$ thousands except for exchange rates)	2021	2020	Change	2021	2020	Change
Unrealized foreign exchange (gain) loss	\$ (1,792)	\$ (45,516)	\$ 12,579	\$ (4,322)	\$ 54,005	\$ 26,320
Realized foreign exchange gain	(464)	(457)	(7)	(739)	(86)	(653)
Foreign exchange (gain) loss	\$ (2,256)	\$ (45,973)	\$ 43,717	\$ (5,061)	\$ 53,919	\$ (58,980)
CAD/USD exchange rates:						
At beginning of period	1.2572	1.4120		1.2755	1.2965	
At end of period	1.2405	1.3616		1.2405	1.3616	

We recorded unrealized foreign exchange gains of \$1.8 million for Q2/2021 and \$4.3 million for YTD 2021 compared to a gain of \$45.5 million for Q2/2020 and a loss of \$54.0 million for YTD 2020.

In September 2020, we issued a series of intercompany notes totaling US\$751.0 million issued from a Canadian subsidiary to a U.S. subsidiary. We recorded unrealized foreign exchange losses of \$12.6 million for Q2/2021 and \$26.3 million for YTD 2021 on our intercompany notes issued by our Canadian subsidiary due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021 compared to March 31, 2021 and December 31, 2020, respectively. There were no unrealized foreign exchange gains or losses on our intercompany notes recorded in Q2/2020 or YTD 2020.

We recorded unrealized foreign exchange gains on our long-term notes of \$14.4 million for Q2/2021 and \$30.6 million for YTD 2021 due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021 compared to March 31, 2021 and December 31, 2020, respectively. This compares to an unrealized foreign exchange gain of \$45.5 million for Q2/2020 due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2020 compared to March 31, 2020, and an unrealized foreign exchange loss of \$54.0 million for YTD 2020 due to the weakening of the Canadian dollar at June 30, 2020 compared to December 31, 2019.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded realized foreign exchange gains of \$0.5 million for Q2/2021 and \$0.7 million for YTD 2021 compared to \$0.5 million for Q2/2020 and \$0.1 million for YTD 2020.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
(\$ thousands)	2021	2020	Change	2021	2020	Change
Current income tax expense	\$ 568	\$ 89	\$ 479	\$ 408	\$ 558	\$ (150)
Deferred income tax expense (recovery)	56,051	21,002	35,049	61,715	(262,177)	323,892
Total income tax expense (recovery)	\$ 56,619	\$ 21,091	\$ 35,528	\$ 62,123	\$ (261,619)	\$ 323,742

Current income tax expense was \$0.6 million for Q2/2021 and \$0.4 million for YTD 2021 compared to \$0.1 million for Q2/2020 and \$0.6 million for YTD 2020.

We recorded deferred tax expense of \$56.1 million for Q2/2021 and \$61.7 million for YTD 2021 compared to an expense of \$21.0 million for Q2/2020 and a recovery of \$262.2 million for YTD 2020. The deferred tax expense recorded in YTD 2021 is primarily related to the impairment reversal recorded in YTD 2021 whereas the deferred tax recovery recorded in YTD 2020 is primarily related to the impairment loss recorded in YTD 2020.

As disclosed in the 2020 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.

