enerPLUS

FINANCIAL SUMMARY

2020

CONTENTS

2020 FINANCIAL SUMMARY

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2020	2019	2020	2019
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$(204,167)	$(429,143)	$(923,367)	$(259,720)
Adjusted Net Income(1)	22,149	34,365	19,758	243,160
Cash Flow from Operating Activities	96,079	188,492	446,365	694,240
Adjusted Funds Flow(1)	91,871	178,922	358,160	708,992
Dividends to Shareholders - Declared	6,677	6,656	26,698	27,688
Total Debt Net of Cash(1)	375,967	454,984	375,967	454,984
Capital Spending	52,414	99,389	291,468	618,910
Property and Land Acquisitions	2,061	6,126	10,121	24,406
Property Divestments	47	(316)	6,145	9,583
Net Debt to Adjusted Funds Flow Ratio(1)	1.0x	0.6x	1.0x	0.6x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ (0.92)	$ (1.93)	$ (4.15)	$ (1.12)
Net Income/(Loss) - Diluted	(0.92)	(1.93)	(4.15)	(1.12)
Weighted Average Number of Shares Outstanding (000's) - Basic	222,548	222,227	222,503	231,334
Weighted Average Number of Shares Outstanding (000's) - Diluted	222,548	222,227	222,503	231,334
Selected Financial Results per BOE(2)(3)				
Crude Oil & Natural Gas Sales(4)	$ 30.60	$ 41.64	$ 27.82	$ 42.65
Royalties and Production Taxes	(7.67)	(10.93)	(7.12)	(10.88)
Commodity Derivative Instruments	3.12	0.07	3.95	0.42
Operating Expenses	(8.20)	(8.05)	(7.94)	(7.88)
Transportation Costs	(3.89)	(3.82)	(3.99)	(3.93)
General and Administrative Expenses	(1.46)	(1.34)	(1.35)	(1.32)
Cash Share-Based Compensation	(0.11)	0.01	0.04	(0.02)
Interest, Foreign Exchange and Other Expenses	(0.81)	(0.89)	(1.06)	(0.72)
Current Income Tax Recovery	—	1.41	0.44	0.91
Adjusted Funds Flow(1)	$ 11.58	$ 18.10	$ 10.79	$ 19.23

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2020	2019	2020	2019
Average Daily Production(3)				
Crude Oil (bbls/day)	43,405	54,344	45,421	49,704
Natural Gas Liquids (bbls/day)	5,790	5,502	5,633	4,929
Natural Gas (Mcf/day)	222,293	285,537	237,857	278,451
Total (BOE/day)	86,244	107,436	90,697	101,042
% Crude Oil and Natural Gas Liquids	57%	56%	56%	54%
Average Selling Price(3)(4)				
Crude Oil (per bbl)	$ 47.95	$ 67.23	$ 44.35	$ 68.98
Natural Gas Liquids (per bbl)	17.19	18.28	10.29	15.19
Natural Gas (per Mcf)	2.04	2.50	1.87	2.87
Net Wells Drilled	2	9	42	56

(1) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.
(2) Non-cash amounts have been excluded.
(3) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(4) Before transportation costs, royalties and commodity derivative instruments.

Average Benchmark Pricing	Three months ended December 31, 2020	2019	Twelve months ended December 31, 2020	2019
WTI crude oil (US$/bbl)	$ 42.66	$ 56.96	$ 39.40	$ 57.03
Brent (ICE) crude oil (US$/bbl)	45.24	62.51	43.21	64.18
NYMEX natural gas – last day (US$/Mcf)	2.66	2.50	2.08	2.63
US/CDN average exchange rate	1.30	1.32	1.34	1.33

Share Trading Summary For the twelve months ended December 31, 2020	CDN[1] – ERF (CDN$)	U.S.[2] – ERF (US$)
High	$ 9.55	$ 7.35
Low	$ 1.62	$ 1.15
Close	$ 3.98	$ 3.13

(1) TSX and other Canadian trading data combined.
(2) NYSE and other U.S. trading data combined.

2020 Dividends per Share	CDN$	US$[1]
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.12	$ 0.08

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

2020 HIGHLIGHTS

Financial & Operational Highlights

- We delivered 2020 production at the high end of our annual guidance ranges, with total production of 90,697 BOE/day, including crude oil and natural gas liquids production of 51,054 bbls/day, a decrease of 10% and 7%, respectively, compared to 2019 due to the temporary curtailment of crude oil production during the second quarter and the significant reduction in capital activity in North Dakota during 2020 in response to the decline in crude oil prices. Natural gas production decreased 15% year-over-year due to lower capital activity for our Marcellus natural gas asset during 2020.

- Full year 2020 cash flow from operating activities and adjusted funds flow were $446.4 million and $358.2 million, respectively, compared to $694.2 million and $709.0 million, respectively, in 2019. Cash flow from operating activities and adjusted funds flow decreased from 2019 due to lower benchmark crude oil prices and reduced production volumes.

- We reported a full year 2020 net loss of $923.4 million, or ($4.15) per share, compared to a net loss of $259.7 million, or ($1.12) per share, in 2019. The higher net loss was primarily due to larger non-cash impairment charges, lower benchmark crude oil prices and reduced production volumes in 2020. We recorded non-cash impairments totaling $1,197.6 million in 2020 related to property, plant and equipment ("PP&E") and goodwill due to the low commodity price environment and the use of 12-month trailing prices to test for impairment, as required under U.S. Securities and Exchange Commission ("SEC") guidelines. Excluding these impairments and certain other non-cash or non-recurring items, full year 2020 adjusted net income was $19.8 million, or $0.09 per share, compared to $243.2 million, or $1.05 per share, in 2019. Adjusted net income decreased from 2020 due to lower benchmark crude oil prices and reduced production volumes.

- Our 2020 Bakken crude oil price differential was US$4.96/bbl below WTI, compared to US$3.61/bbl below WTI in 2019. The weaker year-over-year differential was due to the significant benchmark oil price volatility and the narrowing of Brent-WTI differentials in 2020. Our 2020 Marcellus natural gas price differential was US$0.65/Mcf below NYMEX, compared to US$0.39/Mcf below NYMEX in 2019. Regional pricing in the Marcellus was particularly weak from September to November of 2020 due to nearly full regional storage combined with low demand due to mild weather.

- Operating expenses in 2020 were $7.94/BOE, compared to $7.88/BOE in 2019. Cash G&A expenses in 2020 were $1.35/BOE, compared to $1.32/BOE in 2019.

- Exploration and development capital spending totaled $291.4 million in 2020, below our capital budget guidance of $295 million. We paid $26.7 million in dividends in 2020.

- We ended the year with total debt net of cash of $376.0 million, a decrease from $455.0 million in 2019, and we were undrawn on our US$600 million unsecured bank credit facility. At December 31, 2020, our net debt to adjusted funds flow ratio was 1.0x.

Reserves Highlights

- Total proved plus probable ("2P") reserves were 424.4 MMBOE at year end 2020, 4% lower than year end 2019.

- We replaced 50% of our total 2020 production, adding 16.7 MMBOE of 2P reserves (including technical revisions and economic factors). In North Dakota, we replaced 69% of our 2020 production, adding 11.3 MMBOE of 2P reserves.

- Excluding economic factors, we replaced 89% of our total 2020 production, adding 29.2 MMBOE of 2P reserves. In North Dakota, we replaced 119% of our 2020 production excluding economic factors, adding 19.4 MMBOE of 2P reserves. Economic factors are reserves revisions due to the significant reduction in year-over-year forecast prices.

- F&D costs were $26.51/BOE for proved developed producing ("PDP") reserves, $6.78/BOE for proved reserves, and $6.50/BOE for 2P reserves, including future development costs ("FDC").

- Finding, development and acquisition ("FD&A") costs were $6.97/BOE for proved reserves and $6.74/BOE for 2P reserves, including FDC.

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 18, 2021 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of this MD&A for further information.

BASIS OF PRESENTATION

The Financial Statements and notes have been prepared in accordance with U.S. GAAP. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and crude oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1 or 0.167:1, as applicable, utilizing a conversion on this basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101– Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities. All reserves information presented herein has been prepared in accordance with NI 51-101 and is presented at December 31, 2020 unless otherwise stated.

All references to "liquids" in this MD&A include light and medium oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis. All references to "natural gas" in this MD&A include conventional natural gas and shale gas.

In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in the Financial Statements. Under International Financial Reporting Standards, industry standard is to present crude oil and natural gas sales before deduction of royalties and as such this MD&A presents production, crude oil and natural gas sales, and BOE measures before deduction of royalties to remain comparable with our Canadian peers.

Unless otherwise expressly stated, information presented in this MD&A does not give effect to the proposed acquisition (the "Bruin Acquisition") by Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of the Company, of all of the equity interests of Bruin E&P HoldCo, LLC ("Bruin") from Bruin Purchaser LLC pursuant to a membership interest purchase and sale agreement dated as of January 25, 2021 (the "Purchase Agreement").

The following table provides a reconciliation of our production volumes:

	Year ended December 31,		
Average Daily Production Volumes	**2020**	**2019**	**2018**
Company interest production volumes			
Light and medium oil (bbls/day)	3,277	3,908	4,287
Heavy oil (bbls/day)	3,901	4,717	4,995
Tight oil (bbls/day)	38,243	41,079	36,142
Total crude oil (bbls/day)	45,421	49,704	45,424
Natural gas liquids (bbls/day)	5,633	4,929	4,486
Conventional natural gas (Mcf/day)	12,314	23,400	27,159
Shale gas (Mcf/day)	225,543	255,051	232,678
Total natural gas (Mcf/day)	237,857	278,451	259,837
Company interest production volumes (BOE/day)	90,697	101,042	93,216
Royalty volumes			
Light and medium oil (bbls/day)	676	944	957
Heavy oil (bbls/day)	477	969	916
Tight oil (bbls/day)	7,587	8,121	7,181
Total crude oil (bbls/day)	8,740	10,034	9,054
Natural gas liquids (bbls/day)	1,134	977	951
Conventional natural gas (Mcf/day)	898	2,080	2,588
Shale gas (Mcf/day)	45,945	50,790	46,335
Total natural gas (Mcf/day)	46,843	52,870	48,923
Royalty volumes (BOE/day)	17,681	19,823	18,159
Net production volumes			
Light and medium oil (bbls/day)	2,601	2,964	3,330
Heavy oil (bbls/day)	3,424	3,748	4,079
Tight oil (bbls/day)	30,656	32,958	28,961
Total crude oil (bbls/day)	36,681	39,670	36,370
Natural gas liquids (bbls/day)	4,499	3,952	3,535
Conventional natural gas (Mcf/day)	11,416	21,320	24,571
Shale gas (Mcf/day)	179,598	204,261	186,343
Total natural gas (Mcf/day)	191,014	225,581	210,914
Net production volumes (BOE/day)	73,016	81,219	75,057

2020 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 86,244 BOE/day, at the high end of our fourth quarter production guidance range of 84,000 – 87,000 BOE/day and a decrease compared to third quarter 2020 production of 91,022 BOE/day. Crude oil and natural gas liquids production averaged 49,195 bbls/day compared to the third quarter average of 52,539 bbls/day and exceeded our fourth quarter liquids production guidance range of 47,000 – 49,000 bbls/day. Our fourth quarter capital spending was $52.4 million, bringing total 2020 capital spending to $291.4 million, below our guidance of $295 million.

We reported a net loss of $204.2 million in the fourth quarter compared to a net loss of $112.8 million in the third quarter of 2020. The increase in net loss was primarily the result of a $311.2 million non-cash PP&E impairment recorded in the fourth quarter compared to a $256.8 million PP&E impairment in the third quarter, both as a result of the low commodity price environment and the requirement to use SEC twelve month trailing prices to test for impairment.

Fourth quarter cash flow from operating activities decreased to $96.1 million from $137.0 million in the third quarter of 2020 primarily due to a decrease in non-cash operating working capital of $8.9 million during the fourth quarter, compared to a change of $55.8 million in the third quarter. Fourth quarter adjusted funds flow increased to $91.9 million, from $83.1 million during the third quarter, largely due to a $5.0 million increase in realized cash gains on commodity derivative instruments during the fourth quarter.

Selected Fourth Quarter Canadian and U.S. Financial Results

($ millions, except per unit amounts)	Three months ended December 31, 2020 Canada	U.S.	Total	Three months ended December 31, 2019 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Light and medium oil (bbls/day)	3,192	—	3,192	3,560	—	3,560
Heavy oil (bbls/day)	4,216	—	4,216	4,587	—	4,587
Tight oil (bbls/day)	—	35,997	35,997	—	46,197	46,197
Total crude oil (bbls/day)	7,408	35,997	43,405	8,147	46,197	54,344
Natural gas liquids (bbls/day)	580	5,210	5,790	797	4,705	5,502
Conventional natural gas (Mcf/day)	10,381	—	10,381	21,379	—	21,379
Shale gas (Mcf/day)	146	211,766	211,912	285	263,873	264,158
Total natural gas (Mcf/day)	10,527	211,766	222,293	21,664	263,873	285,537
Total average daily production (BOE/day)	9,743	76,501	86,244	12,555	94,881	107,436
Pricing(2)						
Crude oil (per bbl)	$ 41.75	$ 49.22	$ 47.95	$ 55.69	$ 69.26	$ 67.23
Natural gas liquids (per bbl)	26.68	16.14	17.19	28.61	16.53	18.28
Natural gas (per Mcf)	3.25	1.98	2.04	2.53	2.50	2.50
Capital Expenditures						
Capital spending	$ 2.9	$ 49.5	$ 52.4	$ 7.5	$ 91.9	$ 99.4
Acquisitions	0.5	1.6	2.1	3.1	3.0	6.1
Divestments	—	—	—	0.3	—	0.3
Netback(3) **Before Hedging**						
Crude oil and natural gas sales	$ 33.4	$ 209.3	$ 242.7	$ 49.5	$ 362.1	$ 411.6
Royalties	(4.7)	(43.0)	(47.7)	(11.3)	(73.3)	(84.6)
Production taxes	(0.5)	(12.7)	(13.2)	(0.7)	(22.8)	(23.5)
Operating expenses	(14.0)	(51.1)	(65.1)	(18.2)	(61.3)	(79.5)
Transportation costs	(2.4)	(28.4)	(30.8)	(2.1)	(35.7)	(37.8)
Netback before hedging	$ 11.8	$ 74.1	$ 85.9	$ 17.2	$ 169.0	$ 186.2
Other Expenses						
Asset impairment	$ 33.5	$ 277.7	$ 311.2	$ —	$ —	$ —
Goodwill impairment	—	—	—	451.1	—	451.1
Commodity derivative instruments loss/(gain)	12.5	—	12.5	28.8	—	28.8
General and administrative expense(4)	3.3	13.2	16.5	8.7	10.1	18.8
Current income tax recovery	—	—	—	—	(14.0)	(14.0)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation.

Comparing the fourth quarter of 2020 with the same period in 2019:

- Average daily production was 86,244 BOE/day, a decrease of 20% from 107,436 BOE/day. The decrease in crude oil production was a result of the suspension of our operated North Dakota drilling and completions program early in 2020 as a result of weak commodity prices. Natural gas production decreased due to limited capital activity in the Marcellus and our decision to shut-in, abandon and reclaim our Canadian natural gas property in Tommy Lakes during the first quarter of 2020. These impacts were partially offset by an increase in natural gas liquids production over the same period due to an increase in natural gas liquids recoveries.

- Our crude oil and natural gas liquids production accounted for 57% of our total production mix in the fourth quarter of 2020, compared to 56% in 2019.

- Capital spending decreased to $52.4 million compared to $99.4 million in the fourth quarter of 2019 due to the suspension of our operated North Dakota drilling and completions program early in 2020. The majority of our capital investment in the fourth quarter of 2020 was focused on our U.S. crude oil properties, including the completion of four drilled uncompleted wells and approximately three net-operated wells.

- Operating expenses decreased to $65.1 million ($8.20/BOE) compared to $79.5 million ($8.05/BOE) in the fourth quarter of 2019. Operating costs increased on a per BOE basis due to lower production.

- Cash general and administrative ("G&A") expenses decreased to $11.6 million compared to $13.3 million in 2019, however increased on a per BOE basis totaling $1.46/BOE in the fourth quarter of 2020, compared to $1.34/BOE in the same period of 2019 due to lower production.

- During the fourth quarter of 2020, our Bakken crude oil price differential widened to US$4.82/bbl below WTI, compared to US$4.40/bbl below WTI for the same period in 2019, due to much narrower Brent-WTI differentials. Our fourth quarter 2020 Marcellus natural gas differential was US$1.07/Mcf below NYMEX, compared to US$0.63/Mcf below NYMEX during the same period in 2019. Regional pricing in the Marcellus was particularly weak from September to November 2020 due to nearly full regional storage combined with low demand due to mild weather.

- We reported a net loss of $204.2 million in the fourth quarter of 2020 compared to net loss of $429.1 million in the fourth quarter of 2019. Our net loss decreased by $224.9 million due to lower non-cash impairment charges, with a non-cash PP&E impairment of $311.2 million recorded in the fourth quarter of 2020 compared to a non-cash goodwill impairment of $451.1 million recorded in the fourth quarter of 2019. The decrease in the net loss was also due to a $116.7 million deferred income tax recovery in the fourth quarter of 2020 compared to an expense of $31.8 million in the same period in 2019.

- Cash flow from operating activities and adjusted funds flow decreased to $96.1 million and $91.9 million, respectively, compared to $188.5 million and $178.9 million, respectively, in the fourth quarter of 2019. The decreases were primarily the result of a $132.0 million decrease in crude oil and natural gas sales, net of royalties, partially offset by $24.7 million in realized cash gains on commodity derivative instruments in the fourth quarter of 2020.

- Net debt to adjusted funds flow increased to 1.0x in the fourth quarter of 2020 compared to 0.6x in the fourth quarter of 2019.

2020 OVERVIEW

Summary of Guidance and Results	Revised 2020 Guidance	2020 Results
Capital spending ($ millions)	$295	$291
Average annual production (BOE/day)	90,000 - 91,000	90,697
Average annual crude oil and natural gas liquids production (bbls/day)	50,500 - 51,000	51,054
Fourth quarter average production (BOE/day)	84,000 - 87,000	86,244
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	47,000 - 49,000	49,195
Average royalty and production tax rate (% of gross sales, before transportation)	26%	26%
Operating expenses (per BOE)	$8.00	$7.94
Transportation costs (per BOE)	$4.00	$3.99
Cash G&A expenses (per BOE)	$1.35	$1.35

Differential/Basis Outlook and Results(1)		
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(5.00)/bbl	US$(4.96)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	US$(0.60)/Mcf	US$(0.65)/Mcf

(1) Excludes transportation costs

The coronavirus ("COVID-19") pandemic had a major impact on the global economy in 2020 and posed significant challenges for our industry. In response to a dramatic decline in crude oil demand and historically low prices during the second quarter of 2020, we temporarily curtailed certain wells across our crude oil and natural gas liquids properties and suspended our operated drilling and completions activity in North Dakota. In response to strengthening prices, our previously curtailed production was fully restored during the third quarter and we completed four net operated wells in North Dakota and approximately three net non-operated wells during the fourth quarter. Although markets remain volatile and the timing of a full economic recovery remains uncertain, crude oil prices continue to improve as supply moderates and demand levels begin to recover. We remained committed to preserving our strong financial position through a focus on reducing costs, maintaining capital discipline and delivering strong operational performance.

Our 2020 annual average production was 90,697 BOE/day with crude oil and natural gas liquids volumes of 51,054 bbls/day, meeting our revised production guidance target of 90,000 – 91,000 BOE/day and exceeding our revised crude oil and natural gas liquids production guidance of 50,500 – 51,000 bbls/day. Our capital spending for the year totaled $291.4 million, below our revised guidance of $295 million. The majority of our capital was directed to our U.S. crude oil properties, with approximately 80% of total spending focused on our North Dakota and Colorado properties.

Our Bakken sales price differentials widened in comparison to the prior year averaging US$4.96/bbl below WTI, in line with our guidance of US$5.00/bbl below WTI. Bakken differentials were negatively impacted by the significant benchmark oil price volatility and the narrowing of the Brent-WTI price differentials in 2020. Our Marcellus differential of US$0.65/Mcf below NYMEX was slightly higher than our revised differential outlook of US$0.60/Mcf below NYMEX and wider than our 2019 differential of US$0.39/Mcf below NYMEX. Regional pricing in the Marcellus was particularly weak from September to November of 2020 as a result of nearly full regional storage combined with low demand due to mild weather.