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the three and six months ended June 30, 2021 and 2020 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
(\$ thousands)	2021	2020	Change	2021	2020	Change
Petroleum and natural gas sales	\$ 442,354	\$ 152,689	\$ 289,665	\$ 827,056	\$ 489,303	\$ 337,753
Royalties	(81,531)	(29,156)	(52,375)	(148,481)	(85,876)	(62,605)
Revenue, net of royalties	360,823	123,533	237,290	678,575	403,427	275,148
Expenses						
Operating	(82,901)	(73,680)	(9,221)	(163,449)	(178,150)	14,701
Transportation	(7,486)	(5,031)	(2,455)	(16,274)	(15,373)	(901)
Blending and other	(19,967)	(5,460)	(14,507)	(37,087)	(26,817)	(10,270)
Operating netback	\$ 250,469	\$ 39,362	\$ 211,107	\$ 461,765	\$ 183,087	\$ 278,678
General and administrative	(10,610)	(7,438)	(3,172)	(19,343)	(17,213)	(2,130)
Cash financing and interest	(23,554)	(27,387)	3,833	(47,957)	(55,922)	7,965
Realized financial derivatives (loss) gain	(39,024)	13,624	(52,648)	(59,792)	40,474	(100,266)
Realized foreign exchange gain	464	457	7	739	86	653
Other income (expense)	(170)	(24)	(146)	62	2,007	(1,945)
Current income tax expense	(568)	(89)	(479)	(408)	(558)	150
Cash share-based compensation	(1,124)	(618)	(506)	(2,601)	(1,139)	(1,462)
Adjusted funds flow	\$ 175,883	\$ 17,887	\$ 157,996	\$ 332,465	\$ 150,822	\$ 181,643
Exploration and evaluation	(3,005)	(1,831)	(1,174)	(3,952)	(2,091)	(1,861)
Depletion and depreciation	(103,055)	(104,540)	1,485	(205,067)	(285,926)	80,859
Non-cash share-based compensation	(1,646)	(2,375)	729	(3,150)	(4,637)	1,487
Non-cash financing and accretion	(3,800)	(2,843)	(957)	(6,847)	(13,528)	6,681
Non-cash other income	676	—	676	1,664	—	1,664
Unrealized financial derivatives (loss) gain	(84,483)	(69,286)	(15,197)	(170,467)	26,709	(197,176)
Unrealized foreign exchange gain (loss)	1,792	45,516	(43,724)	4,322	(54,005)	58,327
Gain on dispositions	274	11	263	3,980	148	3,832
Impairment	1,126,414	—	1,126,414	1,126,414	(2,716,349)	3,842,763
Deferred income tax (expense) recovery	(56,051)	(21,002)	(35,049)	(61,715)	262,177	(323,892)
Net income (loss) for the period	\$ 1,052,999	\$ (138,463)	\$ 1,191,462	\$ 1,017,647	\$ (2,636,680)	\$ 3,654,327

We generated adjusted funds flow of \$175.9 million for Q2/2021 and \$332.5 million for YTD 2021 compared to \$17.9 million for Q2/2020 and \$150.8 million for YTD 2020. The increase in adjusted funds flow for both periods of 2021 was primarily due to higher operating netback which increased \$211.1 million from Q2/2020 and \$278.7 million from YTD 2020 as a result of higher commodity prices which increased revenue, net of royalties. The increase in operating netback was partially offset by realized losses on financial derivatives of \$39.0 million for Q2/2021 and \$59.8 million for YTD 2021 due to the increase in oil and natural gas benchmark prices relative to Q2/2020 and YTD 2020 when we recorded realized gains on financial derivatives of \$13.6 million and \$40.5 million, respectively.

We reported net income of \$1.05 billion for Q2/2021 and \$1.02 billion for YTD 2021 compared to a net loss of \$138.5 million reported for Q2/2020 and a net loss of \$2.64 billion for YTD 2020. Net income in both periods of 2021 is a result of an impairment reversal of \$1.13 billion recorded in Q2/2021 compared to YTD 2020 when we recorded an impairment loss of \$2.72 billion.

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 foreign currency translation losses of \$0.1 million for Q2/2021 and \$7.2 million for YTD 2021 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the Canadian dollar strengthening relative to the U.S. dollar at June 30, 2021 compared to March 31, 2021 and December 31, 2020. The CAD/USD exchange rate was 1.2405 CAD/USD as at June 30, 2021 compared to 1.2572 CAD/USD at March 31, 2021 and 1.2755 CAD/USD at December 31, 2020.

Capital Expenditures

Capital expenditures for the three and six months ended June 30, 2021 and 2020 are summarized as follows.

Three Months Ended June 30						
	2021			2020		
(\$ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Drilling, completion and equipping	\$ 23,018	\$ 30,911	\$ 53,929	\$ 8	\$ 6,768	\$ 6,776
Facilities	4,682	9	4,691	2,693	—	2,693
Land, seismic and other	2,687	178	2,865	228	155	383
Total exploration and development	\$ 30,387	\$ 31,098	\$ 61,485	\$ 2,929	\$ 6,923	\$ 9,852
Total acquisitions, net of proceeds from divestitures	\$ (18)	\$ —	\$ (18)	\$ (11)	\$ —	\$ (11)

Six Months Ended June 30						
	2021			2020		
(\$ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Drilling, completion and equipping	\$ 62,052	\$ 71,633	\$ 133,685	\$ 99,545	\$ 59,839	\$ 159,384
Facilities	7,197	13	7,210	21,697	299	21,996
Land, seismic and other	3,641	537	4,178	4,798	451	5,249
Total exploration and development	\$ 72,890	\$ 72,183	\$ 145,073	\$ 126,040	\$ 60,589	\$ 186,629
Total acquisitions, net of proceeds from divestitures	\$ (221)	\$ —	\$ (221)	\$ (51)	\$ —	\$ (51)

Exploration and development expenditures were \$61.5 million for Q2/2021 and \$145.1 million for YTD 2021 compared to \$9.9 million for Q2/2020 and \$186.6 million for YTD 2020. Expenditures in Q2/2021 were higher compared to Q2/2020 as development activity was reduced in Canada and the U.S. following the sharp decline in commodity prices in March 2020.

In Canada, we invested \$30.4 million on exploration and development activities in Q2/2021 which is \$27.5 million higher than \$2.9 million in Q2/2020. Exploration and development expenditures of \$30.4 million for Q2/2021 included costs associated with drilling 16 (16.0 net) light oil wells, 2 (2.0 net) heavy oil wells, and investing \$4.7 million on facilities. Exploration and development expenditures of \$2.9 million for Q2/2020 reflects the suspension of drilling and completion operations following the sharp decline in crude oil prices in March 2020. Exploration and development expenditures of \$72.9 million for YTD 2021 included costs associated with drilling 53 (52.2 net) light oil wells, 7 (3.9 net) heavy oil wells, 1 (1.0 net) natural gas well, and investing \$7.2 million on facilities. Exploration and development expenditures of \$126.0 million for YTD 2020 included costs associated with drilling 74 (71.2 net) light oil wells, 33 (33.0 net) heavy oil wells, and investing \$21.7 million on facilities.

Total U.S. exploration and development expenditures were \$31.1 million for Q2/2021 which is \$24.2 million higher than \$6.9 million for Q2/2020. Exploration and development expenditures for Q2/2021 included costs associated with drilling 16 (1.7 net) wells along with 38 (10.2 net) wells that were brought on production. Exploration and development expenditures of \$6.9 million for Q2/2020 reflects reduced drilling and completion activity following the sharp decline in crude oil pricing in March 2020 and includes final costs associated with 17 (4.6 net) wells that were brought on production during April 2020. Exploration and development expenditures of \$72.2 million for YTD 2021 included costs associated with drilling 41 (9.2 net) wells along with 62 (17.2 net) wells that were brought on production. Exploration and development expenditures of \$60.6 million for YTD 2020 included costs associated with drilling 17 (3.8 net) wells along with 47 (10.7 net) wells that were brought on production.

Our exploration and development expenditures for YTD 2021 are consistent with expectations and we continue to forecast expenditures of \$285 - \$315 million for 2021.

CAPITAL RESOURCES AND LIQUIDITY

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 June 30, 2021, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

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 internally generated adjusted funds flow and availability under our 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.

Management of debt levels is a priority for Baytex in order to sustain operations and support our long-term plans. At June 30, 2021, net debt of \$1.63 billion was \$218.0 million lower than \$1.85 billion at December 31, 2020. The decrease in net debt is primarily a result of free cash flow of \$183.0 million generated during YTD 2021 being allocated to debt repayment along with a \$35.0 million decrease in the reported amount of our U.S. dollar denominated net debt due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021 compared to December 31, 2020.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a trailing twelve month basis. At June 30, 2021, our net debt to adjusted funds flow ratio was 3.3 compared to a ratio of 5.9 as at December 31, 2020. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2020 is attributed to a \$218.0 million decrease in net debt as at June 30, 2021 combined with higher adjusted funds flow for the twelve months ended June 30, 2021.