Operating expenses were $7.94/BOE, below our revised guidance of $8.00/BOE. Cash G&A expenses were $1.35/BOE, in line with our revised guidance of $1.35/BOE.

Cash flow from operations and adjusted funds flow decreased to $446.4 million and $358.2 million, respectively, from $694.2 million and $709.0 million, respectively, in 2019. The decrease was mainly due to a $517.6 million reduction in crude oil and natural gas sales, net of royalties, due to a decrease in realized commodity prices and lower production compared to 2019. This was partially offset by a $115.6 million increase in realized commodity derivative instrument gains.

We reported a net loss of $923.4 million in 2020, an increase from a net loss of $259.7 million in 2019. Our net loss was impacted by non-cash impairments of $994.8 million on PP&E and $202.8 million on goodwill as a result of low commodity prices. These reductions were partially offset by a total income tax recovery of $260.8 million in 2020 compared to an expense of $47.9 million in 2019.

Total debt net of cash at December 31, 2020 was $376.0 million, comprised of $490.4 million of senior notes less $114.5 million in cash. At December 31, 2020, we were undrawn on our US$600 million senior unsecured bank credit facility and had a net debt to adjusted funds flow ratio of 1.0x.

2021 OUTLOOK

On January 25, 2021, we entered into the Purchase Agreement to acquire all the equity interests of Bruin, a pure play Williston Basin private company, for total cash consideration of US$465 million, with no assumption of debt and subject to certain adjustments. On the same date, we entered into a binding commitment letter for a new three-year senior unsecured US$400 million term facility (the "Term Facility") to be fully drawn down on the closing date of the Bruin Acquisition to pay for a portion of the purchase price. We intend to fund the remaining portion of the purchase price with net proceeds from a $132.3 million bought deal equity financing, which we completed on February 3, 2021. Closing of the Bruin Acquisition is expected to occur early in March 2021 and is subject to customary closing conditions and purchase price adjustments including those related to the fair value of Bruin's commodity hedge contracts. Bruin's current production is approximately 24,000 BOE/day (72% tight oil, 14% natural gas liquids, and 14% natural gas). Refer to the material change report dated January 29, 2021 in connection with the Bruin Acquisition and available under the Enerplus' SEDAR profile at www.sedar.com and on the Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

We expect that the Bruin Acquisition will further support our 2021 strategy of creating value for our shareholders through strong free cash flow generation and disciplined returns-oriented focus, while maintaining balance sheet strength. We expect our net debt to trailing adjusted funds flow ratio to be approximately 1.0x at year end 2021 based on WTI of US$55.00/bbl and NYMEX of US$3.00/Mcf. We expect to be undrawn on our US$600 million credit facility upon the closing of the Bruin Acquisition.

Our 2021 production volumes are expected to average 103,500 – 108,500 BOE/day, including 63,000 – 67,000 bbl/day of crude oil and natural gas liquids production, assuming the Bruin Acquisition closes in early March 2021 and a ten-month contribution from Bruin's assets. Based on the same assumption, we expect our capital budget range for 2021 is between $335 million and $385 million, with the majority directed to our North Dakota assets.

We expect our Bakken sales price differential to narrow to US$3.25/bbl below WTI in 2021, assuming the Dakota Access Pipeline ("DAPL") continues to operate, an improvement from our 2020 differential of US$4.96/bbl below WTI. The expected improvement is due to declining regional production leading to increased pipeline egress. In the Marcellus, we have a differential outlook of US$0.55/Mcf below NYMEX in 2021.

To support our 2021 capital program, and assuming the closing of the Bruin Acquisition, we have hedged approximately 21,500 bbls/day and 17,000 bbls/day, respectively, of our expected crude oil production for 2021 and 2022. For natural gas, we have hedged 60,000 Mcf/day for March 2021 and 100,000 Mcf/day for April 1 to October 31, 2021.

We plan to provide additional 2021 guidance upon the closing of the Bruin Acquisition.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2020	2019	2018
Light and medium oil (bbls/day)	3,277	3,908	4,287
Heavy oil (bbls/day)	3,901	4,717	4,995
Tight oil (bbls/day)	38,243	41,079	36,142
Total crude oil (bbls/day)	45,421	49,704	45,424
Natural gas liquids (bbls/day)	5,633	4,929	4,486
Conventional natural gas (Mcf/day)	12,314	23,400	27,159
Shale gas (Mcf/day)	225,543	255,051	232,678
Total natural gas (Mcf/day)	237,857	278,451	259,837
Total daily sales (BOE/day)	90,697	101,042	93,216

Production in 2020 averaged 90,697 BOE/day, in line with our revised production guidance range of 90,000 – 91,000 BOE/day, and resulting in a 10% decrease compared to 2019 production of 101,042 BOE/day. Crude oil and natural gas liquids production in 2020 averaged 51,054 bbls/day, exceeding our revised guidance range of 50,500 – 51,500 bbls/day. Compared to 2019, our crude oil and natural gas liquids production decreased 7% due to the temporary curtailment of certain crude oil and natural gas liquids properties and the suspension of all operated drilling and completion activity in North Dakota during the second quarter of 2020, in response to the significant decline in crude oil prices.

Our U.S. production volumes decreased by 8% compared to 2019 and our U.S. crude oil and natural gas liquids production decreased by 4% to 43,248 bbls/day, primarily due to temporary production curtailments and the suspension of our operated North Dakota drilling and completions program early in 2020 due to weak commodity prices. Our U.S. natural gas production decreased by 12% due to limited capital activity in the Marcellus.

Canadian production volumes decreased by 27% compared to the prior year, due to our decision to shut-in, abandon and reclaim our Canadian natural gas property in Tommy Lakes during the first quarter of 2020.

Our crude oil and natural gas liquids production accounted for 56% of our total average daily production in 2020, an increase from 54% in 2019.

Production for 2019 increased by 7,826 BOE/day to 101,042 BOE/day, compared to 2018. The 8% increase was largely due to an increase to the 2019 capital spending program and additional wells brought on-stream in North Dakota and Colorado. During the same period, U.S. natural gas production increased 10% due to strong well performance in the Marcellus in 2019.

2021 Guidance

We expect annual average production for 2021 of 103,500 – 108,500 BOE/day, including 63,000 – 67,000 bbls/day of crude oil and natural gas liquids production, assuming the closing of the Bruin Acquisition in early March 2021 and a ten month contribution from Bruin's assets in 2021.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, cash flow from operating activities, adjusted funds flow and financial condition. The following table summarizes our average selling prices, benchmark prices and differentials:

Pricing (average for the period)	2020	2019	2018
Benchmarks			
WTI crude oil (US$/bbl)	$ 39.40	$ 57.03	$ 64.77
Brent (ICE) crude oil (US$/bbl)	43.21	64.18	71.53
NYMEX natural gas – last day (US$/Mcf)	2.08	2.63	3.09
US/CDN average exchange rate	1.34	1.33	1.30
US/CDN period end exchange rate	1.27	1.30	1.36
Enerplus selling price(1)			
Crude oil ($/bbl)	$ 44.35	$ 68.98	$ 74.59
Natural gas liquids ($/bbl)	10.29	15.19	28.31
Natural gas ($/Mcf)	1.87	2.87	3.42
Average benchmark differentials			
Bakken DAPL - WTI (US$/bbl)	$ (4.27)	$ (3.46)	$ (3.73)
Brent (ICE) - WTI (US$/bbl)	3.81	7.15	6.77
MSW Edmonton – WTI (US$/bbl)	(5.33)	(4.88)	(11.12)
WCS Hardisty – WTI (US$/bbl)	(12.60)	(12.76)	(26.31)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.72)	(0.46)	(0.64)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.34	0.23	0.75
Enerplus realized differentials(1)(2)			
Bakken crude oil – WTI (US$/bbl)	$ (4.96)	$ (3.61)	$ (3.78)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.65)	(0.39)	(0.43)
Canada crude oil – WTI (US$/bbl)	(13.04)	(12.11)	(21.83)

(1) Excluding transportation costs, royalties and the effects of commodity derivative instruments.
(2) Based on a weighted average differential for the period.

CRUDE OIL AND NATURAL GAS LIQUIDS

Benchmark WTI prices averaged US$39.40/bbl in 2020, a 31% decrease from 2019, largely due to the COVID-19 pandemic and the resulting reduction in crude oil demand due to restrictions on mobility and travel. WTI prices fell sharply in the second quarter of 2020, at one point reaching negative values in April, which resulted in production curtailments across North America that helped balance the market further throughout the year. The Organization of Petroleum Exporting Countries ("OPEC") lowered its production quotas in response to the pandemic in the spring. Crude oil markets recovered through the second half of the year as global economies stabilized and demand for crude oil began to recover. This resulted in lower global crude oil storage and higher WTI prices at the end of the year. Our 2020 realized crude oil price averaged $44.35/bbl, representing a 36% decrease compared to 2019 and a 31% decrease in benchmark WTI prices as a result of wider Bakken crude oil differentials compared to the previous year.

Our Bakken sales price differentials weakened in 2020 compared to 2019, averaging US$4.96/bbl below WTI, in line with our guidance of US$5.00/bbl below WTI. Bakken prices were volatile in the second quarter of 2020 due to significant benchmark oil price fluctuations. Additionally, weakness in U.S. Gulf Coast grades and a narrow Brent-WTI differential reduced our realized pricing on physical sales that were linked to these markets. We expect our realized Bakken differential to average US$3.25/bbl below WTI in 2021, assuming DAPL continues to operate.

Canadian crude oil differentials weakened slightly in 2020 compared to the prior year. Differentials were weaker in the first quarter of 2020 prior to industry wide production curtailments. Differentials narrowed after April and throughout the remainder of year as spare capacity increased on export pipelines as a result of lower production levels.

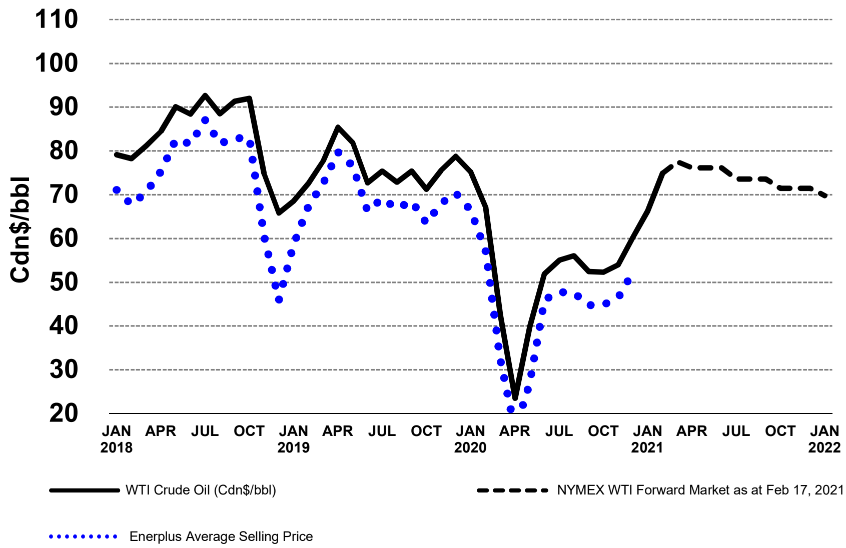
We realized an average price of $10.29/bbl on our natural gas liquids production in 2020, a 32% decrease compared to 2019 and in line with changes to benchmark oil prices. A significant portion of our natural gas liquid sales are linked to WTI prices, particularly condensate and butane.

NATURAL GAS

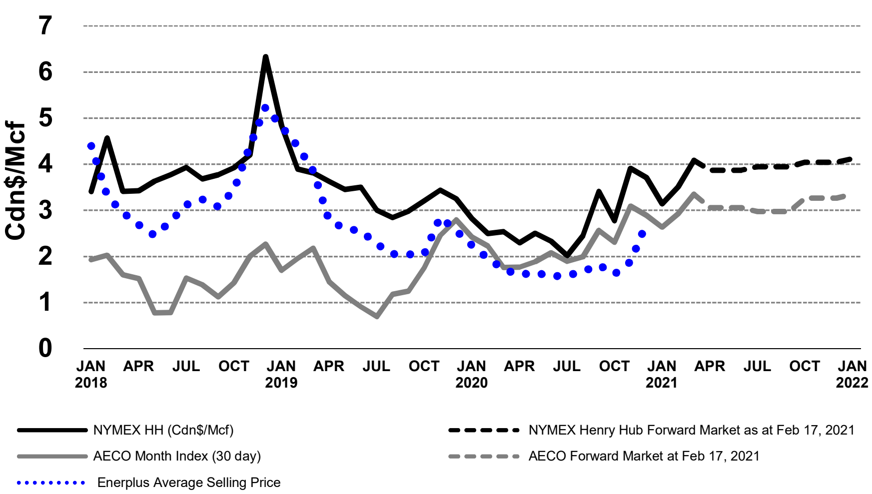
Our realized natural gas price averaged $1.87/Mcf in 2020, a 35% decrease from 2019. This decrease was greater than the 21% decline in benchmark natural gas prices due to significantly weaker gas prices in the Marcellus in 2020.

In the Marcellus, we realized an average sales price differential of US$0.65/Mcf below NYMEX, slightly higher than our revised guidance of $0.60/Mcf below NYMEX for the year and wider compared to our 2019 realized sales price differential of $0.39/Mcf. The Transco Leidy monthly benchmark differential averaged US$0.72/Mcf below NYMEX for 2020, which was weaker than 2019 as the local market suffered from high storage levels and a lack of weather-induced demand, particularly in the shoulder months of September and October. At the same time, NYMEX Natural Gas prices at Henry Hub were significantly stronger due to the much improved supply and demand outlook for the upcoming winter. Transco Z6 Non-New York Leidy monthly benchmark differentials averaged US$0.34/Mcf above NYMEX for 2020, a slight improvement over the full 2019 differential. We expect our Marcellus differential to average US$0.55/Mcf below NYMEX in 2021.

Monthly Crude Oil Prices



Monthly Natural Gas Prices

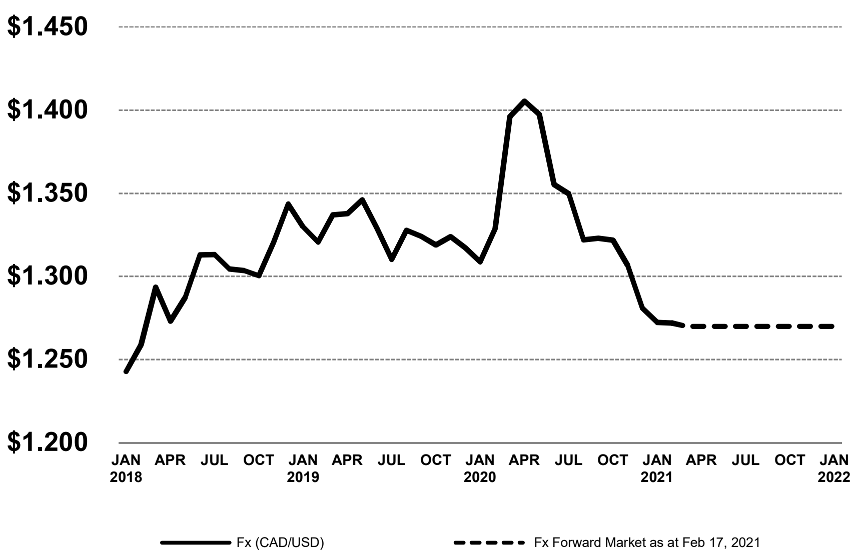


FOREIGN EXCHANGE

Our crude oil and natural gas sales are impacted by foreign exchange fluctuations as the majority of our sales are based on U.S. dollar denominated benchmark indices. A stronger Canadian dollar decreases the amount of our realized sales, as well as the amount of our U.S. denominated costs, such as capital, the interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes.

The Canadian dollar weakened during 2020 in response to lower commodity prices as a result of the global excess supply of crude oil and the decreased demand impact of the COVID-19 pandemic. The USD/CDN exchange rate peaked at 1.45 USD/CDN in March and remained volatile for the remainder of the year, resulting in an average exchange rate of 1.34 USD/CDN during 2020 compared to an average of 1.33 in 2019. The Canadian dollar strengthened at the end of the 2020 to close at 1.27 USD/CDN compared to 1.30 USD/CDN at December 31, 2019.

Monthly USD/CDN Exchange Rate



Price Risk Management

We have a price risk management program that considers our overall financial position and the economics of our capital expenditures.

As of February 18, 2021, we have hedged approximately 21,500 bbls/day and 17,000 bbls/day, respectively, of our expected crude oil production for 2021 and 2022. Our crude oil hedges are predominantly three way collars. The three way collars provide us with exposure to significant upward price moves; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts. For natural gas, we have hedged 60,000 Mcf/day for March 2021 and 100,000 Mcf/day for April 1 to October 31, 2021. Overall, we expect our crude oil and natural gas related hedging contracts to protect a significant portion of our cash flow from operating activities and adjusted funds flow in both 2021 and 2022.

The following is a summary of Enerplus' financial contracts in place at February 18, 2021:

	WTI Crude Oil (US$/bbl)[1]				NYMEX Natural Gas (US$/Mcf)	
	Jan 1, 2021 – Mar 31, 2021	Apr 1, 2021- Jun 30, 2021	Jul 1, 2021 - Dec 31, 2021	Jan 1 ,2022 - Dec 31, 2022	Mar 1, 2021- Mar 31, 2021	Apr 1, 2021 - Oct 31, 2021
Swaps						
Volume (bbls/d or Mcf/d)	5,000	-	-	-	60,000	60,000
Sold Swaps	$ 45.55	-	-	-	$ 3.16	$ 2.90
Three Way Collars						
Volume (bbls/d or Mcf/d)	15,000	20,000	23,000	17,000	-	40,000
Sold Puts	$ 32.00	$ 32.00	$ 36.39	$ 40.00	-	$ 2.15
Purchased Puts	$ 40.53	$ 40.90	$ 46.39	$ 50.00	-	$ 2.75
Sold Calls	$ 50.29	$ 50.72	$ 56.70	$ 57.91	-	$ 3.25

(1) The total average deferred premium spent on our outstanding hedges is US$0.80/bbl from January 1, 2021 – December 31, 2021 and US$1.50/bbl from January 1, 2022 – December 31, 2022.

As of February 18, 2021, the following is a summary of Bruin's financial contracts, which Enerplus will assume upon the close of the Bruin Acquisition.

	WTI Crude Oil (US$/bbl)[(1)(2)]			
	Mar 1, 2021 - Dec 31, 2021	Jan 1, 2022 - Dec 31, 2022	Jan 1, 2023 - Oct 31, 2023	Nov 1, 2023- Dec 31, 2023
Swaps				
Volume (bbls/d)	9,000	3,900	250	-
Sold Swaps	$ 42.35	$ 42.38	$ 42.10	-
Collars				
Volume (bbls/d)	-	-	2,000	2,000
Purchased Puts	-	-	$ 5.00	$ 5.00
Sold Calls	-	-	$ 75.00	$ 75.00

(1) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(2) Upon close of the Bruin Acquisition, these hedges will be recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges will be recorded in the Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets, respectively, to reflect changes in WTI prices from the date of the close of the Bruin Acquisition.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Derivative Instruments Gains/(Losses)

($ millions)	2020	2019	2018
Cash gains/(losses):			
Crude oil	$ 131.0	$ (12.1)	$ (52.0)
Natural gas	—	27.4	16.2
Total cash gains/(losses)	$ 131.0	$ 15.3	$ (35.8)
Non-cash gains/(losses):			
Crude oil	$ (25.7)	$ (70.5)	$ 114.8
Natural gas	3.5	(10.9)	9.2
Total non-cash gains/(losses)	$ (22.2)	$ (81.4)	$ 124.0
Total commodity derivative instruments gains/(losses)	$ 108.8	$ (66.1)	$ 88.2

(Per BOE)	2020	2019	2018
Total cash gains/(losses)	$ 3.95	$ 0.42	$ (1.05)
Total non-cash gains/(losses)	(0.66)	(2.21)	3.64
Total commodity derivative instruments gains/(losses)	$ 3.29	$ (1.79)	$ 2.59

During 2020, we realized cash gains of $131.0 million on crude oil contracts and no cash gains or losses on our natural gas contracts, compared to cash losses of $12.1 million on crude oil contracts and cash gains of $27.4 million on our natural gas contracts in 2019. Cash gains in 2020 on crude oil contracts were primarily due to prices falling below the swap level as well as the net effect of benchmark prices below the put levels on both our put spreads and three way collars.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. The fair value of our crude oil contracts at December 31, 2020 was a net liability position of $15.6 million (December 31, 2019 – net asset position of $10.1 million). The fair value of our natural gas contracts at December 31, 2020 was in a net asset position of $3.5 million (December 31, 2019 – no contracts outstanding). The change in fair value of our crude oil and natural gas contracts represented losses of $25.7 million and gains of $3.5 million, respectively, during 2020 and losses of $70.5 million and $10.9 million, respectively, during 2019.