Credit Facilities

At June 30, 2021, the principal amount of credit facilities and letters of credit outstanding was \$501.4 million under our credit facilities that total approximately \$1.0 billion. Our credit facilities include US\$575 million of revolving credit facilities and a \$300 million non-revolving term loan (collectively, the "Credit Facilities"). Our Credit Facilities mature on April 2, 2024 and 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 transition begins on December 31, 2021. Certain tenors of the U.S. dollar LIBOR benchmark will no longer be published as of December 31, 2021 while some tenors will continue to be published through mid-2023. We expect the U.S. dollar LIBOR benchmarks 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 2.1% for Q2/2021 and YTD 2021 compared to 2.3% for Q2/2020 and 2.7% for YTD 2020.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2021.

Covenant Description	Position as at June 30, 2021	Covenant
Senior Secured Debt ⁽¹⁾ to Bank EBITDA ⁽²⁾ (Maximum Ratio)	0.8:1.0	3.5:1.0
Interest Coverage ⁽³⁾ (Minimum Ratio)	6.0:1.0	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 June 30, 2021, the Company's Senior Secured Debt totaled \$501.4 million which includes \$486.6 million of principal amounts outstanding and \$14.7 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 June 30, 2021 was \$592.2 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 June 30, 2021 were \$98.3 million.

Long-Term Notes

We have two series of long-term notes outstanding that total \$1.1 billion as at June 30, 2021. 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"). 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.

During Q2/2021, we purchased and cancelled US\$5.8 million principal of the 5.625% Notes at a discount and recorded a gain of \$0.4 million. Subsequent to June 30, 2021, we amended the 2014 note indenture to expand our permitted secured indebtedness to align these amounts with the 2020 indenture. We also used free cash flow generated in the first half of 2021 to repurchase and cancel US\$100.0 million principal amount of the 5.625% Notes due 2024 at the call price of 100.938%, plus accrued interest, effective July 28, 2021.

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 six months ended June 30, 2021, we issued 3.0 million common shares pursuant to our share-based compensation program. As at July 28, 2021, we had 564.2 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 June 30, 2021 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	\$ 200,355	\$ 200,355	\$ —	\$ —	\$ —
Credit facilities ^{(1) (2)}	486,623	—	486,623	—	—
Long-term notes ⁽²⁾	1,109,211	—	488,986	—	620,225
Interest on long-term notes ⁽³⁾	392,641	81,775	161,290	108,539	41,037
Lease agreements ⁽²⁾	9,431	4,265	3,506	1,660	—
Processing agreements	5,944	820	1,037	473	3,614
Transportation agreements	86,190	16,119	39,041	19,057	11,973
Total	\$ 2,290,395	\$ 303,334	\$ 1,180,483	\$ 129,729	\$ 676,849

(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.

QUARTERLY FINANCIAL INFORMATION

	2021		2020				2019	
(\$ thousands, except per common share amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	442,354	384,702	233,636	252,538	152,689	336,614	445,895	424,600
Net income (loss)	1,052,999	(35,352)	221,160	(23,444)	(138,463)	(2,498,217)	(117,772)	15,151
Per common share - basic	1.87	(0.06)	0.39	(0.04)	(0.25)	(4.46)	(0.21)	0.03
Per common share - diluted	1.85	(0.06)	0.39	(0.04)	(0.25)	(4.46)	(0.21)	0.03
Adjusted funds flow	175,883	156,582	82,176	78,508	17,887	132,935	232,147	213,379
Per common share - basic	0.31	0.28	0.15	0.14	0.03	0.24	0.42	0.38
Per common share - diluted	0.31	0.28	0.15	0.14	0.03	0.24	0.42	0.38
Exploration and development	61,485	83,588	77,809	15,902	9,852	176,777	153,117	139,085
Canada	30,387	42,503	45,030	3,882	2,929	123,110	104,460	96,774
U.S.	31,098	41,085	32,779	12,020	6,923	53,667	48,657	42,311
Acquisitions, net of divestitures	(18)	(203)	(33)	(98)	(11)	(40)	563	(30)
Net debt	1,629,629	1,758,894	1,847,601	1,906,079	1,994,953	2,051,617	1,871,791	1,971,339
Total assets	4,438,162	3,338,408	3,408,096	3,156,414	3,267,820	3,441,040	5,914,083	6,233,875
Common shares outstanding	564,182	564,111	561,227	561,163	560,545	560,483	558,305	557,972
Daily production								
Total production (boe/d)	81,162	78,780	70,475	77,814	72,508	98,452	96,360	94,927
Canada (boe/d)	47,205	52,039	45,321	49,164	37,691	62,262	57,794	58,134
U.S. (boe/d)	33,957	26,741	25,154	28,650	34,817	36,190	38,566	36,793
Benchmark prices								
WTI oil (US\$/bbl)	66.07	57.84	42.66	40.93	27.85	46.17	56.96	56.45
WCS heavy (\$/bbl)	67.03	57.46	43.46	42.40	22.70	34.48	54.29	58.39
Edmonton Light (\$/bbl)	77.28	66.58	50.24	49.83	29.85	51.43	58.10	68.41
CAD/USD avg exchange rate	1.2279	1.2663	1.3031	1.3316	1.3860	1.3445	1.3201	1.3207
AECO gas (\$/mcf)	2.85	2.93	2.77	2.18	1.91	2.14	2.34	1.04
NYMEX gas (US\$/mmbtu)	2.83	2.69	2.66	1.98	1.72	1.95	2.50	2.23
Sales price (\$/boe)	57.19	51.84	34.35	33.79	22.31	35.19	48.25	47.14
Royalties (\$/boe)	(11.04)	(9.44)	(5.83)	(5.59)	(4.42)	(6.33)	(8.72)	(8.59)
Operating expense (\$/boe)	(11.22)	(11.36)	(12.30)	(10.26)	(11.17)	(11.66)	(11.23)	(11.15)
Transportation expense (\$/boe)	(1.01)	(1.24)	(1.03)	(0.89)	(0.76)	(1.15)	(1.00)	(1.13)
Operating netback (\$/boe)	33.92	29.80	15.19	17.05	5.96	16.05	27.30	26.27
Financial derivatives gain (loss) (\$/boe)	(5.28)	(2.93)	2.64	(1.36)	2.06	3.00	2.59	2.39
Operating netback after financial derivatives (\$/boe)	28.64	26.87	17.83	15.69	8.02	19.05	29.89	28.66

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 relatively consistent from Q3/2019 to Q1/2020 as relatively stable crude oil prices supported an active development program in Canada and the U.S. until the sharp decline in crude oil prices in March 2020 when we shut-in production in Canada and moderated the pace of activity in the U.S. Commodity prices began to recover in Q4/2020 and have strengthened in YTD 2021 which supported increased development activity and resulted in production of 81,162 boe/d for Q2/2021.

North American benchmark commodity prices were stable throughout 2019 and relatively strong leading into Q1/2020 with the West Texas Intermediate ("WTI") benchmark price averaging US\$57.53/bbl in January 2020. 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 and were relatively stable through the second half of 2020 as OPEC+ agreed to reinstate production curtailments and measures to control the spread of COVID-19 were

relaxed. Commodity prices continued to recover in 2021 with WTI averaging US\$66.07/bbl in Q2/2021 as the outlook for demand improved with increasing global mobility. The impact of increased commodity prices is reflected in our realized sales price of \$57.19/boe for Q2/2021 which is our strongest realized pricing in the previous eight quarters.

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 for Q2/2021 compared to lows in 2020 due to strong price realizations and our ongoing efforts to control operating and transportation costs.

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 \$1.97 billion at Q3/2019 to \$1.63 billion at Q2/2021 as free cash flow of \$345.7 million generated over the last eight quarters was directed towards debt repayment. 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 1.3244 CAD/USD at Q3/2019 to 1.2405 CAD/USD at Q2/2021.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 30, 2021, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the six months ended June 30, 2021. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2020.

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 shares 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.