Revenues

($ millions)	2020	2019	2018
Crude oil and natural gas sales	$ 923.5	$ 1,572.9	$ 1,610.9
Royalties	(186.3)	(318.1)	(318.2)
Crude oil and natural gas sales, net of royalties	$ 737.2	$ 1,254.8	$ 1,292.7

Crude oil and natural gas sales revenue for 2020 totaled $923.5 million, a decrease of 41% from $1,572.9 million in 2019. The decrease in revenue was a result of lower commodity prices and a decrease in production volumes.

Crude oil and natural gas sales revenue for 2019 totaled $1,572.9 million, a decrease of 2% from $1,610.9 million in 2018. The decrease in revenue was a result of lower commodity prices, which more than offset the increase in production volumes.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2020	2019	2018
Royalties	$ 186.3	$ 318.1	$ 318.2
Per BOE	$ 5.61	$ 8.63	$ 9.35
Production taxes	$ 49.9	$ 83.1	$ 87.3
Per BOE	$ 1.51	$ 2.25	$ 2.57
Royalties and production taxes	$ 236.2	$ 401.2	$ 405.5
Per BOE	$ 7.12	$ 10.88	$ 11.92
Royalties and production taxes (% of crude oil and natural gas sales)	25.6%	25.5%	25.2%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada and less sensitive to commodity price levels.

Royalties and production taxes were in line with our guidance of 26% for 2020, averaging 25.6% of crude oil and natural gas sales, before transportation. Royalties and production taxes of $236.2 million in 2020, decreased in comparison to prior years due to lower realized commodity prices and production volumes. Royalties and production taxes of $401.2 million in 2019 were consistent with 2018, but decreased on a per BOE basis due to lower realized commodity prices.

Operating Expenses

($ millions, except per BOE amounts)	2020	2019	2018
Operating expenses	$ 263.6	$ 290.8	$ 238.3
Per BOE	$ 7.94	$ 7.88	$ 7.00

Operating expenses for 2020 were $263.6 million or $7.94/BOE, beating our revised guidance of $8.00/BOE and representing a decrease of $27.2 million or an increase of $0.06/BOE from the prior year. The decrease was largely due to lower fluid handling costs associated with lower production volumes. This was partially offset by additional well service activity and repairs and maintenance during the third quarter of 2020, as previously curtailed production was restored.

Operating expenses for 2019 were $290.8 million or $7.88/BOE, representing an increase of $52.5 million or $0.88/BOE from 2018. The increase was mainly attributable to additional well service activity, higher fluid handling costs and gas processing charges related to our North Dakota asset.

Transportation Costs

($ millions, except per BOE amounts)	2020	2019	2018
Transportation costs	$ 132.4	$ 144.9	$ 123.5
Per BOE	$ 3.99	$ 3.93	$ 3.63

Transportation costs in 2020 were in line with our revised guidance of $4.00/BOE, averaging $3.99/BOE or $132.4 million, compared to $3.93/BOE or $144.9 million in 2019. The reduction in transportation costs was primarily a result of lower U.S. production with higher associated transportation costs compared to the same period in the prior year, partly due to price related production curtailments in the second quarter of 2020. On a per BOE basis, transportation costs were in line with the prior year.

Transportation costs in 2019 were $3.93/BOE, an increase from $3.63/BOE in 2018. The overall increase in transportation costs were due to additional crude oil firm transportation commitments that provide access to sell a portion of our production at U.S. Gulf Coast or Brent pricing that commenced March 1, 2019.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Year ended December 31, 2020		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	56,055 BOE/day	207,855 Mcfe/day	90,697 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 37.78	$ 1.95	$ 27.82
Royalties and production taxes	(10.07)	(0.39)	(7.12)
Operating expenses	(11.75)	(0.29)	(7.94)
Transportation costs	(2.90)	(0.96)	(3.99)
Netback before hedging	$ 13.06	$ 0.31	$ 8.77
Cash gains/(losses)	6.38	—	3.95
Netback after hedging	$ 19.44	$ 0.31	$ 12.72
Netback before hedging ($ millions)	$ 268.0	$ 23.3	$ 291.3
Netback after hedging ($ millions)	$ 399.0	$ 23.3	$ 422.3

	Year ended December 31, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	58,679 BOE/day	254,177 Mcfe/day	101,042 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 60.60	$ 2.97	$ 42.65
Royalties and production taxes	(16.30)	(0.56)	(10.88)
Operating expenses	(12.23)	(0.31)	(7.88)
Transportation costs	(2.97)	(0.88)	(3.93)
Netback before hedging	$ 29.10	$ 1.22	$ 19.96
Cash gains/(losses)	(0.57)	0.30	0.42
Netback after hedging	$ 28.53	$ 1.52	$ 20.38
Netback before hedging ($ millions)	$ 623.3	$ 112.7	$ 736.0
Netback after hedging ($ millions)	$ 611.1	$ 140.3	$ 751.4

(1) See "Non-GAAP Measures" in this MD&A.

Netbacks by Property Type	Year ended December 31, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	53,294 BOE/day	239,532 Mcfe/day	93,216 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 67.43	$ 3.42	$ 47.35
Royalties and production taxes	(17.90)	(0.65)	(11.92)
Operating expenses	(10.54)	(0.38)	(7.00)
Transportation costs	(2.40)	(0.88)	(3.63)
Netback before hedging	$ 36.59	$ 1.51	$ 24.80
Cash gains/(losses)	(2.67)	0.19	(1.05)
Netback after hedging	$ 33.92	$ 1.70	$ 23.75
Netback before hedging ($ millions)	$ 711.7	$ 131.9	$ 843.6
Netback after hedging ($ millions)	$ 659.7	$ 148.1	$ 807.8

(1) See "Non-GAAP Measures" in this MD&A.

As a result of the low commodity price environment, total netbacks before and after hedging decreased by 60% and 44%, respectively, in 2020 compared to 2019. Our price risk management program continued to provide adjusted funds flow protection, with realized cash gains on our crude oil derivative instruments partially offsetting the impact of lower realized pricing. During 2020, our crude oil properties accounted for 92% and 94% of our netback before and after hedging, respectively, compared to 85% and 81%, respectively, in 2019.

General and Administrative Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 11, Note 14 and Note 15 to the Financial Statements for further details.

($ millions)	2020	2019	2018
Cash:			
G&A expense	$ 44.9	$ 48.8	$ 50.0
Share-based compensation expense	(1.4)	0.7	0.1
Non-Cash:			
Share-based compensation expense	13.0	22.3	25.9
Equity swap loss/(gain)	1.4	0.3	(0.2)
G&A expense/(recovery)	(0.3)	0.7	—
Total G&A expenses	$ 57.6	$ 72.8	$ 75.8

(Per BOE)	2020	2019	2018
Cash:			
G&A expense	$ 1.35	$ 1.32	$ 1.47
Share-based compensation expense	(0.04)	0.02	0.01
Non-Cash:			
Share-based compensation expense	0.39	0.61	0.76
Equity swap loss/(gain)	0.04	0.01	(0.01)
G&A expense/(recovery)	(0.01)	0.02	—
Total G&A expenses	$ 1.73	$ 1.98	$ 2.23

Cash G&A expenses were $44.9 million, or $1.35/BOE, in 2020, meeting our revised guidance of $1.35/BOE and lower in comparison to our 2019 Cash G&A of $48.8 million, or $1.32/BOE. Cash G&A expenses were lower in 2020 in part due to government funding received related to the second quarter, at the height of the uncertainty brought on by the COVID-19 pandemic, which reimbursed qualifying Canadian employers for a portion of salaries paid. Cash G&A expenses were further lowered by cash compensation reductions for our Board of Directors, executives and employees in effect during a portion of 2020, and other non-salary cost saving initiatives.

During 2020, we reported a cash SBC recovery of $1.4 million due to the impact of a lower share price on our outstanding Director Deferred Share Units ("DSUs") and Director Restricted Share Units ("RSUs"), compared to an expense of $0.7 million in 2019. We recorded a non-cash SBC expense of $13.0 million, or $0.39/BOE, in 2020, compared to an expense of $22.3 million, or $0.61/BOE, in 2019. The decrease in non-cash SBC in 2020 was a result of a lower multiplier on our Performance Share Units ("PSUs") compared to 2019.

Cash G&A expenses in 2019 were $48.8 million, or $1.32/BOE, a decrease from $50.0 million, or $1.47/BOE, in 2018, mostly due to an increase in our production over the period. Cash SBC expense was $0.7 million, or $0.02/BOE, in 2019 compared to an expense of $0.1 million, or $0.01/BOE, in 2018. We recorded non-cash SBC of $22.3 million, or $0.61/BOE in 2019 compared to $25.9 million, or $0.76/BOE, in 2018. The decrease in non-cash SBC in 2019 was a result of a lower multiplier on our PSUs compared to 2018.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. We recorded a non-cash mark-to-market loss of $1.4 million on these hedges in 2020 (2019 – $0.3 million loss; 2018 – $0.2 million gain).

Interest Expense

Interest on our senior notes and bank credit facility for 2020 totaled $28.4 million, a decrease of 16% from $33.9 million in 2019. The decrease was due to the repayment of a portion of our 2009 and 2012 senior notes during the second quarter of 2020.

Interest on our senior notes and bank credit facility for 2019 of $33.9 million decreased compared to $36.8 million in 2018 due to the repayment of a portion of our 2009 senior notes and the bullet repayment of the full principal amount of our 2012 $30 million senior notes during 2019.

At December 31, 2020, we were undrawn on our US$600 million bank credit facility and our debt consisted of fixed interest rate senior notes with a weighted average interest rate of 4.4%. See Note 7 to the Financial Statements for further details on our outstanding notes.

Foreign Exchange

($ millions)	2020	2019	2018
Realized:			
Foreign exchange loss/(gain) on settlements	$ 0.6	$ (0.1)	$ 0.5
Translation of U.S. dollar cash held in Canada loss/(gain)	(1.2)	8.8	(19.6)
Unrealized loss/(gain)	1.9	(34.1)	58.6
Total foreign exchange loss/(gain)	$ 1.3	$ (25.4)	$ 39.5
US/CDN average exchange rate	1.34	1.33	1.30
US/CDN period end exchange rate	1.27	1.30	1.36

We recorded a total foreign exchange loss of $1.3 million in 2020, compared to a gain of $25.4 million in 2019 and a loss of $39.5 million in 2018. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and the translation of our U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated bank debt and working capital held in Canada at each period-end.

Effective January 1, 2020, we have designated our outstanding senior notes as a net investment hedge related to our U.S. operations. As a result of the adoption of net investment hedge accounting, any unrealized foreign exchange gains and losses on the translation of this U.S. dollar denominated debt are included in Other Comprehensive Income/(Loss). At December 31, 2020, US$385.4 million of senior notes outstanding were designated as a net investment hedge. For the year ended December 31, 2020, Other Comprehensive Income/(Loss) included an unrealized gain of $2.2 million on our outstanding U.S. dollar denominated senior notes. For December 31, 2019 and 2018, the unrealized gains and losses recorded on the translation of our senior notes was included in Consolidated Net Income/(Loss). Comparing December 31, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $34.1 million. See Note 2(k) to the Financial Statements for further details.

Capital Investment

($ millions)	2020	2019	2018
Capital spending	$ 291.4	$ 618.9	$ 593.9
Office capital	4.3	5.8	6.5
Line fill	—	5.1	—
Sub-total	295.7	629.8	600.4
Property and land acquisitions	$ 10.1	$ 24.4	$ 25.8
Property divestments	(6.1)	(9.6)	(6.9)
Sub-total	4.0	14.8	18.9
Total(1)	$ 299.7	$ 644.6	$ 619.3

(1) Excludes changes in non-cash investing working capital. See Note 18(b) of the Consolidated Financial Statements for additional information.

2020

Capital spending in 2020 totaled $291.4 million, lower than our revised guidance of $295 million. In 2020, we spent $234.8 million on our U.S. crude oil properties, $22.9 million on our Canadian crude oil properties and $33.1 million on our Marcellus natural gas assets. The decrease in capital spending in 2020 compared to prior years was mainly due to minimal drilling and completions activity in North Dakota during the second and third quarters of 2020 in response to low crude oil prices as a result of the COVID-19 pandemic. Through our capital program in 2020, we added 16.7 MMBOE of gross proved plus probable reserves, replacing 50% of our 2020 production, including economic factors and technical revisions and before accounting for acquisitions and divestments. Excluding economic factors, we replaced 89% of total 2020 production and added 29.2 MMBOE of gross proved plus probable reserves.

Property and land acquisitions in 2020 totaled $10.1 million, which included minor acquisitions of leases and undeveloped land. We recorded net divestments of $6.1 million in 2020.

Subsequent to the year end, on January 25, 2021, Enerplus entered into the Purchase Agreement to acquire the outstanding equity interests of Bruin for total cash consideration of US$465 million, subject to certain purchase price adjustments. Closing of the Bruin Acquisition is expected to occur in early March 2021.

2019

Capital spending in 2019 totaled $618.9 million, including $531.7 million on our U.S. crude oil properties, $34.8 million on our Canadian crude oil properties and $49.3 million on our Marcellus natural gas assets. Through our capital program in 2019, we added 51.0 MMBOE of gross proved plus probable reserves, replacing 139% of our 2019 production, before accounting for acquisitions and divestments. In 2019, we spent $5.1 million on line fill to meet the requirements of a multi-year transportation contract that began in March 2019.

Property and land acquisitions in 2019 totaled $24.4 million and consisted primarily of undeveloped land in North Dakota. We recorded net divestments of $9.6 million related to the sale of properties in southeastern Saskatchewan with associated production of approximately 350 bbls/day.

2018

Capital spending in 2018 totaled $593.9 million, 30% higher than 2017. In 2018, we spent $474.4 million on our U.S. crude oil properties, $46.3 million on our Canadian crude oil properties, and $66.2 million on our Marcellus natural gas assets. In 2018, we added 65.7 MMBOE of gross proved plus probable reserves, replacing 194% of our 2018 production, before accounting for acquisitions and divestments.

Property and land acquisitions in 2018 totaled $25.8 million and included land acquisitions in Colorado and a property swap in North Dakota. We recorded net divestments of $6.9 million in 2018, primarily related to a property swap in North Dakota.

2021 Guidance

Our capital spending guidance range for 2021 is $335 million to $385 million, and assumes closing of the Bruin Acquisition in early March 2021.

Depletion, Depreciation and Accretion ("DD&A")

($ millions, except per BOE amounts)	2020	2019	2018
DD&A expense	$ 293.2	$ 356.8	$ 304.3
Per BOE	$ 8.83	$ 9.68	$ 8.94

DD&A of PP&E is recognized using the unit of production method based on proved reserves. We recorded DD&A of $293.2 million during 2020, a decrease compared to $356.8 million in 2019, as a result of lower overall production volumes and the impact of PP&E impairments and decreased capital activity in 2020.

Impairments

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves ("Standardized Measure"), using constant prices as defined by the SEC. SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value-based measurement, but rather a prescribed accounting calculation. Impairments are non-cash and are not reversed in future periods under U.S. GAAP.

Trailing twelve month average crude oil and natural gas prices declined throughout 2020. For the twelve months ended December 31, 2020, we recorded a non-cash PP&E impairment of $994.8 million (Canadian cost centre: $134.4 million, U.S. cost centre: $860.4 million). There were no impairments recorded in 2019 and 2018.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the upcoming year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill" in this MD&A.

The following table outlines the twelve-month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2020, 2019 and 2018:

Year	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US/CDN
2020	$ 39.54	$ 45.56	$ 2.00	1.34
2019	$ 55.85	$ 66.73	$ 2.58	1.33
2018	$ 65.56	$ 69.58	$ 3.10	1.28

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost less impairment and is not amortized or deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down the reporting unit's fair value, with an offsetting non-cash charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.

During 2020, we recorded a non-cash goodwill impairment of $202.8 million related to our U.S. reporting unit. The impairment was a result of the deterioration in macroeconomic conditions and low commodity prices due to the COVID-19 pandemic, which resulted in a reduction in fair value of the U.S. reporting unit and a full write down of our U.S. goodwill asset. In 2019, we recorded a non-cash goodwill impairment of $451.1 million representing the full value of the goodwill attributable to our Canadian reporting unit. At December 31, 2020, there was no goodwill remaining on our Condensed Consolidated Balance Sheet.

Asset Retirement Obligation

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $130.2 million at December 31, 2020, compared to $138.0 million at December 31, 2019. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2020, we spent $17.7 million (2019 – $16.7 million) on our asset retirement obligations and we expect to spend approximately $16.5 million in 2021. The majority of our abandonment, reclamation and remediation costs are expected to be incurred between 2024 and 2046. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment, reclamation and remediation costs are anticipated to be funded out of adjusted funds flow and our bank credit facility.

Leases

Enerplus recognizes Right-Of-Use ("ROU") assets and lease liabilities on the Consolidated Balance Sheet for qualifying leases with a term greater than 12 months. We incur lease payments related to office space, drilling rig commitments, vehicles and other equipment. Total lease liabilities included on our balance sheet are based on the present value of lease payments over the lease term. Total ROU assets included on our balance sheet represent our right to use an underlying asset for the lease term. At December 31, 2020, our total lease liability was $36.8 million compared to $53.1 million at December 31, 2019. The decrease was largely due to terminated contracts during 2020. At December 31, 2020, our ROU asset was $32.9 million, which equates to our lease liabilities less lease incentives. See Note 9 to the Consolidated Financial Statements for further details.

Income Taxes

($ millions)	2020	2019	2018
Current tax expense/(recovery)	$ (14.6)	$ (33.4)	$ (27.1)
Deferred tax expense/(recovery)	(246.2)	81.3	130.3
Total tax expense/(recovery)	$ (260.8)	$ 47.9	$ 103.2

In 2020, we recorded a current tax recovery of $14.6 million compared to $33.4 million in 2019 and $27.1 million in 2018. The recovery in 2020 related primarily to the recognition of our final U.S. Alternative Minimum Tax ("AMT") refund. The recovery in 2019 was related to the favorable settlement of a tax dispute in Canada of $13.9 million and the reclassification of the AMT refund of $13.9 million. The recovery in 2018 was primarily related to the AMT refund reclassification of $27.2 million.

In 2020, we recorded a deferred income tax recovery of $246.2 million compared to expenses of $81.3 million in 2019 and $130.3 million in 2018. The recovery in 2020 is primarily due to lower income in 2020 from non-cash PP&E impairments in both our Canadian and U.S. cost centres. The deferred tax expense in 2019 included a $22.7 million expense from the remeasurement of our net Canadian deferred income tax assets for the change in the Alberta corporate income tax rate from 12% to 8%.

Each period, we assess the recoverability of our deferred tax assets to determine whether it is more likely than not all or a portion of our deferred tax assets will not be realized. In making that assessment, we consider the available positive and negative evidence including future taxable income and reversing existing temporary differences. We have evaluated the overall net deferred income tax asset and concluded that it is more likely than not that our non-capital Canadian deferred income tax assets will be realized as there is sufficient future taxable income to realize the benefit. As a result, for 2020 we have recovered the valuation allowance previously recorded against the Canadian deferred income tax assets. Our remaining valuation allowance is primarily related to our capital loss carryforward balance. We do not anticipate future capital gains that will allow us to utilize these losses. No valuation allowance was recorded against our U.S. deferred income tax assets. This assessment is primarily the result of projecting future taxable income using total proved and probable reserves at forecast average prices and costs. There is risk of further valuation allowance in future periods if commodity prices weaken or other evidence indicates more of our deferred income tax assets will not be realized. After recording the valuation allowance recovery, our overall net deferred income tax asset was $607.0 million as at December 31, 2020 (December 31, 2019 - $372.5 million).

Our estimated tax pools at December 31, 2020 are as follows:

Pool Type ($ millions)	2020
Canada	
Canadian oil and gas property expense	$ 8
Canadian development expense	117
Canadian exploration expense	238
Undepreciated capital costs	170
Non-capital losses and other credits	294
	827
U.S.	
Net operating losses and other credits	$ 1,203
Depletable and depreciable assets	775
	1,978
Total tax pools and credits	$ 2,805
Capital losses	$ 1,053

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges (“adjusted EBITDA”) ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2020, our senior debt to adjusted EBITDA ratio was 1.4x and our net debt to adjusted funds flow ratio increased to 1.0x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity. Refer to the definitions and footnotes below.

Total debt net of cash at December 31, 2020 decreased to $376.0 million, compared to $455.0 million at December 31, 2019. Total debt was comprised of $490.4 million in senior notes less $114.5 million in cash. During the year we made scheduled repayments of US$81.6 million on our 2009 and 2012 senior notes using cash on hand. Our next scheduled senior note repayments of US$59.6 million and US$22.0 million are due in May and June 2021, respectively, with remaining maturities extending to 2026. At December 31, 2020, we were undrawn on our US$600 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 90% for 2020 compared to 93% in 2019.

Our working capital deficiency, excluding cash and cash equivalents and current derivative financial assets and liabilities, increased to $257.8 million at December 31, 2020 from $210.4 million at December 31, 2019 due to a reduction in accrued revenues as a result of lower production and realized commodity prices and the receipt of the remaining AMT refunds. Our working capital varies primarily due to the timing of the cash realization of our current assets and current liabilities, and the current level of business activity, including our capital spending program, along with commodity price volatility. We expect to finance our working capital deficit and ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under “Commitments”.

During 2020, a total of $29.2 million was returned to shareholders through the repurchase of 340,434 common shares under our Normal Course Issuer Bid (“NCIB”) at an average price of $7.44 per share and dividend payments of $26.7 million. In comparison, we returned a total of $206.5 million to shareholders in 2019 through the repurchase of 18,231,401 common shares under the NCIB at an average price of $9.80 per share and dividend payments of $27.7 million. We expect to continue to pay monthly dividends to our shareholders of $0.01 per share in 2021; however, if economic conditions change, we may make adjustments.

On January 25, 2021, Enerplus entered into the Purchase Agreement to acquire all the outstanding equity interests of Bruin for total cash consideration of US$465 million, subject to certain purchase price adjustments. Enerplus will not assume any debt of Bruin as a part of the Bruin Acquisition, which is expected to close in early March 2021.

We intend to fund a portion of the purchase price of the Bruin Acquisition with a new three-year, senior unsecured US$400 million Term Facility. The Term Facility will include financial and other covenants and pricing consistent with Enerplus' existing US$600 million revolving credit facility, which matures October 31, 2023. Funding under the Term Facility is subject to limited conditions, including completion of the Bruin Acquisition and delivery of customary credit facility documentation. Following the announcement of the Bruin Acquisition, Enerplus completed a bought deal equity financing, issuing 33.1 million common shares at a price of $4.00 per share for gross proceeds of $132.3 million ($126.2 million, net of issuance costs). The net proceeds will be used to fund the remainder of the purchase price. We expect to be undrawn on our US$600 million credit facility upon close of the Bruin Acquisition.

At December 31, 2020, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants at December 31, 2020:

Covenant Description		December 31, 2020
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)	3.5x	1.4x
Total debt to adjusted EBITDA(1)	4.0x	1.4x
Total debt to capitalization	55%	24%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)(2)	3.0x – 3.5x	1.4x
Senior debt to consolidated present value of total proved reserves(3)	60%	29%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	13.2x

Definitions

“Senior Debt” is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.

“Adjusted EBITDA” is calculated as net income less interest, taxes, depletion, depreciation, amortization, and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended December 31, 2020 were $96.4 million and $373.1 million, respectively.

“Total Debt” is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

“Capitalization” is calculated as the sum of total debt and shareholder’s equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

(1) See “Non-GAAP Measures” in this MD&A for a reconciliation of adjusted EBITDA to net income.

(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Counterparty Credit

CRUDE OIL AND NATURAL GAS SALES COUNTERPARTIES

Our crude oil and natural gas receivables are with customers in the crude oil and gas industry and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted, we obtain financial assurances such as letters of credit, parental guarantees or third-party insurance to mitigate a portion of our credit risk. This process is utilized for both our crude oil and natural gas sales counterparties as well as our financial derivative counterparties.

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. All of our derivative counterparties are considered investment grade. At December 31, 2020, we had $3.6 million in financial derivative assets offset by $19.3 million of financial derivative liabilities resulting in a net liability position of $15.7 million.

Dividends

($ millions, except per share amounts)	2020	2019	2018
Cash dividends(1)	$ 26.7	$ 27.7	$ 29.3
Per weighted average share (Basic)	$ 0.12	$ 0.12	$ 0.12

(1) Excludes changes in non-cash financing working capital. See Note 18(b) of the Consolidated Financial Statements for additional information.

We reported total dividends of $26.7 million or $0.12 per share to our shareholders in 2020. During 2019 and 2018, we reported total dividends of $27.7 million or $0.12 per share and $29.3 million or $0.12 per share, respectively.

The dividend is part of our strategy to return capital to our shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2020	2019	2018
Share capital ($ millions)	$ 3,097.0	$ 3,088.1	$ 3,337.6
Common shares outstanding (thousands)	222,548	221,744	239,411
Weighted average shares outstanding – basic (thousands)	222,503	231,334	244,076
Weighted average shares outstanding – diluted (thousands)	222,503	231,334	247,261

For the twelve months ended December 31, 2020, a total of 2,044,718 units vested pursuant to our treasury settled LTI plans (2019 – 1,007,234; 2018 – 2,539,498). In total, 1,160,000 common shares were issued from treasury and $13.8 million was transferred from paid-in capital to share capital (2019 – 564,000 and $4.4 million; 2018 – 2,539,498 and $23.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2020 – $7.2 million, 2019 – $5.0 million; 2018 - nil). During 2020, no common shares were issued pursuant to our stock option plan (2019 – nil; 2018 – 668,000 common shares for $9.1 million).

During the twelve months ended December 31, 2020, we repurchased 340,434 common shares under the previous NCIB at an average price of $7.44 per share, for total consideration of $2.5 million (2019 – 18,231,401, $178.8 million; 2018 – 5,925,084, $79.0 million). Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit (2019 – $253.9 million; $75.1 million; 2018 – $82.6 million and $3.6 million). We chose not to renew our NCIB after its expiry on March 25, 2020 in order to preserve capital and maintain our balance sheet strength.

Subsequent to December 31, 2020, on February 3, 2021, Enerplus issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million ($126.2 million net of issue costs) pursuant to a bought deal prospectus offering under its base shelf prospectus.

As of February 18, 2021, we had 256,235,100 common shares outstanding. In addition, an aggregate of 5,475,625 common shares may be issued to settle outstanding grants under our share award incentive plan (in the form of PSUs and RSUs), assuming the maximum payout multiplier of 2.0 times for the PSUs. For further details see Note 14 to the Financial Statements.

Commitments

We have the following minimum annual contractual commitments:

($ millions)	Total	Minimum Annual Commitment Each Year 2021	2022	2023	2024	2025	Total Committed after 2025
Senior notes[1]	$ 490.4	$ 103.8	$ 128.0	$ 102.6	$ 102.6	$ 26.7	$ 26.7
Transportation commitments[2]	290.0	44.5	30.4	29.4	29.1	29.1	127.5
Processing commitments	9.5	1.6	1.5	1.5	1.5	1.5	1.9
Operating lease obligations	40.0	14.6	8.3	7.0	6.2	1.2	2.7
Total commitments[3]	$ 829.9	$ 164.5	$ 168.2	$ 140.5	$ 139.4	$ 58.5	$ 158.8

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2020 foreign exchange rate of 1.27.

In the Marcellus, we have firm transportation agreements in place for approximately 68,000 Mcf/day of natural gas, which expire between 2022 and 2036. This includes an agreement for firm pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections for 30,000 Mcf/day of natural gas until mid-2027, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of US$76.6 million through 2036. In the Bakken region, we hold firm pipeline capacity to transport a portion of our crude oil production to the U.S. Gulf Coast, which expires in early 2029.

In Canada, we have various firm transportation agreements for approximately 1,800 BOE/day of our crude oil and natural gas liquids production in 2021, decreasing to approximately 820 BOE/day on average from 2022 to 2027. We have firm natural gas liquids fractionation contracts for 1,125 bbls/day through 2027, and firm natural gas transportation contracts for approximately 30,000 Mcf/day as of December 31, 2020.

Our commitments and contingencies are more fully described in Note 16 to the Financial Statements. Our operating lease obligations are detailed in Note 9 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Year ended December 31, 2020 Canada	U.S.	Total	Year ended December 31, 2019 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,178	38,243	45,421	8,625	41,079	49,704
Natural gas liquids (bbls/day)	628	5,005	5,633	895	4,034	4,929
Natural gas (Mcf/day)	12,481	225,376	237,857	23,706	254,745	278,451
Total average daily production (BOE/day)	9,886	80,811	90,697	13,471	87,571	101,042
Pricing[2]						
Crude oil (per bbl)	$ 36.14	$ 45.89	$ 44.35	$ 59.71	$ 70.92	$ 68.98
Natural gas liquids (per bbl)	21.32	8.90	10.29	28.82	12.16	15.19
Natural gas (per Mcf)	2.59	1.83	1.87	2.42	2.91	2.87
Capital Expenditures						
Capital spending	$ 23.4	$ 268.0	$ 291.4	$ 37.9	$ 581.0	$ 618.9
Acquisitions	2.6	7.5	10.1	6.0	18.4	24.4
Divestments	0.1	(6.2)	(6.1)	(9.0)	(0.6)	(9.6)
Netback[3] Before Hedging						
Crude oil and natural gas sales	$ 113.6	$ 809.9	$ 923.5	$ 220.8	$ 1,352.1	$ 1,572.9
Royalties	(17.1)	(169.2)	(186.3)	(43.5)	(274.6)	(318.1)
Production taxes	(1.1)	(48.8)	(49.9)	(2.6)	(80.5)	(83.1)
Operating expenses	(55.9)	(207.7)	(263.6)	(72.1)	(218.7)	(290.8)
Transportation costs	(8.7)	(123.7)	(132.4)	(10.1)	(134.8)	(144.9)
Netback before hedging	$ 30.8	$ 260.5	$ 291.3	$ 92.5	$ 643.5	$ 736.0
Other Expenses						
Asset impairment	$ 134.4	$ 860.4	$ 994.8	$ —	$ —	$ —
Goodwill impairment	202.8	—	202.8	451.1	—	451.1
Commodity derivative instruments loss/(gain)	(108.8)	—	(108.8)	66.1	—	66.1
General and administrative expense[4]	2.3	55.3	57.6	29.0	43.8	72.8
Current income tax expense/(recovery)	—	(14.5)	(14.5)	(13.9)	(19.5)	(33.4)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2020	2019	2018
Crude oil and natural gas sales, net of royalties	$ 737.2	$ 1,254.8	$ 1,292.7
Net income/(loss)	(923.4)	(259.7)	378.3
Per share (Basic)	(4.15)	(1.12)	1.55
Per share (Diluted)	(4.15)	(1.12)	1.53
Adjusted net income[1]	19.8	243.2	344.8
Cash flow from operating activities	446.4	694.2	738.8
Adjusted funds flow[1]	358.2	709.0	753.5
Cash dividends[2]	26.7	27.7	29.3
Per share (Basic)[2]	0.12	0.12	0.12
Total assets	1,466.5	2,565.8	3,118.3
Total debt	490.4	606.5	696.8
Total debt net of cash[1]	376.0	455.0	333.5

(1) See “Non-GAAP Measures” section of this MD&A.
(2) Calculated based on dividends paid or payable.

2020 versus 2019

Oil and natural gas sales, net of royalties, were $737.2 million in 2020 compared to $1,254.8 million in 2019 due to lower realized commodity prices and decreased production in 2020.

We reported a net loss of $923.4 million in 2020 compared to a net loss of $259.7 million in 2019. The decrease in 2020 was primarily due to a $994.8 million non-cash PP&E impairment and a $202.8 million non-cash U.S. goodwill impairment.

Cash flow from operating activities and adjusted funds flow decreased to $446.4 million and $358.2 million, respectively, in 2020 from $694.2 million and $709.0 million in 2019. The decrease was primarily the result of a $517.6 million decrease in net crude oil and natural gas sales due to lower realized commodity prices and lower production, partially offset by a $115.6 million increase in realized commodity derivative gains.

2019 versus 2018

Oil and natural gas sales, net of royalties, were $1,254.8 million in 2019 compared to $1,292.7 million in 2018, with the impact of higher production more than offset by lower commodity prices.

We reported a net loss of $259.7 million in 2019 compared to net income of $378.3 million in 2018. The decrease in 2019 was primarily due to a $451.1 million non-cash Canadian goodwill impairment, along with losses on commodity derivative instruments.

Cash flow from operations and adjusted funds flow decreased to $694.2 million and $709.0 million, respectively, from $738.8 million and $753.5 million, respectively, in 2018. Crude oil and natural gas sales decreased due to lower realized commodity prices, while operating expenses increased over the same period, in part due to higher liquids volumes. These decreases were offset by realized commodity derivative gains in 2019 compared to losses in 2018.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2020				
Fourth Quarter	$ 195.1	$ (204.2)	$ (0.92)	$ (0.92)
Third Quarter	191.9	(112.8)	(0.51)	(0.51)
Second Quarter	122.1	(609.3)	(2.74)	(2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	$ 737.2	$ (923.4)	$ (4.15)	$ (4.15)
2019				
Fourth Quarter	$ 327.0	$ (429.1)	$ (1.93)	$ (1.93)
Third Quarter	318.9	65.1	0.28	0.28
Second Quarter	321.4	85.1	0.36	0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 1,254.8	$ (259.7)	$ (1.12)	$ (1.12)

Crude oil and natural gas sales, net of royalties, decreased in 2020 compared to 2019 due to lower realized commodity prices, and decreased production. We reported a net loss in 2020 due to a non-cash goodwill impairment of $202.8 million on our U.S. reporting unit and a non-cash PP&E impairment of $994.8 million recorded in the twelve months ended December 31, 2020.

During 2019, we reported crude oil and gas sales, net of royalties, of $1,254.8 million. We reported a net loss in 2019 due to a non-cash impairment of $451.1 million on our Canadian goodwill asset recorded in the fourth quarter.

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

Enerplus believes that minimizing the environmental impacts of its operations is a foundational tenet of corporate responsibility. Moreover, as the global economy transitions to a lower carbon future, climate related policies and regulations around carbon emissions are becoming increasingly stringent, requiring businesses to adapt to support long-term business resilience. We intend to continue to improve energy efficiencies and proactively manage our environmental impact in compliance with applicable government regulations, including regulations enacted at the provincial, state and federal jurisdictions in which we operate.

Our Board of Directors is responsible for overseeing our ESG initiatives. Specific accountability for our six material focus areas have been mapped to the relevant Board subcommittees, including the Compensation and Human Resources Committee, the Safety and Social Responsibility Committee (the "S&SR Committee") and the Corporate Governance and Nominating Committee. The six material focus areas are:

- Greenhouse Gas ("GHG") Emissions
- Water Management
- Culture
- Community Engagement
- Health and Safety
- Board Constitution and Culture

As part of our continued integration of ESG issues into our business strategy and operations, early in 2020 we established targets for reducing GHG emissions intensity and freshwater use. Using 2019 as a baseline, we targeted a 10% reduction of our scope 1 and 2 GHG emissions per BOE in 2020. Based on preliminary estimates, we expect to have reduced our 2020 GHG emissions intensity by more than 20% compared to 2019. Finalized emissions will be available in our annual ESG Report and Data Tables, expected to be published later in 2021.

In 2020, we targeted a reduction in freshwater use per well completion in North Dakota by 15%, compared to 2019. We ended 2020 using, on average, 23% less freshwater per well completion in North Dakota, compared to 2019.

We set a Health & Safety target of reducing our Lost Time Injury Frequency (LTIF) by 25%, on average, from 2020 to 2023, relative to a 2019 baseline. In 2020, we reported an LTIF of 0.08 injuries per 200,000 worker hours, a 67% improvement from 2019. We will continue to update the market as we progress closer to the end of our 2023 target. We are pleased to announce our 2020 LTIF was the best safety performance in our organization's history.

We expect to integrate the assets acquired through the Bruin Acquisition into our existing ESG strategy throughout 2021. More information will be available with the publication of our 2021 ESG Report later in the year.

We have a Health & Safety Policy ("H&S Policy") and an Environmental, Social and Governance Policy ("ESG Policy"), which articulate our commitment to health and safety, community engagement, environmental and regulatory compliance, and social and governance practices. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with these policies. The S&SR Committee of our Board of Directors is responsible for overseeing our H&S performance. The Board of Directors are responsible for overseeing our ESG performance and strategy. This ensures there are adequate systems in place to support ongoing compliance, and to plan the Company's activities in a safe, socially responsible and sustainable manner.

The S&SR Committee regularly reviews health, safety, environmental and regulatory updates, and risks. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and we have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations. However, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements.

Annually, we publish an ESG Report in accordance with the Sustainability Accounting Standards Boards (SASB) materiality metrics, the Global Reporting Initiative (GRI) Core option, and the International Petroleum Industry Environmental Conservation Association's ("IPIECA") "Oil and gas industry guidance on voluntary sustainability reporting" (a joint publication with the American Petroleum Institute and the International Association of Oil & Gas Producers). The report summarizes our environmental, safety, social responsibility and governance performance, and can be found on our website at www.enerplus.com.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Crude Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for crude oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, valuation allowance on deferred income tax assets, gain or loss calculations and purchase equations. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous estimates and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

Under the full cost method of accounting for PP&E, we are subject to quarterly calculations of a ceiling or limitation on the amount of our crude oil and natural gas properties that can be capitalized on our balance sheet by cost centre. If the net capitalized costs of our crude oil and natural gas properties exceed the cost centre ceiling, we are subject to a ceiling test write-down to the extent of such excess. These write-downs reduce net income and impact shareholders' equity in the period of occurrence and result in lower depletion expense in future periods. The volume and discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of crude oil and natural gas that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average crude oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of our crude oil and natural gas properties could occur in the future. Under U.S. GAAP impairments are not reversed in future periods.

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net assets acquired. Goodwill is allocated to reporting units and is assessed for impairment at least annually. To assess impairment, the Company first evaluates qualitative factors, such as industry and market considerations and overall financial performance, to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value including goodwill, a quantitative impairment test is performed. If the carrying amount of the reporting unit exceeds its related fair value, goodwill is written down to the reporting unit's fair value. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates. At December 31, 2020, there was no goodwill remaining on our Condensed Consolidated Balance Sheet.

Income Taxes

Management makes certain estimates in calculating deferred tax assets and liabilities, as well as income tax expense. These estimates often involve judgment regarding differences in the timing and recognition of revenue and expense for tax and financial reporting purposes as well as the tax basis of our assets and liabilities at the balance sheet date before tax returns are completed. Additionally, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. We must record a valuation allowance against a deferred tax asset where all or a portion of that asset is not expected to be realized. In evaluating whether a valuation allowance should be applied, we consider evidence such as future taxable income, among other factors, both positive and negative. This determination involves numerous judgments and assumptions and includes estimating factors such as commodity prices, production and other operating conditions. If any of those factors, assumptions or judgments change, the deferred tax asset could change, and in particular decrease in a period where we determine it is more likely than not that the asset will not be realized. Alternatively, a valuation allowance may be reversed where it is determined it is more likely than not that the asset will be realized.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon, reclaim and remediate its ownership interest in all wells, facilities and pipelines and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and depleted over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserves estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair value of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we, and independent evaluators, estimate crude oil and natural gas reserves and future prices of crude oil and natural gas.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2(p) in our Financial Statements for Standards and Interpretations that were issued but not yet effective at December 31, 2020.

RISK FACTORS AND RISK MANAGEMENT

Risks Relating to the Impact of the COVID-19 Pandemic and Continued Weakness and Volatility in Commodity Prices

The global outbreak of the COVID-19 pandemic and the ongoing uncertainty as to the extent and duration of this pandemic, as well as governmental authorities response thereto, has resulted in, and continues to result in, among other things: increased volatility in financial markets, including credit markets and foreign currency and interest exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions, quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, the COVID-19 pandemic has resulted in, and continues to result in, a reduction in the demand for crude oil and natural gas.