	Three Months Ended June 30		Six Months Ended June 30	
(\$ thousands)	2021	2020	2021	2020
Cash flow from operating activities	\$ 171,876	\$ 25,824	\$ 292,856	\$ 208,391
Change in non-cash working capital	3,014	(8,565)	37,199	(62,438)
Asset retirement obligations settled	993	628	2,410	4,869
Adjusted funds flow	\$ 175,883	\$ 17,887	\$ 332,465	\$ 150,822

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.

	Three Months Ended June 30		Six Months Ended June 30	
(\$ thousands)	2021	2020	2021	2020
Cash flow used in investing activities	\$ 44,856	\$ 55,782	\$ 122,033	\$ 216,804
Change in non-cash working capital	16,931	(44,566)	23,230	(28,239)
Proceeds from dispositions	18	11	246	51
Property acquisitions	—	—	(25)	—
Additions to other plant and equipment	(320)	(1,375)	(411)	(1,987)
Exploration and development expenditures	\$ 61,485	\$ 9,852	\$ 145,073	\$ 186,629

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.

	Three Months Ended June 30		Six Months Ended June 30	
(\$ thousands)	2021	2020	2021	2020
Adjusted funds flow	\$ 175,883	\$ 17,887	\$ 332,465	\$ 150,822
Exploration and development expenditures	(61,485)	(9,852)	(145,073)	(186,629)
Payments on lease obligations	(919)	(1,468)	(2,001)	(2,984)
Asset retirement obligations settled	(993)	(628)	(2,410)	(4,869)
Free cash flow	\$ 112,486	\$ 5,939	\$ 182,981	\$ (43,660)

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)	June 30, 2021	December 31, 2020
Credit facilities ⁽¹⁾	\$ 486,623	\$ 651,173
Long-term notes ⁽¹⁾	1,109,211	1,147,950
Trade and other payables	200,355	155,955
Cash	(1,375)	—
Trade and other receivables	(165,185)	(107,477)
Net debt	\$ 1,629,629	\$ 1,847,601

(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.

	Three Months Ended June 30		Six Months Ended June 30	
(\$ thousands)	2021	2020	2021	2020
Petroleum and natural gas sales	\$ 442,354	\$ 152,689	\$ 827,056	\$ 489,303
Blending and other expense	(19,967)	(5,460)	(37,087)	(26,817)
Total sales, net of blending and other expense	422,387	147,229	789,969	462,486
Royalties	(81,531)	(29,156)	(148,481)	(85,876)
Operating expense	(82,901)	(73,680)	(163,449)	(178,150)
Transportation expense	(7,486)	(5,031)	(16,274)	(15,373)
Operating netback	250,469	39,362	461,765	183,087
Realized financial derivative (loss) gain	(39,024)	13,624	(59,792)	40,474
Operating netback after realized financial derivatives	\$ 211,445	\$ 52,986	\$ 401,973	\$ 223,561

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.

	Twelve Months Ended June 30	
(\$ thousands)	2021	2020
Net income (loss)	\$ 1,215,363	\$ (2,739,301)
Plus:		
Financing and interest	110,795	130,032
Unrealized foreign exchange (gain) loss	(49,095)	43,511
Unrealized financial derivatives loss	215,676	17,520
Current income tax (recovery) expense	424	1,561
Deferred income tax expense (recovery)	162,925	(314,692)
Depletion and depreciation	405,521	646,486
Gain on dispositions	(4,733)	(1,329)
Impairment loss (recovery)	(1,482,543)	2,904,171
Non-cash items ⁽¹⁾	17,851	13,168
Bank EBITDA	\$ 592,184	\$ 701,127

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

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended June 30, 2021.

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 2021 guidance with respect to exploration and development expenditures, average daily production, royalty rate and operating, transportation, general and administrative and interest expenses; 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 manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; that a significant portion of our financial obligations will be funded by adjusted funds flow; our expectations with respect to the LIBOR transition and that we do not expect it to have a material impact on Baytex; and the circumstances in which we would be eligible to terminate our reporting obligations under the Securities Exchange Act of 1934, as amended.

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); availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2020, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

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