In addition, recent market events and conditions, including excess global crude oil and natural gas supply and decreased global demand due to the COVID-19 pandemic, have caused significant weakness and volatility in commodity prices. While the commodity prices began to stabilize as global economies began to re-open, the recent resurgence of COVID-19 cases in certain geographic areas, and the possibility that a resurgence may occur in other areas, has resulted in the re-imposition of certain restrictions noted above by local authorities. This further increases the risk and uncertainty as to the extent and duration of the COVID-19 pandemic and the resultant impact on commodity demand and prices. The overall result of these recent events and conditions could lead to a prolonged period of depressed prices for crude oil and natural gas which may result in further curtailments, voluntary or otherwise. We are continuing to evaluate the impact of the COVID-19 pandemic and the continued commodity environment instability on our business, financial condition and results of operations; however, the full extent of such impact continues to be unknown at this time and will depend on future developments (which are highly uncertain and cannot be predicted with any degree of confidence) and may be adverse and could result, among other things, in PP&E or deferred tax asset impairment, or exceeding our debt covenants, among others. See disclosure under "Impairment – PP&E", "Income Taxes" and "Liquidity and Capital Resources" in this MD&A.

We are also subject to risks relating to the health and safety of our personnel, including the potential for a slowdown or temporary suspension of our operations in locations impacted by an outbreak or further regulatory changes. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would negatively impact our production volumes, which could adversely impact our business, financial condition and results of operations.

Depending on the extent and duration of the COVID-19 pandemic, it may also have the effect of heightening many of the other risks described in the Annual Information Form and the Annual MD&A.

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and natural gas liquids, actions taken by OPEC or non-OPEC members to set, maintain or alter production levels to help in achieving a balanced market, geopolitical uncertainty, sustained pandemics, including the COVID-19 pandemic, or epidemics that disrupt economies, whether local or global, impacting supply, demand and prices for crude oil, natural gas liquids and natural gas, economic conditions including currency fluctuations, global gross domestic product growth, weather conditions, the level of consumer demand, the ability to export oil and liquefied natural gas and natural gas liquids from North America and the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American crude oil, natural gas and natural gas liquids, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the effect of world-wide energy conservation and greenhouse gas reduction measures, the price and availability of alternative fuels and existing and proposed changes to government regulations and policy decisions, including moratoriums with respect thereto.

A future decline in crude oil or natural gas prices may have a material adverse effect on our operations and cash flows, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of our crude oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting our production volumes, or our desire to market our production in unsatisfactory market conditions. Furthermore, we may be subject to the decisions of third party operators or to legislative decisions by regional governments who, independently and using different economic parameters, may decide to curtail or shut-in jointly owned production or to mandate industry-wide production curtailments.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of crude oil, natural gas liquids, and natural gas price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 18, 2021, we have hedged approximately 21,500 bbls/day and 17,000 bbls/day, respectively, of our expected crude oil production for 2021 and 2022, 60,000 Mcf/day of natural gas production for March 2021 and 100,000 Mcf/day of natural gas production for April 1 to October 31, 2021, at price levels disclosed in the "Price Risk Management" section above. Refer to the "Price Risk Management" section for further details on our price risk management program.

Risks Relating to Climate Change

Enerplus is subject to climate change related risks which are generally grouped into two categories: physical risks and transition risks. Physical risks include the impact that a change in climate could have on our operations, including limited water availability, severe weather or fire. These events may increase the cost of water, energy, insurance or capital projects, impacting our profitability. The physical risks of climate change may also result in operational delays, depending on the nature of the event. Enerplus does not believe that its current or near-term operations expose it to any particular physical risks which differ from those facing a typical North American onshore oil and gas producer, and currently cannot predict or quantify the potential financial impact of any such risks.

Transition risk is broader and relates to the consequences of a global transition to reduced carbon, including the risk of regulatory and policy change and reputational concerns. The growing push for decarbonization increases the risk of potentially burdensome regulatory and/or policy changes that could increase Enerplus' risk in obtaining access to service providers, including but not limited to debt holders, insurers, and the investment community. In addition, Enerplus could also have stranded assets, i.e. be unable to obtain value for, or from, its reserves. More specific concerns of the fossil fuels, industry relate to GHG emissions, as well as water and land use, could also result in more stringent legislation, including requirements to significantly reduce GHG emissions, water consumption or setback requirements for facilities and wells, all of which could be costly to implement. For example, on January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the U.S. federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across agencies and economic sectors. Failure to comply with such regulations and laws could also result in significant penalties being imposed. In addition, a potential increase in capital expenditures, operating expenses, abandonment and reclamation obligations and distribution costs or the loss of operating licenses, any of which may not be recoverable in the marketplace, could result in operations or growth projects becoming less profitable, uneconomic, or result in the Enerplus' inability to continue development of assets. Additionally, there is a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector; both the Bank of Canada and the Federal Reserve of the United States have joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector.

There is also a reputational risk associated with climate change, which considers the public perception of Enerplus' role in the transition to a low carbon economy. We seek to mitigate this risk through a strong ESG program with six material focus areas which are overseen by the Company's Board of Directors and applicable Board subcommittees. Our strategy is to be a "best in basin" operator – in the eyes of our shareholders, employees, contractors, regulators, communities and the general public. Despite these efforts, activities undertaken directly by Enerplus or its employees, or by others in industry, could adversely affect Enerplus' reputation. If the reputation of the Corporation, or the oil and gas industry in general, is diminished, it could result in: the loss of employees or revenue; delays in regulatory approvals; increased operating, capital, financing and regulatory costs; reduced shareholder confidence and negative stock price movement.

Regulatory Risk and Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we operate under federal, provincial, state, tribal and municipal legislation and regulation that govern such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income taxes and the exportation of crude oil, natural gas and other products. We may be required to apply for regulatory approvals in the ordinary course of business. To the extent that we fail to comply with applicable government regulations or regulatory approvals, we may be subject to compliance and enforcement actions that are either remedial or punitive to deter future noncompliance. Such actions include fines or fees, notices of noncompliance, warnings, orders, curtailment, administrative sanctions and prosecution.

Government regulations may be changed from time to time in response to economic, political or socioeconomic conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. U.S. federal and state and Canadian federal and provincial continue to scrutinize emissions, as well as the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry; certain states have called for bans on oil and gas drilling using hydraulic fracturing and the new U.S. administration has taken actions towards fulfilling its initiative of curtailing hydraulic fracturing of federal lands. Additionally, various levels of U.S. and Canadian governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds ("VOC") and methane gas emissions.

The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations could negatively impact the development of crude oil and natural gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies including taxes, fees or other penalties.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results. Accordingly, while we continue to prepare to meet the potential requirements at each of the provincial, state and federal levels, the actual cost impact and its materiality to our business remains uncertain.

Anticipated Benefits of Acquisitions or Divestments

From time to time, we may acquire additional crude oil and natural gas properties and related assets. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures, and personnel in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities from combining and integrating the acquired assets and properties into our existing business. These activities will require the dedication of substantial management effort, time, capital, and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during this process. The risk factors specified in this MD&A relating to the crude oil and natural gas business and our operations, reserves and resources apply equally to future properties or assets that we may acquire. We conduct due diligence in connection with acquisitions, but there is no assurance that we will identify all the potential risks and liabilities related to such properties.

When acquiring assets, we are subject to inherent risks associated with predicting the future performance of those assets. We may make certain estimates and assumptions respecting the characteristics of the assets we acquire, that may not be realized over time. As such, assets acquired may not possess the value we attribute to them, which could adversely impact our future cash flows. To the extent that we make acquisitions with higher growth potential, the higher risks often associated may result in increased chances that actual results may vary from our initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches, and assumptions than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments. There is also no assurance that the acquired assets will be viewed favourably by our investors and could result in a negative effect to the price of our common shares.

Certain acquisitions, and in particular acquisitions of higher risk/higher growth assets and the development of those acquired assets, may require capital expenditures and we may not receive cash flow from operating activities from these acquisitions for several years, or in amounts less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect our cash flow.

The closing of the Bruin Acquisition is subject to satisfaction of certain closing conditions. There is no certainty, nor can we provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. If the Bruin Acquisition is not completed as contemplated, Enerplus could suffer adverse consequences, including the loss of investor confidence. If the Bruin Acquisition is completed, there is a risk that some or all of the expected benefits of the Bruin Acquisition may fail to materialize, may cost more to achieve or may not occur within the time periods we anticipate.

We may also seek to divest of properties and assets from time to time. These divestments may consist of non-core properties or assets, or may consist of assets or properties that are being monetized to fund alternative projects or development or debt repayments. There can be no assurance that we will be successful, that we will realize the amount of desired proceeds, or that such divestments will be viewed positively by the financial markets. Divestments may negatively affect our results of operations or the trading price of our common shares. In addition, although divestments typically transfer future obligations to the buyer, we may not be exempt from certain future obligations, including abandonment, reclamation, and/or remediation if applicable, which may have an adverse effect on our operations and financial condition.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time, as well as investors' view of the oil and gas industry overall. We may not be able to access the capital markets in the future on terms favorable to us, or at all. Our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

We are required to assess our foreign private issuer ("FPI") status under U.S. securities laws on an annual basis. If we lose our FPI status, we may have restricted access to capital markets for a period of time until the required approvals are in place from the SEC.

Access to Transportation and Processing Capacity

Market access for crude oil, natural gas liquids and natural gas production in the U.S. and Canada is dependent on our ability, and the ability of our buyers as applicable, to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. As production increases in the regions where we operate, it is possible production may exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions where government or other third parties could limit or ban the shipping of commodities by truck, pipeline or rail. Special interest groups and/or social instability could also prevent access to leased land or continue their opposition to infrastructure development, at either the regulatory or judicial level, including the ongoing matters with respect to DAPL (which are before the District Court for the District of Columbia), resulting in operational delays, or even the cancellation of construction of the required infrastructure, or the shutdown of already operating infrastructure projects, further impeding our ability to operate, produce and market our products. Additionally, the transportation of crude oil by rail has been under closer scrutiny by government regulatory agencies in Canada and the U.S. over the past few years. As a result, transporting crude oil by rail may carry a higher cost versus traditional pipeline infrastructure or other means of transporting production.

We monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate transportation and processing risk by contracting for firm pipeline or processing capacity or using other means of transportation, including trucking or selling to third parties that have access to pipeline or rail capacity.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation, government regulation or third party operational practices, it could result in a reduction to cash flow and production levels and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. Combined with the ongoing volatility in commodity prices, any shortage in pipeline infrastructure in producing regions where we operate may result in discounted prices and an ongoing risk of price-related production curtailments.

The recent changes in control of the U.S. Congress and the election of President Biden may result in legislative and regulatory changes that could have an adverse effect on Enerplus. In particular, President Biden has indicated that his administration will seek to curtail oil and gas development on federal lands, possibly through temporary or permanent bans on new leasing, delays or bans on the issuance of drilling permits, and his administration may pursue other regulatory initiatives, executive actions and legislation in support of his regulatory agenda. Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs, decrease U.S. demand for our products, or otherwise negatively impact Enerplus, which may have a material adverse effect on our business, financial condition and operations.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of proppant, pumper services, and operating costs such as electricity, chemicals, supplies, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our current capital and operating costs protected with existing agreements, changing regulatory conditions, such as potential new or revised regulations in the U.S. requiring certain raw materials, such as steel, for use on certain projects to be sourced from the U.S., or that goods and/or services be procured from specific vendors or classes of vendors on certain projects, may result in higher than expected supply costs for the company.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserves or resources write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluate or audit the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 98% of the total proved plus probable net present value (discounted at 10% and using NI 51-101 standards) of our reserves at December 31, 2020. McDaniel & Associates Consultants Ltd. (“McDaniel”) evaluated 86% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. (“NSAI”) evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluation of best estimate development pending contingent resources associated with our North Dakota assets was conducted by Enerplus’ qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

The Reserves Committee of the Board of Directors and the Board of Directors has reviewed and approved the reserves and resources reports of the independent evaluators.

Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets

Under U.S. GAAP, the net capitalized cost of crude oil and natural gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer’s reporting date. The amount by which the net capitalized costs exceed the discounted value will be charged to net income.

Under U.S. GAAP, the net deferred tax asset is limited to the estimate of future taxable income resulting from existing properties. We estimate future taxable income based on before-tax future net revenue from proved plus probable reserves, undiscounted, using forecast prices, and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income, however these amounts can be reversed in future periods if future taxable income increases.

We recorded an impairment of $994.8 million (Canadian cost centre: $134.4 million, U.S. cost centre $860.4 million) on our crude oil and natural gas assets in 2020. There were no crude oil and natural gas assets impairments recorded in 2019 and 2018. In 2020, we reversed our valuation allowance of $13.9 million recorded in 2019 against a portion of our Canadian deferred income tax asset, as projected future taxable income in Canada was sufficient to recognize these assets. No valuation allowance was recorded against our U.S. deferred income tax asset. There is a risk of impairment on our oil and gas properties, deferred tax asset and goodwill if commodity prices weaken, costs increase, or if there is a downward revision to reserves. Please refer to the “Impairments” and “Income Taxes” sections of the MD&A and Notes 5 and 13 of the Financial Statements for further details.

Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may change in a manner that adversely affects us or our security holders. Canadian, U.S. and foreign tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.

Counterparty and Joint Venture Credit Exposure

We are subject to the risk that the counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements as a result of liquidity requirements or insolvency. Low crude oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position. In addition to the usual delays in payment by purchasers of crude oil and natural gas, payments may also be delayed by, among other things: (i) capital or liquidity constraints experienced by our counterparties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) weather related delays, such as freeze-offs, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses. Any of these delays could reduce the amount of our cash flow and the payment of cash dividends to our shareholders in a given period and expose us to additional third-party credit risks.

A credit review process is in place to assess and monitor our counterparties’ credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third-party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities and, where possible, take our production in kind rather than relying on third party operators. In certain instances, we may be able to aggregate all amounts owing to each other and settle with a single net amount.

See the “Liquidity and Capital Resources” section for further information.

Debt covenants may be exceeded with no ability to negotiate covenant relief

Declines or continued volatility in crude oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead us to increase amounts drawn under our bank credit facility in order to carry out our operations and fulfill our obligations. Significant reductions to cash flow, significant increases in drawn amounts under the bank credit facility, or significant reductions to proved reserves may result in us breaching our debt covenants under the credit facility, senior notes and Term Facility. If a breach occurs, there is a risk that we may not be able to negotiate covenant relief with one or more of our lenders under the credit facility, senior notes or Term Facility. Failure to comply with debt covenants, or negotiate relief, may result in our indebtedness under the credit facility, senior notes or Term Facility becoming immediately due and payable, which may have a material adverse effect on our operations and financial condition.

The credit facility, senior notes, Term Facility and any replacement credit facility may not provide sufficient liquidity

Although we believe that our existing credit facility, senior notes and the recently added Term Facility are sufficient, there can be no assurance that the current amount will continue to be available, or will be adequate for our financial obligations, or that additional funds can be obtained as required or on terms which are economically advantageous to Enerplus. The amounts available under the credit facility, senior notes and Term Facility may not be sufficient for future operations, or we may not be able to renew our bank credit facility or Term Facility or obtain additional financing on attractive economic terms, if at all. The Term Facility matures in early 2024 (three years post-closing date of the Bruin Acquisition). The bank credit facility is generally available on a four-year term, extendable each year with a bullet payment required at the end of four years if the facility is not renewed. We renewed our bank credit facility in 2019 and it currently expires on October 31, 2023. There can be no assurance that such a renewal will be available on favourable terms or that all the current lenders under the facility will participate or renew at their current commitment levels. If this occurs, we may need to obtain alternate financing. Any failure of a member of the lending syndicate to fund its obligations under the bank credit facility or to renew its commitment in respect of such bank credit facility, or failure by Enerplus to obtain replacement financing or financing on favourable terms, may have a material adverse effect on our business and operations. In addition, dividends to shareholders may be eliminated, as repayment of debt under the credit facility, senior notes and Term Facility has priority over dividend payments to our shareholders.

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in each area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services through 2021, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Cyber Security Risks

We are subject to a variety of information technology and system risks as part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of our information technology systems by third parties or insiders. Additionally, use of personal devices can create further avenues for potential cyber-related incidents, as we have little or no control over the safety of these devices. Information technology and cyber risks have increased during the COVID-19 pandemic, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements. Although we have security measures and controls in place that are designed to mitigate these risks, a breach of our security and/or a loss of information could occur and result in business interruptions, service disruptions, financial loss, theft of intellectual property and confidential information, litigation, enhanced regulatory attention and penalties, as well as reputational damage. Furthermore, the adoption of emerging technologies, such as cloud computing, artificial intelligence and robotics, call for continued focus and investment to manage risks effectively. Not managing this risk effectively may have an adverse effect and, therefore, may increase the risk of financial or reputational loss. The significance of any such event is difficult to quantify, but may be material in certain circumstances and could have a material effect on our business, financial condition and results of operations.

Ability to Divest Properties

Regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of crude oil and natural gas properties. As a result, the potential number of parties able to acquire our non-core assets has been reduced, we may not be able to obtain full value for such assets, or transactions may involve greater risk and complexity. The Supreme Court of Canada’s decision in the Redwater Energy Corporation case may also impact our ability to transfer licenses, approvals or permits, and may result in increased costs and delays or require changes to our abandonment of projects and transactions. We also understand that further regulatory changes are being planned in Alberta and British Columbia, which may result in additional factors being considered when evaluating such transactions.

Title Defects or Litigation

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however, disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as all of our senior notes, our credit facility and our Term Facility are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements. We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However, our U.S. capital spending, transportation and operating costs, interest expense and U.S. dollar denominated debt are negatively impacted with a weak Canadian dollar.

Currently, we do not have any foreign exchange contracts in place to hedge our foreign exchange exposure. However, we continue to monitor fluctuations in foreign exchange and the impact on our operations.

Interest Rate Exposure

Movements in interest rates and credit markets may affect our borrowing costs and value of investments such as our shares as well as other equity investments.

At December 31, 2020, we were undrawn on our US$600 million bank credit facility and our debt consisted of fixed interest rate senior notes.

On January 25, 2021, we entered into the Purchase Agreement to acquire all the equity interests of Bruin for total cash consideration of US$465 million, subject to certain adjustments. On the same date, we entered into a new three-year, senior unsecured US$400 million Term Facility, to be fully drawn down on the closing date of the Bruin Acquisition to pay for a portion of the purchase price. The Term Facility includes financial and other covenants and pricing consistent with our existing US$600 million revolving credit facility, which matures October 31, 2023. Funding under the Term Facility is subject to limited conditions, including completion of the acquisition and delivery of customary credit facility documentation.

ADJUSTED FUNDS FLOW SENSITIVITY

The sensitivities below reflect all of Enerplus' commodity contracts listed in Note 15 to the Financial Statements and are based on 2021 guidance production, assuming the successful closing of the Bruin Acquisition in early March, and price levels of: WTI - US$55.00/bbl, NYMEX - US$3.00/Mcf and a USD/CDN exchange rate of 1.27. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table	Estimated Effect on 2021 Adjusted Funds Flow per Share(1)
Increase of US$5.00 per barrel in the price of WTI crude oil	$ 0.26
Decrease of US$5.00 per barrel in the price of WTI crude oil	$ (0.32)
Increase of US$0.50 per Mcf in the price of NYMEX natural gas	$ 0.12
Decrease of US$0.50 per Mcf in the price of NYMEX natural gas	$ (0.12)
Change of 1,000 BOE/day in production	$ 0.03
Change of $0.01 in the US/CDN exchange rate	$ 0.02
Change of 1% in interest rate(2)	$ 0.02

(1) Calculated using 256.2 million shares outstanding at February 18, 2021.
(2) The interest rate sensitivity reflects the Term Facility, which will be fully drawn upon closing of the Bruin Acquisition. Enerplus is currently undrawn on its floating interest rate bank credit facility and all outstanding senior notes are based on fixed interest rates.

2021 GUIDANCE(1)

Summary of 2021 Annual Expectations	Target
Capital spending	$335 - $385 million
Average annual production	103,500 – 108,500 BOE/day
Average annual crude oil and natural gas liquids production	63,000 – 67,000 bbls/day

2021 Differential/Basis Outlook(2)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.25)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	US$(0.55)/Mcf

(1) Guidance is based on the continued operation of DAPL, the completion of the Bruin Acquisition at the beginning of March 2021 and a ten-month contribution from the Bruin assets.
(2) Excludes transportation costs

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. Netback is calculated as crude oil and natural gas sales less royalties, production taxes, operating expenses and transportation costs.

Calculation of Netback	**Year ended December 31,**		
($ millions)	**2020**	**2019**	**2018**
Crude oil and natural gas sales, net of royalties	$ 737.2	$ 1,254.8	$ 1,292.7
Less:			
Production taxes	(49.9)	(83.1)	(87.3)
Operating expenses	(263.6)	(290.8)	(238.3)
Transportation costs	(132.4)	(144.9)	(123.5)
Netback before hedging	$ 291.3	$ 736.0	$ 843.6
Cash gains/(losses) on derivative instruments	131.0	15.4	(35.8)
Netback after hedging	$ 422.3	$ 751.4	$ 807.8

"Adjusted funds flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Adjusted funds flow is calculated as cash flow from operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Year ended December 31,**		
($ millions)	**2020**	**2019**	**2018**
Cash flow from operating activities	$ 446.4	$ 694.2	$ 738.8
Asset retirement obligation expenditures	17.7	16.7	11.3
Changes in non-cash operating working capital	(105.9)	(1.9)	3.4
Adjusted funds flow	$ 358.2	$ 709.0	$ 753.5

"Free cash flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Free cash flow is calculated as adjusted funds flow minus capital spending.

Calculation of Free Cash Flow	**Year ended December 31,**		
($ millions)	**2020**	**2019**	**2018**
Adjusted funds flow	$ 358.2	$ 709.0	$ 753.5
Capital spending	(291.4)	(618.9)	(593.9)
Free cash flow	$ 66.8	$ 90.1	$ 159.6

"Adjusted net income" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the company by understanding the impact of certain non-cash items and other items that the Company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income is calculated as net income adjusted for unrealized derivative instrument gain/loss, asset impairments, unrealized foreign exchange gain/loss, the tax effect of these items, goodwill impairment, the impact of statutory changes to the Company's corporate tax rate and the valuation allowance on our deferred income tax assets. Adjusted net income in 2020 included adjustments related to asset impairments and the valuation allowance on deferred taxes. No asset impairments or valuation allowance on deferred taxes were recorded in 2019 or 2018.

Calculation of Adjusted Net Income	**Year ended December 31,**		
($ millions)	**2020**	**2019**	**2018**
Net income/(loss)	$ (923.4)	$ (259.7)	$ 378.3
Unrealized derivative instrument (gain)/loss	23.6	81.7	(124.3)
Asset impairment	994.8	—	—
Unrealized foreign exchange (gain)/loss	1.9	(34.1)	58.6
Tax effect on above items	(266.0)	(18.5)	32.2
Goodwill impairment	202.8	451.1	—
Income tax rate adjustment on deferred taxes	—	22.7	—
Valuation allowance on deferred taxes	(13.9)	—	—
Adjusted net income	$ 19.8	$ 243.2	$ 344.8

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and cash equivalents.

"Net debt to adjusted funds flow ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash divided by a trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depletion, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"Adjusted payout ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital spending, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Year ended December 31,**		
($ millions)	**2020**	**2019**	**2018**
Cash dividends	$ 26.7	$ 27.7	$ 29.3
Capital, office expenditures and line fill	295.7	629.8	600.4
Sub-total	$ 322.4	$ 657.5	$ 629.7
Adjusted funds flow	$ 358.2	$ 709.0	$ 753.5
Adjusted payout ratio (%)	90%	93%	84%

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**December 31, 2020**
Net income/(loss)	$ (923.4)
Add:	
Asset impairment	994.8
Goodwill impairment	202.8
Interest	28.4
Current and deferred tax expense/(recovery)	(260.8)
DD&A	293.2
Other non-cash charges(2)	38.1
Adjusted EBITDA	$ 373.1

(1) Adjusted EBITDA is calculated based on the trailing four quarters.
(2) Includes the change in fair value of commodity derivatives, equity swaps, non-cash SBC expense, and unrealized foreign exchange gains/losses.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "senior net debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "senior debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Internal Controls over Financial Reporting

We maintain internal controls over financial reporting that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. Management is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rule 13a – 15(f) and 15d – 15(f) under the U.S. Securities Exchange Act of 1934, as amended (the Exchange Act) and under National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 51-109). Management, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of Enerplus Corporation, have conducted an evaluation of our internal control over financial reporting based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013). Based on management's assessment as of December 31, 2020, management has concluded that our internal controls over financial reporting is effective.

The effectiveness of internal controls over financial reporting as of December 31, 2020 was audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm, which is included with the annual financial statements.

Due to its inherent limitations, internal controls over financial reporting is not intended to provide absolute assurance that a misstatement of our financial statements would be prevented or detected. Further, the evaluation of the effectiveness of internal control over financial reporting was made as of a specific date, and continued effectiveness in future periods is subject to the risks that controls may become inadequate.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal control over financial reporting in 2020 that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed in our interim and annual filings is reviewed, recognized and disclosed accurately and in the appropriate time period. Management, including the CEO and CFO, carried out an evaluation, as of December 31, 2020, of the effectiveness of the design and operation of disclosure controls and procedures of Enerplus, as defined in Rule 13a – 15(e) and 15d – 15(e) under the Exchange Act and NI 52-109. Based on that evaluation, the CEO and CFO have concluded that the design and operation of disclosure controls and procedures at Enerplus were effective to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act or Canadian securities legislation is recorded, processed, summarized and reported within the time periods specified in the rules and forms therein.

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

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: the continued uncertainty regarding timing and impact of COVID-19, expected 2021 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; anticipated production volumes subject to curtailment; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials and our commodity risk management program in 2021 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2021 and impact thereof on our production levels and land holdings; potential future asset impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements, including the entering into of Term Facility; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes; our future acquisitions and dispositions including the Bruin Acquisition and the completion, timing and anticipated benefits thereof; the impact of the Bruin Acquisition on Enerplus' operations, reserves, inventory and opportunities, financial condition and overall strategy; expecting timing thereof and use of proceeds therefrom; the amount of future cash dividends that we may pay to our shareholders, and our ESG initiatives, including GHG emissions and water reduction targets for 2021.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated, including the continued operation of DAPL; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; the satisfaction of the conditions to close the Bruin Acquisition and the Term Facility; the availability of third party services; the extent of our liabilities; and the availability of technology and process to achieve environmental targets. In addition, our 2021 guidance contained in this MD&A is based on the following: the completion of the Bruin Acquisition in the timeframe currently contemplated; and a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, a Bakken crude oil price differential of US$3.25/bbl below WTI and a USD/CDN exchange rate of 1.27. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors, reliance on industry partners and third party service providers; failure to complete the Bruin Acquisition in accordance with its terms or at all and failure to realize the anticipated benefits of the Bruin Acquisition; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF and Form 40-F as at December 31, 2020).

The purpose of our adjusted funds flow sensitivity is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Management's Report on Internal Control over Financial Reporting

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

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

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

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 18, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on Internal Control Over Financial Reporting

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of income/(loss) and comprehensive income/(loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements), and our report dated February 18, 2021 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP
Chartered Professional Accountants
Calgary, Canada
February 18, 2021

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 18, 2021. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 18, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Enerplus Corporation (the Company) as of December 31, 2020 and 2019, the related consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 18, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

Realizability of the deferred income tax asset associated with the Company's Canadian operation.

As discussed in Note 17 to the consolidated financial statements, as of December 31, 2020, the Company had recognized a deferred income tax asset of $607 million of which $211 million relates to the Company's Canadian operations. The Company estimated that there is a greater than 50 percent likelihood that the deferred income tax asset will be realized. The determination of the deferred income tax asset associated with the Canadian operation involves a number of estimates, including the future cash flows associated with the estimated proved and probable oil and gas reserves of the Canadian operation ("Canadian reserves"). The estimation of the Canadian reserves requires the expertise of independent reservoir engineering specialists, who take into consideration assumptions related to its forecasted production, forecasted operating, royalty and capital cost assumptions and forecasted oil and gas prices ("reserve assumptions"). The Company engages independent reservoir engineering specialists to estimate the Canadian reserves.

We identified the evaluation of the realizability of the Canadian operation's deferred income tax asset as a critical audit matter. Changes in reserve assumptions could have had a significant impact on the determination on the Company's ability to realize the Canadian operation's deferred income tax asset and the amount of a valuation allowance, if any. A high degree of auditor judgment was required in evaluating the Canadian reserve assumptions which were inputs to derive the recognized deferred income tax asset. Additionally, the evaluation of this estimate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the realizability of the Canadian deferred income tax assets, including controls over the estimation of the Canadian reserves and the related reserve assumptions. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the Canadian reserves. We evaluated the methodology used by independent reservoir engineering specialists to estimate the Canadian reserves for compliance with regulatory standards. We compared the 2020 actual production, operating, royalty and capital costs of the Canadian operations to those estimates used in the prior year's estimate of the proved reserves associated with the Canadian operations to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the Canadian reserves by comparing them to those published by other reserve engineering firms. We assessed the estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the Canadian reserves by comparing them to historical results. We involved Canadian income tax professionals with specialized skills and knowledge who assisted in evaluating the application of relevant tax laws and regulations used in the determination of the recognized deferred income tax asset.

Impact of estimated proved oil and gas reserves on the calculations of depletion expense and the ceiling test related to oil and gas properties.

As discussed in Note 2(d) to the consolidated financial statements, the Company depletes its oil and gas properties each quarter using the unit-of-production method on a country-by-country basis for Canada and the United States of America. Under such method, capitalized costs by country are depleted over the estimated proved oil and gas reserves for each of Canada and the United States of America ("country proved reserves"). For the year ended December 31, 2020, the Company recorded depletion, depreciation and accretion expense of $293 million. Additionally, as discussed in Note 2(d) to the consolidated financial statements, the Company is required to perform a quarterly ceiling test calculation on a country-by-country basis for Canada and the United States of America. For the year ended December 31, 2020, the Company recorded ceiling test impairments of $995 million. The Company limits the capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and the related deferred income tax effects, by country, to the estimated future net cash flows from country proved reserves discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved oil and gas properties. The estimation of country proved reserves, which are used in the calculations of depletion and the ceiling test, requires the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. The Company engages independent reservoir engineering specialists to estimate country proved reserves.

We identified the assessment of the impact of estimated country proved reserves on the calculations of depletion expense and the ceiling test related to oil and gas properties as a critical audit matter. Changes in reserve assumptions could have had a significant impact on the calculations of depletion expense and the ceiling tests. A high degree of auditor judgment was required in evaluating the country proved reserves, and related reserve assumptions, which were an input to the calculations of depletion expense and the ceiling test.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the calculations of depletion expense and the ceiling test, including controls over the estimation of the country proved reserves and the related reserve assumptions. We assessed the calculations of depletion expense and the ceiling test for compliance with regulatory standards. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the country proved reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate country proved reserves for compliance with regulatory standards. We compared the Company's 2020 actual production, operating, royalty and capital costs by country to those estimates used in the prior year estimate of country proved reserves to assess the Company's ability to accurately forecast. We assessed the estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the country proved reserves by comparing them to historical results.

Valuation of goodwill for the U.S. reporting unit

As discussed in note 5(b) to the consolidated financial statements the Company recorded goodwill impairment of $203 million related to the U.S. reporting unit. The Company assesses goodwill for impairment on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to the reporting unit's fair value. The estimated fair value of the U.S. reporting unit involves a number of estimates, including the future cash flows associated with the estimated proved oil and gas reserves of the U.S. reporting unit ("U.S. proved reserves") and the discount rate. The estimation of future cash flows associated with the U.S. proved reserves, requires the expertise of independent reservoir engineering specialists, who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate the U.S. proved reserves.

We identified the assessment of the valuation of goodwill for the U.S. reporting unit as a critical audit matter. Changes in reserve assumptions and the discount rate could have had a significant impact on the calculation of the fair value of the U.S. reporting unit. A high degree of auditor judgment was required in evaluating the Company's estimate of future cash flows associated with the U.S. proved reserves, and related reserve assumptions, and the discount rate, which were inputs to the calculation of the fair value of the U.S. reporting unit. Additionally, the evaluation of these estimates required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's determination of the fair value of the U.S. reporting unit, including controls related to the development of the discount rate and the estimation of future cash flows associated with the U.S. proved reserves and the related reserve assumptions. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the U.S. proved reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate the U.S. proved reserves for compliance with regulatory standards. We compared the Company's 2020 actual production, operating, royalty and capital costs of the U.S. reporting unit to those estimates used in the prior year's estimate of the U.S. proved reserves to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the U.S. proved reserves by comparing them to those published by other reserve engineering firms. We assessed the estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the U.S. proved reserves by comparing them to historical results. We involved a valuation professional with specialized skills and knowledge, who assisted in evaluating the Company's determination of the discount rate, by comparing the inputs to the discount rate to publicly available market data for comparable entities and assessing the resulting discount rate. The valuations specialist evaluated the Company's estimate of fair value of the U.S. reporting unit by comparing it to publicly available market data and valuation metrics for comparable entities or asset transactions.

/s/ KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 2017.

Calgary, Canada
February 18, 2021

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2020	December 31, 2019
Assets			
Current assets			
Cash and cash equivalents		$ 114,455	$ 151,649
Accounts receivable	3	106,209	176,119
Income tax receivable	13	167	27,770
Derivative financial assets	15	3,550	10,570
Other current assets		7,137	2,990
		231,518	369,098
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	4, 5	575,559	1,547,362
Other capital assets, net	4	19,524	20,244
Property, plant and equipment		595,083	1,567,606
Right-of-use assets	9	32,853	48,729
Goodwill	5, 17	—	194,015
Deferred income tax asset	13	607,001	372,502
Income tax receivable	13	—	13,852
Total Assets		$ 1,466,455	$ 2,565,802
Liabilities			
Current liabilities			
Accounts payable	6	$ 251,822	$ 291,540
Dividends payable		2,225	2,217
Current portion of long-term debt	7	103,836	105,998
Derivative financial liabilities	15	19,261	2,734
Current portion of lease liabilities	9	13,391	17,541
		390,535	420,030
Long-term debt	7	386,586	500,635
Asset retirement obligation	8	130,208	138,049
Lease liabilities	9	23,446	35,530
		540,240	674,214
Total Liabilities		930,775	1,094,244
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2020 – 223 million shares			
December 31, 2019 – 222 million shares	14	3,096,969	3,088,094
Paid-in capital		50,604	59,490
Accumulated deficit		(2,932,017)	(1,984,365)
Accumulated other comprehensive income		320,124	308,339
		535,680	1,471,558
Total Liabilities & Shareholders' Equity		$ 1,466,455	$ 2,565,802
Commitments and Contingencies	16		
Subsequent Events	19		

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Approved on behalf of the Board of Directors:

/s/ Hilary Foulkes
Director

/s/ Robert B. Hodgins
Director

Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

For the year ended December 31 (CDN$ thousands)	**Note**	**2020**	**2019**	**2018**
Revenues				
Crude oil and natural gas sales, net of royalties	10	$ 737,205	$ 1,254,806	$ 1,292,736
Commodity derivative instruments gain/(loss)	15	108,819	(66,071)	88,232
		846,024	1,188,735	1,380,968
Expenses				
Operating		263,575	290,766	238,261
Transportation		132,386	144,903	123,463
Production taxes		49,900	83,109	87,286
General and administrative	11	57,583	72,853	75,783
Depletion, depreciation and accretion		293,156	356,830	304,274
Asset impairment	5	994,776	—	—
Goodwill impairment	5	202,767	451,121	—
Interest		28,362	33,919	36,799
Foreign exchange (gain)/loss	12	1,338	(25,378)	39,521
Other expense/(income)		6,303	(7,529)	(5,909)
		2,030,146	1,400,594	899,478
Income/(Loss) Before Taxes		(1,184,122)	(211,859)	481,490
Current income tax expense/(recovery)	13	(14,525)	(33,414)	(27,093)
Deferred income tax expense/(recovery)	13	(246,230)	81,275	130,304
Net Income/(Loss)		$ (923,367)	$ (259,720)	$ 378,279
Other Comprehensive Income/(Loss)				
Unrealized gain/(loss) on foreign currency translation		9,583	(80,602)	125,817
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt, net of tax		2,202	—	—
Other Comprehensive Income/(Loss)		11,785	(80,602)	125,817
Total Comprehensive Income/(Loss)		$ (911,582)	$ (340,322)	$ 504,096
Net Income/(Loss) per Share				
Basic	14	$ (4.15)	$ (1.12)	$ 1.55
Diluted	14	$ (4.15)	$ (1.12)	$ 1.53

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2020**	**2019**	**2018**
Share Capital			
Balance, beginning of year	$ 3,088,094	$ 3,337,608	$ 3,386,946
Purchase of common shares under Normal Course Issuer Bid	(4,731)	(253,920)	(82,596)
Share-based compensation – treasury settled	13,824	4,406	23,389
Stock Option Plan – cash	(218)	—	9,138
Stock Option Plan – exercised	—	—	731
Balance, end of year	$ 3,096,969	$ 3,088,094	$ 3,337,608
Paid-in Capital			
Balance, beginning of year	$ 59,490	$ 46,524	$ 75,375
Share-based compensation – cash settled (tax withholding)	(7,232)	(4,952)	—
Share-based compensation – cash settled	—	—	(30,648)
Share-based compensation – equity settled	(13,824)	(4,406)	(23,389)
Share-based compensation – non-cash	12,170	22,324	25,917
Stock Option Plan – exercised	—	—	(731)
Balance, end of year	$ 50,604	$ 59,490	$ 46,524
Accumulated Deficit			
Balance, beginning of year	$ (1,984,365)	$ (1,772,084)	$ (2,124,676)
Purchase of common shares under Normal Course Issuer Bid	2,195	75,127	3,569
Net income/(loss)	(923,367)	(259,720)	378,279
Cancellation of predecessor shares	218	—	—
Dividends declared ($0.12 per share)	(26,698)	(27,688)	(29,256)
Balance, end of year	$ (2,932,017)	$ (1,984,365)	$ (1,772,084)
Accumulated Other Comprehensive Income			
Balance, beginning of year	$ 308,339	$ 388,941	$ 263,124
Unrealized gain/(loss) on foreign currency translation	9,583	(80,602)	125,817
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt, net of tax	2,202	—	—
Balance, end of year	$ 320,124	$ 308,339	$ 388,941
Total Shareholders' Equity	$ 535,680	$ 1,471,558	$ 2,000,989

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	**Note**	**2020**	**2019**	**2018**
Operating Activities				
Net income/(loss)		$ (923,367)	$ (259,720)	$ 378,279
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		293,156	356,830	304,274
Asset impairment	5	994,776	—	—
Goodwill impairment	5	202,767	451,121	—
Changes in fair value of derivative instruments	15	23,547	81,733	(124,266)
Deferred income tax expense/(recovery)	13	(246,230)	81,275	130,304
Foreign exchange (gain)/loss on debt and working capital	12	1,931	(34,085)	58,628
Share-based compensation and general and administrative	11, 14	12,726	23,044	25,917
Translation of U.S. dollar cash held in Canada (gain)/loss	12	(1,147)	8,794	(19,630)
Asset retirement obligation expenditures	8	(17,709)	(16,715)	(11,263)
Changes in non-cash operating working capital	18	105,915	1,963	(3,459)
Cash flow from operating activities		446,365	694,240	738,784
Financing Activities				
Repayment of senior notes	7	(114,010)	(59,429)	(29,044)
Proceeds from the issuance of shares (net of issue costs)	14	—	—	9,138
Purchase of common shares under Normal Course Issuer Bid	14	(2,536)	(178,793)	(79,027)
Share-based compensation – cash settled (tax withholding)	14	(7,232)	(4,952)	—
Dividends	14,18	(26,690)	(27,866)	(29,282)
Cash flow from/(used in) financing activities		(150,468)	(271,040)	(128,215)
Investing Activities				
Capital and office expenditures	18	(333,279)	(606,966)	(604,110)
Property and land acquisitions	4	(10,121)	(24,362)	(18,009)
Property divestments	4	6,145	9,539	(919)
Cash flow from/(used in) investing activities		(337,255)	(621,789)	(623,038)
Effect of exchange rate changes on cash and cash equivalents		4,164	(13,089)	29,248
Change in cash and cash equivalents		(37,194)	(211,678)	16,779
Cash and cash equivalents, beginning of year		151,649	363,327	346,548
Cash and cash equivalents, end of year		$ 114,455	$ 151,649	$ 363,327

The accompanying notes to the Consolidated Financial Statements are an integral part of these statements.

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada.

2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). Certain prior period amounts have been restated to conform with current period presentation.

i. Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' reporting currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include: crude oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment of property, plant and equipment, asset retirement obligations, income taxes, ability to realize deferred income tax assets, impairment assessments of goodwill and the fair value of derivative instruments. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous estimates and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

In early March 2020, the World Health Organization declared the coronavirus ("COVID-19") outbreak a pandemic. Responses to the spread of COVID-19 have resulted in a challenging economic climate, with more volatile commodity prices and foreign exchange rates, and a decline in long-term interest rates. Although global economies have begun to recover, markets remain volatile and the timing of a full economic recovery remains uncertain. It is difficult to reliably estimate the length or severity of these developments and their financial impact. The impacts of the economic downturn to Enerplus have been considered in management's estimates described above at December 31, 2020; however, estimates made during periods of extreme volatility are subject to a higher level of uncertainty and as a result, there may be further prospective material impacts in future periods.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled crude oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

iv. Business Combinations

The acquisition method of accounting is used to account for acquisitions that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

b) Revenue

Revenue from the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers, net of sales taxes. Enerplus recognizes revenue when it satisfies a performance obligation by transferring control of the product to a customer. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the contractual delivery points.

Enerplus evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, management considers if Enerplus retains control of the product being delivered to the end customer. As part of this assessment, management considers whether the Company retains the economic benefits associated with the good being delivered to the end customer. Management also considers whether the Company has the primary responsibility for the delivery of the product, the ability to establish prices or the inventory risk. If Enerplus acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

c) Transportation

Enerplus generally sells crude oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which the Company sells crude oil or natural gas at the wellhead and collects a price, net of the transportation incurred by the purchaser. In this case, sales are recorded at the price received from the purchaser, net of transportation costs.

Under the other arrangement, Enerplus sells crude oil or natural gas at a specific delivery point, pays transportation to a third party and receives proceeds from the purchaser with no transportation deduction. In this case, transportation costs are recorded as transportation expense on the Consolidated Statements of Income/(Loss). Due to these two distinct selling arrangements, Enerplus' computed realized prices, before the impact of derivative instruments, include revenues which are reported under two separate bases.

d) Crude oil and Natural Gas Properties

Enerplus uses the full cost method of accounting for its crude oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding crude oil and natural gas reserves are capitalized, including general and administrative costs attributable to these activities. These costs are recorded on a country-by-country cost centre basis as crude oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved crude oil and natural gas properties is depleted using the unit of production method using proved reserves, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis each quarter. Enerplus limits capitalized costs of proved and unproved crude oil and natural gas properties, net of accumulated depletion and the related deferred income tax effects, to the estimated future net cash flows from proved crude oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). This discount rate is not adjusted for current market trends, changes in the cost of capital and the potential impacts, if any, on the discount rate due to climate change factors. The ultimate period in which global energy markets can fully transition from carbon-based sources to alternative energy is highly uncertain. The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher crude oil and natural gas prices subsequently increase the ceiling.

Under full cost accounting rules, divestitures of crude oil and natural gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized.

e) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements, computer equipment and Company owned line-fill in third party pipelines. Line fill is recorded at lower of cost and net realizable value. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

f) Cash and Cash Equivalents

Cash and cash equivalents includes cash and highly liquid investments with maturities of less than 90 days.

g) Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that related to U.S. operations fluctuated due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to the reporting unit's fair value, with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. The estimated fair value of the reporting unit involves numerous estimates including the estimated cash flows from proved reserves (and in certain periods probable reserves) associated with the reporting unit and the appropriate discount rate to apply to the estimated cash flows. The discount rate is based on the estimated cost of capital.

h) Asset Retirement Obligations

Enerplus' crude oil and natural gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. Upon recognition, the liability is recorded at its estimated fair value. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability and related asset retirement cost can arise as a result of revisions in the estimated amount or timing of cash flows.

Depletion of asset retirement costs and increases in asset retirement obligations resulting from the passage of time are recorded to depreciation, depletion and accretion and charged against net income in the Consolidated Statements of Income/(Loss).

i) Leases

Enerplus determines if an arrangement is a lease at inception. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Operating and finance leases are included in right-of-use ("ROU") assets and the associated lease liability in the Consolidated Balance Sheet.

ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the obligation to make lease payments arising from the lease. Lease liabilities are recognized at lease commencement date based on the present value of remaining lease payments over the lease term. A corresponding ROU asset is recognized at the amount of the lease liability, adjusted for lease incentives received. Enerplus uses the implicit rate when readily available, or uses its incremental borrowing rate based on the information available at the commencement date in determining the present value of lease payments. Enerplus' lease terms may have options to extend or terminate the lease which are included in the calculation of lease liabilities when it is reasonably certain that it will exercise those options. Lease expense for operating leases is recognized on a straight-line basis over the lease term.

Lease agreements contain both lease and non-lease components which are accounted for separately. For certain equipment leases, a portfolio approach is applied to effectively account for the ROU assets and liabilities. Prior to January 1, 2019, the Company applied lease accounting in accordance with ASC 840. Results reported for 2020 and 2019 reflect the application of the new guidance while the 2018 comparative results were prepared and reported under previous lease guidance.

j) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment.

The expected future taxable income considered in the analysis of the valuation allowance is based on cash flows from the proven and probable reserves. The estimated cash flows from proven and probable reserves is subject to numerous estimates and judgments and involves the use of independent reserve evaluators. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest expense related to income tax are recognized in income tax expense.

k) Financial Instruments

i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. For financial instruments carried at fair value, and when disclosing the fair value of financial instruments on certain non-financial items, inputs used in determining the fair value are characterized according to the following fair value hierarchy:

- Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities.
- Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.
- Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

ii. Non-derivative financial instruments

The carrying amount of cash, accounts receivable, income tax receivable, accounts payable, dividends payable and bank credit facilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of the senior notes are considered a level 2 fair value measurement. The fair value of debt has been disclosed in Note 15.

The Company uses the current expected credit loss model for its accounts receivable, which requires the use of a lifetime expected loss provision. In making an assessment as to whether financial assets are credit-impaired, the Company considers: (i) historically realized bad debts; (ii) a counterparty's present financial condition and whether a counterparty has breached certain contracts; (iii) the probability that a counterparty will enter bankruptcy or other financial reorganization; (iv) changes in economic conditions that correlate to increased levels of default; and (v) the term to maturity of the specified receivable. The carrying amounts of receivables are reduced by the amount of the expected credit loss through an allowance account and losses are recognized within general and administrative expense in the Consolidated Statement of Income/(Loss). If the Company subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account.

Enerplus has designated certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. These non-derivative financial instruments will be accounted for under hedge accounting. To be accounted for as a hedge, the U.S. dollar denominated debt must be designated as an effective hedge, both at inception and on an ongoing basis. The required hedge documentation defines the relationship between the U.S. dollar denominated debt and the net investment in the U.S. subsidiary, as well as the Company's risk management objective and strategy for undertaking the hedging transaction. The Company formally assesses, both at inception and on an ongoing basis, whether the changes in fair value of the U.S. dollar denominated debt are highly effective in offsetting changes in fair value of the net investment in the U.S. subsidiary. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in Other Comprehensive Income/(Loss), net of tax, and are limited to the translation gain or loss on the net investment. Prior to January 1, 2020, the Company did not apply hedge accounting to the net investment in foreign operations and unrealized gains and losses were recognized in net income/loss at the end of the respective reporting period.

A reduction in the fair value of the net investment in the U.S. subsidiary or increase in the U.S. dollar denominated debt may result in a portion of the hedge becoming ineffective. If the hedging relationship ceases to be effective or is terminated, hedge accounting is not applied and subsequent gains or losses are recorded through net income/(loss).

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations.

Enerplus has not designated its financial derivative contracts as effective accounting hedges and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all remaining financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Realized gains and losses from commodity price risk management activities are recognized in income when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in income based on the changes in fair value of the contracts at the end of the respective reporting period.

Enerplus' crude oil, natural gas and natural gas liquids physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

l) Foreign Currency

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to the functional currency of the entity (Canadian dollars) using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency of the entity using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign operations

Assets and liabilities of Enerplus' U.S. operations, which has a U.S. dollar functional currency, are translated into Canadian dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment which is recorded in accumulated other comprehensive income.

m) Share-Based Compensation

Enerplus' share-based compensation plans include equity-settled Restricted Share Unit ("RSU") and Performance Share Unit ("PSU") awards made pursuant to its Share Award Incentive Plan ("SAIP"). The Company is authorized to issue up to 4.5% of outstanding common shares from treasury under the SAIP. Enerplus also has a cash-settled Deferred Share Unit ("DSU") Plan for Directors ("Director DSU Plan") and a cash-settled RSU Plan for Directors ("Director RSU Plan").

i. Long-term Incentive ("LTI") Plans

For RSU awards granted under the SAIP, employees receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

For PSU awards granted under the SAIP, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on the value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to a peer group of both Canadian and U.S. crude oil and natural gas producers over the vesting period.

Under Enerplus' Director DSU Plan and Director RSU Plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual equity retainer value. Directors may elect to receive all or a portion of their notional shares under either plan. Under the Director DSU Plan, units vest and are paid at a specified date following the director leaving the Board. Under the Director RSU Plan, units vest one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All Director DSU and RSU grants are settled in cash.

Enerplus recognizes non-cash share-based compensation expense over the vesting period of the equity-settled long-term incentive plans, net of realized forfeitures, based on the estimated grant date share price fair value of the respective awards. The grant date fair value is based on the Company's 20 day volume weighted average price on December 31 prior to the grant date. The fair value for the PSUs is adjusted for the outcome of the performance condition. Share-based compensation charges are recorded on the Consolidated Statements of Income/(Loss) with an offset to paid-in capital. Each period, management performs an estimate of the PSU plan multiplier. Any differences that arise between the actual multiplier on plan settlement and management's estimate is recorded to share-based compensation. On settlement of these plans, amounts previously recorded to paid-in capital are reclassified to share capital.

Enerplus recognizes a liability with respect to its cash-settled long-term incentive plans based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as share-based compensation, included in general and administrative expense.

ii. Stock options

Enerplus' Stock Option Plan was suspended in 2014 and is now closed. Remaining outstanding stock options expired in March 2020.

n) Net Income/(Loss) Per Share

Basic net income/(loss) per common share is computed by dividing net income/(loss) by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options and outstanding RSU's and PSU's would be used to repurchase common shares at the average market price.

o) Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recognized when it is probable that a liability has been incurred and the amount can be reasonably estimated. Contingencies are adjusted as additional information becomes available or circumstances change.

p) Accounting Changes and Recent Pronouncements Issued

Except for the changes below, the Company has consistently applied the accounting policies to all periods presented in these Consolidated Financial Statements, effective January 1, 2020:

- *ASU 2017-04, Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)* – The change was applied prospectively and was applied to the 2020 impairment of goodwill (Refer to Note 5).
- *ASC 815 – Derivatives and Hedging* – relating to the net investment in foreign operations for which the U.S. dollar is the functional currency. Effective January 1, 2020, foreign exchange gains and losses on Enerplus' U.S. denominated debt are recorded in other comprehensive income along with translation gains and losses on Enerplus' net investment in the U.S. Hedge accounting was applied prospectively thus the change did not impact comparative figures.
- *ASC 326 – Financial Instruments – Credit Losses* – modified retrospective method. The adoption of the standard had no impact on the financial statements.

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2020	December 31, 2019
Accrued revenue	$ 93,147	$ 142,048
Accounts receivable – trade	16,641	37,736
Allowance for doubtful accounts	(3,579)	(3,665)
Total accounts receivable, net of allowance for doubtful accounts	$ 106,209	$ 176,119

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

As at December 31, 2020 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties[1]	$ 15,227,076	$ (14,651,517)	$ 575,559
Other capital assets	127,527	(108,003)	19,524
Total PP&E	$ 15,354,603	$ (14,759,520)	$ 595,083

As at December 31, 2019 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties[1]	$ 15,088,724	$ (13,541,362)	$ 1,547,362
Other capital assets	125,265	(105,021)	20,244
Total PP&E	$ 15,213,989	$ (13,646,383)	$ 1,567,606

(1) All of the Company's unproved properties are included in the full cost pool.

Acquisitions:

For the years ended December 31, 2020 and 2019, Enerplus acquired property and land totaling $10.1 million and $24.4 million, respectively.

Divestments:

For the years ended December 31, 2020 and 2019, Enerplus disposed of properties for proceeds of $6.1 million and $9.6 million, respectively.

5) IMPAIRMENT

a) Impairment of PP&E

($ thousands)	2020	2019	2018
Crude oil and natural gas properties:			
Canada cost centre	$ 134,349	$ —	$ —
U.S. cost centre	860,427	—	—
Total impairment expense	$ 994,776	$ —	$ —

The PP&E impairments for the year ended December 31, 2020 were due to lower twelve-month average trailing crude oil and natural gas prices. There was no PP&E impairments recorded for the years ended December 31, 2019 and 2018. The primary factors that will affect future ceiling values include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, and production levels. The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2020, 2019 and 2018:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN
2020	$ 39.54	$ 45.56	$ 2.00	1.34
2019	55.85	66.73	2.58	1.33
2018	65.56	69.58	3.10	1.28

b) Impairment of Goodwill

Enerplus recorded goodwill impairment of $202.8 million related to its U.S. reporting unit for the year ended December 31, 2020 (December 31, 2019 - $451.1 million for the Canadian reporting unit). The impairment was a result of lower commodity prices, which resulted in a reduction in the fair value of the U.S. reporting unit. The U.S reporting unit for the goodwill impairment test was based on its reserve values at forecasted prices and costs at June 30, 2020. At December 31, 2020, there was no goodwill remaining on the Company's Condensed Consolidated Balance Sheet. There was no goodwill impairment for the year ended December 31, 2018.

The fair value of the U.S. reporting unit was estimated using proved reserves as at the measurement date base on forward price curves as determined by external reserve engineers and discounted using an estimated after-tax discount rate of 15%. The estimated fair value of the reporting units is considered a level 3 fair value under the fair value hierarchy.

6) ACCOUNTS PAYABLE

($ thousands)	December 31, 2020		December 31, 2019	
Accrued payables	$	107,254	$	105,928
Accounts payable – trade		144,568		185,612
Total accounts payable	$	251,822	$	291,540

7) DEBT

($ thousands)	December 31, 2020		December 31, 2019	
Current:				
Senior notes	$	103,836	$	105,998
Long-term:				
Bank credit facility	$	—	$	—
Senior notes		386,586		500,635
Total debt	$	490,422	$	606,633

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, US$600 million bank credit facility that matures on October 31, 2023. Drawn fees range between 125 and 315 basis points over bankers' acceptance and LIBOR rates. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility or repay the entire balance at the end of the term. At December 31, 2020, Enerplus was undrawn on the facility (December 31, 2019 – undrawn).

Senior Notes

During 2020, Enerplus made its fourth US$22 million principal repayment on its 2009 senior notes and its first US$59.6 million principal repayment on its 2012 senior notes. During 2019, Enerplus made its third US$22 million principal repayment on its 2009 senior notes and a $30 million bullet repayment on its 2012 senior notes. During 2018, Enerplus made its second US$22 million principal repayment on its 2009 senior notes.

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)	
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$	133,613
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000		25,450
May 15, 2012	May 15 and Nov 15	4 equal annual installments beginning May 15, 2021	4.40%	US$355,000	US$238,400		303,364
June 18, 2009	June 18	Final installment on June 18, 2021	7.97%	US$225,000	US$22,000		27,995
					Total carrying value	$	490,422

8) ASSET RETIREMENT OBLIGATION

($ thousands)	December 31, 2020	December 31, 2019
Balance, beginning of year	$ 138,049	$ 126,112
Change in estimates	1,331	23,362
Property acquisition and development activity	2,246	2,068
Divestments	(1,030)	(2,760)
Settlements	(17,709)	(16,715)
Accretion expense	7,321	5,982
Balance, end of year	$ 130,208	$ 138,049

Enerplus has estimated the present value of its asset retirement obligation to be $130.2 million at December 31, 2020 based on a total undiscounted, uninflated liability of $348.4 million (December 31, 2019 – $138.0 million and $344.7 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.35% and inflation rate of 0.9% (December 31, 2019 – 5.50% and 1.8%, respectively). The majority of Enerplus' asset retirement obligation expenditures are expected to be incurred between 2024 and 2046.

9) LEASES

The Company incurs lease payments related to office space, drilling rig commitments, vehicles and other equipment. Leases are entered into and exited in coordination with specific business requirements which include the assessment of the appropriate durations for the related leased assets. Short-term leases with a lease term of 12 months or less are not recorded on the Consolidated Balance Sheet. Such items are charged to operating expenses and general and administrative expenses in the Consolidated Statement of Income/(Loss), unless the costs are included in the carrying amount of another asset in accordance with other U.S. GAAP.

($ thousands)	December 31, 2020	December 31, 2019
Assets		
Operating right-of-use assets	$ 32,853	$ 48,729
Liabilities		
Current operating lease liabilities	$ 13,391	$ 17,541
Non-current operating lease liabilities	23,446	35,530
Total lease liabilities	$ 36,837	$ 53,071
Weighted average remaining lease term (years)		
Operating leases	3.9	4.3
Weighted average discount rate		
Operating leases	4.2%	4.1%

The components of lease expense for the year ended December 31, 2020 and 2019 are as follows:

($ thousands)	2020	2019
Operating lease cost	$ 16,585	$ 19,546
Variable lease cost	1,753	(63)
Short-term lease cost	9,512	15,332
Sublease income	(1,476)	(1,072)
Total	$ 26,374	$ 33,743

Maturities of lease liabilities, all of which are classified as operating leases at December 31, 2020, are as follows:

Maturity of Lease Liabilities ($ thousands)	**Operating Leases**
2021	$ 14,643
2022	8,285
2023	6,963
2024	6,202
2025	1,202
After 2025	2,696
Total lease payments	$ 39,991
Less imputed interest	(3,154)
Total discounted lease payments	$ 36,837
Current portion of lease liabilities	$ 13,391
Non-current portion of lease liabilities	$ 23,446

Supplemental information related to leases are as follows:

($ thousands)	**2020**	**2019**
Cash amounts paid to settle lease liabilities:		
Operating cash flow used for operating leases	$ 16,142	$ 18,637
Right-of-use assets obtained/(terminated) in exchange for lease obligations:		
Operating leases	$ (1,752)	$ 20,818

10) CRUDE OIL AND NATURAL GAS SALES

($ thousands)	**2020**	**2019**	**2018**
Crude oil and natural gas sales	$ 923,546	$ 1,572,955	$ 1,610,899
Royalties(1)	(186,341)	(318,149)	(318,163)
Crude oil and natural gas sales, net of royalties	$ 737,205	$ 1,254,806	$ 1,292,736

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).

Crude oil and natural gas revenue by country and by product for the years ended December 31, 2020 and 2019 are as follows:

2020 ($ thousands)	**Total revenue, net of royalties(1)**	**Crude oil(2)**	**Natural gas(2)**	**Natural gas liquids(2)**	**Other(3)**
Canada	$ 96,498	$ 78,798	$ 12,307	$ 3,452	$ 1,942
United States	640,707	508,294	119,030	13,233	149
Total	$ 737,205	$ 587,092	$ 131,337	$ 16,685	$ 2,091

2019 ($ thousands)	**Total revenue, net of royalties(1)**	**Crude oil(2)**	**Natural gas(2)**	**Natural gas liquids(2)**	**Other(3)**
Canada	$ 177,299	$ 145,814	$ 21,776	$ 7,158	$ 2,551
United States	1,077,507	847,182	215,963	14,355	7
Total	$ 1,254,806	$ 992,996	$ 237,739	$ 21,513	$ 2,558

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).
(2) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(3) Includes third party processing income.

Enerplus sells the majority of its production pursuant to variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, natural gas liquids or natural gas to the contract counterparty.

Crude oil, natural gas and natural gas liquids are sold under contracts of varying terms, including multi-year contracts. Revenues are typically collected in the month following production.

11) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2020	2019	2018
General and administrative expense[(1)]	$ 44,584	$ 49,532	$ 49,943
Share-based compensation expense	12,999	23,321	25,840
General and administrative expense	$ 57,583	$ 72,853	$ 75,783

(1) Includes non-cash lease expense/(inducement) of $(288) in 2020 and $(720) in 2019.

12) FOREIGN EXCHANGE

($ thousands)	2020	2019	2018
Realized:			
Foreign exchange (gain)/loss	$ 554	$ (87)	$ 523
Translation of U.S. dollar cash held in Canada (gain)/loss	(1,147)	8,794	(19,630)
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	1,931	(34,085)	58,628
Foreign exchange (gain)/loss	$ 1,338	$ (25,378)	$ 39,521

13) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2020	2019	2018
Current tax			
Canada	$ —	$ (13,910)	$ (400)
United States	(14,525)	(19,504)	(26,693)
Current tax expense/(recovery)	(14,525)	(33,414)	(27,093)
Deferred tax			
Canada	$ (24,584)	$ 11,023	$ 3,915
United States	(221,646)	70,252	126,389
Deferred tax expense/(recovery)	(246,230)	81,275	130,304
Income tax expense/(recovery)	$ (260,755)	$ 47,861	$ 103,211

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

($ thousands)	2020	2019	2018
Income/(loss) before taxes			
Canada	$ (13,507)	$ (437,571)	$ 104,204
United States	(1,170,615)	225,712	377,286
Total income/(loss) before taxes	(1,184,122)	(211,859)	481,490
Canadian statutory rate	24.00%	26.50%	27.00%
Expected income tax expense/(recovery)	$ (284,189)	$ (56,143)	$ 130,002
Impact on taxes resulting from:			
Foreign and statutory rate differences	$ (37,451)	$ 27,446	$ (23,859)
Share-based compensation	2,073	(5,398)	(18,102)
Capital gains and losses	17,261	3,994	7,254
Change in valuation allowance	(31,195)	(22,038)	6,292
Amounts in respect of prior periods	8,905	(19,451)	—
Non-deductible goodwill impairment and other expenses	63,841	119,451	1,624
Income tax expense/(recovery)	$ (260,755)	$ 47,861	$ 103,211

During the year, the Alberta corporate income tax rate change resulted in a decrease to the Canadian statutory rate by 2.5% for 2020.

The deferred income tax asset consists of the following:

As at December 31 ($ thousands)	2020	2019
Deferred income tax assets		
Property, plant and equipment	$ 177,799	$ 59,896
Tax loss carry-forwards and other credits	385,934	383,600
Capital loss carryforwards and other capital items	141,880	154,532
Asset retirement obligation	31,793	33,569
Derivative financial instruments	3,723	—
Other assets	8,486	12,219
Deferred income tax assets before valuation allowance	749,615	643,816
Valuation allowance	(142,614)	(169,129)
Deferred income tax assets, net	607,001	474,687
Deferred income tax liabilities		
Property, plant and equipment	$ —	$ (100,328)
Derivative financial instruments	—	(1,857)
Total deferred income tax liabilities	—	(102,185)
Total deferred income tax asset	$ 607,001	$ 372,502

In 2020, $14.5 million was reclassified from deferred income tax asset to income tax receivable for the recognition of the final portion of the AMT refund. As of December 31, 2020, all outstanding AMT refunds have been received.

Loss carryforwards available for tax reporting purposes:

As at December 31 ($ thousands)	2020	Expiration Date
Canada		
Capital losses	$ 1,053,000	Indefinite
Non-capital losses	284,000	2031-2039
United States		
Net operating losses – prior to 2018	$ 875,000	2030-2040
Net operating losses – 2018 and thereafter	316,000	Indefinite

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

($ thousands)	2020	2019	2018
Balance, beginning of year	$ —	$ 13,300	$ 13,300
Increase - tax positions in prior periods	21,030	—	—
Settlements	—	(13,300)	—
Balance, end of year	$ 21,030	$ —	$ 13,300

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2020 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

Jurisdiction	Taxation Years
Canada – Federal	2015-2020
United States – Federal	2017-2020

Enerplus and its subsidiaries file income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

14) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized: unlimited number of common shares **Issued:** (thousands)	2020 Shares	2020 Amount	2019 Shares	2019 Amount	2018 Shares	2018 Amount
Balance, beginning of year	221,744	$ 3,088,094	239,411	$ 3,337,608	242,129	$ 3,386,946
Issued for cash:						
Purchase of common shares under Normal Course Issuer Bid	(340)	(4,731)	(18,231)	(253,920)	(5,925)	(82,596)
Stock Option Plan	—	—	—	—	668	9,138
Non-cash:						
Share-based compensation – settled(1)	1,160	13,824	564	4,406	2,539	23,389
Stock Option Plan – exercised	—	—	—	—	—	731
Cancellation of predecessor shares	(16)	(218)	—	—	—	—
Balance, end of year	222,548	$ 3,096,969	221,744	$ 3,088,094	239,411	$ 3,337,608

(1) The amount of shares issued on LTI settlement is net of employee withholding taxes in 2020 and 2019.

The Company is authorized to issue an unlimited number of common shares without par value.

For the year ended December 31, 2020, Enerplus declared dividends of $0.12 per weighted average common share totaling $26.7 million (December 31, 2019 - $0.12 per share and $27.7 million, December 31, 2018 – $0.12 per share and $29.3 million).

Enerplus' Normal Course Issuer Bid ("NCIB") expired on March 25, 2020. All repurchases were made in accordance with the NCIB at prevailing market prices plus brokerage fees, with consideration allocated to share capital up to the average carrying amount of the shares, and any excess allocated to accumulated deficit.

For the year ended December 31, 2020, the Company repurchased 340,434 common shares under the NCIB at an average price of $7.44 per share, for total consideration of $2.5 million. Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit.

For the year ended December 31, 2019, the Company repurchased 18,231,401 common shares under the NCIB at an average price of $9.80 per share, for total consideration of $178.8 million. Of the amount paid, $253.9 million was charged to share capital and $75.1 million was credited to accumulated deficit.

b) Share-based Compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Consolidated Statements of Income/(Loss):

($ thousands)	2020	2019	2018
Cash:			
Long-term incentive plans expense	$ (1,411)	$ 689	$ 133
Non-Cash:			
Long-term incentive plans expense	13,014	22,324	25,917
Equity swap (gain)/loss	1,396	308	(210)
Share-based compensation expense	$ 12,999	$ 23,321	$ 25,840

i) LTI Plans

The following table summarizes the PSU, RSU and DSU activity for the year ended December 31, 2020:

For the year ended December 31, 2020	**Cash-settled LTI Plans**	**Equity-settled LTI Plans**		**Total**
(thousands of units)	**DSU**	**PSU(1)**	**RSU**	
Balance, beginning of year	422	2,139	1,531	4,092
Granted	133	1,203	1,142	2,478
Vested	—	(652)	(741)	(1,393)
Forfeited	—	(138)	(107)	(245)
Balance, end of year	555	2,552	1,825	4,932

(1) Based on underlying awards before any effect of the performance multiplier.

Cash-settled LTI Plans

For the year ended December 31, 2020, the Company recorded a cash share-based compensation recovery of $1.4 million (2019 – expense of $0.7 million; 2018 – expense of $0.1 million).

As of December 31, 2020, a liability of $2.2 million (December 31, 2019 – $3.9 million) with respect to the Director DSU Plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

The following table summarizes the cumulative share-based compensation expense recognized to-date which is recorded to Paid-in Capital on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At December 31, 2020 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 18,564	$ 13,474	$ 32,038
Unrecognized share-based compensation expense	7,444	5,497	12,941
Fair value	$ 26,008	$ 18,971	$ 44,979
Weighted-average remaining contractual term (years)	1.8	1.4	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the year ended December 31, 2020 cash withholding taxes of $7.2 million were paid (2019 - $5.0 million, 2018 – nil).

ii) Stock Option Plan

At December 31, 2020, all stock options are fully vested and all non-cash share-based compensation expense has been fully recognized. All remaining outstanding stock options expired in March 2020.

The following table summarizes the stock option plan activity for the year ended December 31, 2020:

Year ended December 31, 2020	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	2,107	$ 14.24
Exercised	—	—
Forfeited	(8)	14.85
Expired	(2,099)	14.24
Options outstanding and exercisable, end of year	—	$ —

c) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

(thousands, except per share amounts)	2020	2019	2018
Net income/(loss)	$ (923,367)	$ (259,720)	$ 378,279
Weighted average shares outstanding – Basic	222,503	231,334	244,076
Dilutive impact of share-based compensation(1)	—	—	3,185
Weighted average shares outstanding – Diluted	222,503	231,334	247,261
Net income/(loss) per share			
Basic	$ (4.15)	$ (1.12)	$ 1.55
Diluted	$ (4.15)	$ (1.12)	$ 1.53

(1) For the years ended December 31, 2020 and 2019, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2020, the senior notes had a carrying value of $490.4 million and a fair value of $494.1 million (December 31, 2019 – $606.6 million and $613.8 million, respectively). The fair value of the senior notes is estimated based on the amount that Enerplus would have to pay a third party to assume the debt, including the credit spread for the difference between the issue rate and the period end market rate. The period end market rate is estimated by comparing the debt to new issuances (secured or unsecured) and secondary trades of similar size and credit statistics for both public and private debt.

There were no transfers between fair value hierarchy levels during the year.

b) Derivative Financial Instruments

The derivative financial assets and liabilities on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following tables summarize the change in fair value for the respective years:

Gain/(Loss) ($ thousands)	**2020**	**2019**	**2018**	**Income Statement Presentation**
Equity Swaps	$ (1,396)	$ (308)	$ 210	G&A expense
Commodity Derivative Instruments:				
Oil	(25,701)	(70,481)	114,822	Commodity derivative instruments
Gas	3,550	(10,944)	9,234	
Total Unrealized Gain/(Loss)	$ (23,547)	$ (81,733)	$ 124,266	

The following table summarizes the effect of Enerplus' commodity derivative instruments on the Consolidated Statements of Income/(Loss):

($ thousands)	**2020**	**2019**	**2018**
Change in fair value gain/(loss)	$ (22,151)	$ (81,425)	$ 124,056
Net realized cash gain/(loss)	130,970	15,354	(35,824)
Commodity derivative instruments gain/(loss)	$ 108,819	$ (66,071)	$ 88,232

The following table summarizes the fair values at the respective year ends:

	December 31, 2020		**December 31, 2019**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
($ thousands)	**Current**	**Current**	**Current**	**Current**
Equity Swaps	$ —	$ 3,613	$ —	$ 2,217
Commodity Derivative Instruments:				
Oil	—	15,648	10,570	517
Gas	3,550	—	—	—
Total	$ 3,550	$ 19,261	$ 10,570	$ 2,734

The fair value of commodity derivative instruments and the equity swaps is estimated based on commodity and option pricing models that incorporates various factors including forecasted commodity prices, volatility and the credit risk of the entities party to the contract. Changes in commodity prices over the term of the contracts can result in material differences between the estimated fair value at a point in time and the actual settlement amounts of the contracts.

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates, equity prices, credit risk and liquidity risk.

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize Enerplus' price risk management positions at February 18, 2021:

Crude Oil Instruments:

Instrument Type(1)(2)	bbls/day	US$/bbl
Jan 1, 2021 – Mar 31, 2021		
WTI Swap	5,000	45.55
WTI Purchased Put	15,000	40.53
WTI Sold Put	15,000	32.00
WTI Sold Call	15,000	50.29
Apr 1, 2021 – Jun 30, 2021		
WTI Purchased Put	20,000	40.90
WTI Sold Put	20,000	32.00
WTI Sold Call	20,000	50.72
UHC Differential Swap	1,500	(1.80)
Jul 1, 2021 – Dec 31, 2021		
WTI Purchased Put	23,000	46.39
WTI Sold Put	23,000	36.39
WTI Sold Call	23,000	56.70
UHC Differential Swap	1,500	(1.80)
Jan 1, 2022 – Dec 31, 2022		
WTI Purchased Put	17,000	50.00
WTI Sold Put	17,000	40.00
WTI Sold Call	17,000	57.91

(1) Transactions with a common term have been aggregated and presented as the weighted average price/bbl before premiums.
(2) The total average deferred premium spent on our outstanding hedges is US$0.80/bbl from January 1, 2021 – December 31, 2021 and US$1.50/bbl from January 1, 2022 – December 31, 2022.

Natural Gas Instruments:

Instrument Type	MMcf/day	US$/Mcf
Mar 1, 2021 - Mar 31, 2021		
NYMEX Swap	60,000	3.16
Apr 1, 2021 – Oct 31, 2021		
NYMEX Swap	60,000	2.90
NYMEX Purchased Put	40,000	2.75
NYMEX Sold Put	40,000	2.15
NYMEX Sold Call	40,000	3.25

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a significant portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At December 31, 2020, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At December 31, 2020, all of Enerplus' debt was based on fixed interest rates, and Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing in 2021 that effectively fix the future settlement cost on a portion of its cash settled LTI plans.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2020, approximately 82% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2020 was $3.6 million (December 31, 2019 – $3.7 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash and cash equivalents) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, share repurchases, access to capital markets, as well as acquisition and divestment activity.

At December 31, 2020, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

16) COMMITMENTS AND CONTINGENCIES

a) Commitments

Enerplus has the following minimum annual commitments, excluding operating leases which are recorded in the lease liability (see Note 9):

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2021	2022	2023	2024	2025	Thereafter
Senior notes[1]	$ 490,422	$ 103,836	$ 128,014	$ 102,564	$ 102,564	$ 26,722	$ 26,722
Transportation commitments	289,993	44,539	30,393	29,358	29,088	29,101	127,514
Processing commitments	9,489	1,519	1,519	1,519	1,519	1,519	1,894
Total commitments[2][3]	$ 789,904	$ 149,894	$ 159,926	$ 133,441	$ 133,172	$ 57,343	$ 156,131

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2020 foreign exchange rate of 1.2725.

b) Contingencies

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

17) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2020 ($ thousands)	Canada	U.S.	Total
Crude oil and natural gas sales, net of royalties	$ 96,498	$ 640,707	$ 737,205
Depletion, depreciation and accretion	46,784	246,372	293,156
Property, plant and equipment	112,195	482,888	595,083
Deferred income tax asset	210,615	396,386	607,001

As at and for the year ended December 31, 2019 ($ thousands)	Canada	U.S.	Total
Crude oil and natural gas sales, net of royalties	$ 177,299	$ 1,077,507	$ 1,254,806
Depletion, depreciation and accretion	59,936	296,894	356,830
Property, plant and equipment	259,514	1,308,092	1,567,606
Deferred income tax asset	185,880	186,622	372,502
Goodwill	—	194,015	194,015
Long term income tax receivable	—	13,852	13,852

As at and for the year ended December 31, 2018 ($ thousands)	Canada	U.S.	Total
Crude oil and natural gas sales, net of royalties	$ 198,263	$ 1,094,473	$ 1,292,736
Depletion, depreciation and accretion	58,333	245,941	304,274
Property, plant and equipment	262,159	1,044,912	1,307,071
Deferred income tax asset	196,903	268,221	465,124
Goodwill	451,121	203,678	654,799
Long term income tax receivable	—	27,195	27,195

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2020	December 31, 2019	December 31, 2018
Accounts receivable	$ 112,041	$ 8,493	$ (45,385)
Other assets	(5,611)	4,475	(3,026)
Accounts payable	(515)	(11,005)	44,952
	$ 105,915	$ 1,963	$ (3,459)

b) Changes in Other Non-Cash Working Capital

($ thousands)	December 31, 2020	December 31, 2019	December 31, 2018
Non-cash financing activities(1)	$ 8	$ (178)	$ (26)
Non-cash investing activities(2)	$ (37,509)	$ 17,682	$ (3,753)

(1) Relates to changes in dividends payable and included in dividends on the Consolidated Statements of Cash Flows.
(2) Relates to changes in accounts payable for capital and office expenditures and included in capital and office expenditures on the Consolidated Statements of Cash Flows.

c) Other

($ thousands)	December 31, 2020	December 31, 2019	December 31, 2018
Income taxes paid/(received)	$ (58,361)	$ (71,890)	$ (481)
Interest paid	$ 28,758	$ 33,991	$ 36,161

19) SUBSEQUENT EVENTS

On January 25, 2021, the Company entered into a purchase agreement to acquire the equity interest of Bruin E&P HoldCo, LLC for total cash consideration of US$465 million, subject to customary purchase price adjustments (the "Bruin Acquisition"). On the same date, we entered into a binding commitment letter for a new three-year senior unsecured US$400 million term loan to be fully drawn down on the closing date of the Bruin Acquisition to pay for a portion of the purchase price. We intend to fund the remaining portion of the purchase price with net proceeds from a $132.3 million bought deal equity financing, issuing 33,062,500 common shares at a price of $4.00 per common share, which we completed on February 3, 2021. The Bruin Acquisition is expected to close in early March 2021.

FIVE YEAR SUMMARY

	2020	2019	2018	2017	2016
Daily Production Volumes[1]					
Crude oil (bbls/day)	45,421	49,704	45,424	36,935	38,353
Natural gas liquids (bbls/day)	5,633	4,929	4,486	3,858	4,903
Natural gas (Mcf/day)	237,857	278,451	259,837	263,506	299,214
BOE per day	90,697	101,042	93,216	84,711	93,125
Drilling Activity (net wells)	42	56	61	46	25
Average Benchmark Pricing					
WTI crude oil (US$ per bbl)	$ 39.40	$ 57.03	$ 64.77	$ 50.95	$ 43.32
Brent (ICE) crude oil (US$/bbl)	43.21	64.18	71.53	54.83	45.04
NYMEX natural gas - last day (US$ per Mcf)	2.08	2.63	3.09	3.11	2.46
USD/CDN exchange rate (average)	1.34	1.33	1.30	1.30	1.32
Realized Pricing[2]					
Crude oil (per bbl)	$ 44.35	$ 68.98	$ 74.59	$ 58.69	$ 44.84
Natural gas liquids(per bbl)	10.29	15.19	28.31	30.01	15.29
Natural gas (per Mcf)	1.87	2.87	3.42	3.21	2.06
Financial ($ thousands, except per share amounts)					
Oil and natural gas sales[2]	$ 923,547	$ 1,572,955	$ 1,610,899	$ 1,141,770	$ 882,126
Cash flow from operating activities	446,365	694,240	738,784	476,125	312,290
Adjusted funds flow[3]	358,160	708,992	753,506	524,064	305,605
Cash and stock dividends to Shareholders	26,698	27,688	29,256	29,033	35,439
Per share	0.12	0.12	0.12	0.12	0.16
Capital spending	291,468	618,910	593,876	458,015	209,135
Property and land acquisitions	10,121	24,406	25,840	13,276	126,126
Property divestitures	6,145	9,583	6,912	56,196	670,364
Total net capital expenditures[4]	298,230	644,610	619,285	417,755	(333,627)
Total assets	1,466,455	2,565,802	3,118,300	2,645,832	2,638,850
Total debt net of cash and restricted cash	375,967	454,984	333,523	325,831	375,520
Adjusted payout ratio[3][5]	90%	93%	84%	93%	80%
Net debt to adjusted funds flow ratio	1.0x	0.6x	0.4x	0.6x	1.2x
Royalties and production taxes rate	25.6%	25.5%	25.2%	24.1%	22.3%
Oil and Gas Economics per BOE					
Oil & natural gas sales[2]	$ 27.82	$ 42.65	$ 47.35	$ 36.93	$ 25.88
Transportation costs	(3.99)	(3.93)	(3.63)	(3.60)	(3.14)
Royalties and production taxes	(7.12)	(10.88)	(11.92)	(8.91)	(5.77)
Cash gains/(losses) on commodity derivative instruments	3.95	0.42	(1.05)	0.28	2.36
Average realized price, net	20.66	28.26	30.75	24.70	19.33
Cash operating expenses	(7.94)	(7.88)	(7.00)	(6.39)	(7.31)
Netback, after hedging[3]	12.72	20.38	23.75	18.31	12.02
Cash general and administrative expenses	(1.31)	(1.34)	(1.48)	(1.66)	(1.84)
Cash interest, foreign exchange and other expenses	(1.06)	(0.72)	(0.92)	(1.24)	(1.28)
Current income tax recovery/(expense)	0.44	0.91	0.80	1.55	0.07
Adjusted funds flow[3]	$ 10.79	$ 19.23	$ 22.15	$ 16.96	$ 8.97
Trading Information					
Canadian trading summary[6]					
High	$ 9.55	$ 12.55	$ 18.04	$ 13.35	$ 13.55
Low	$ 1.62	$ 7.32	$ 9.65	$ 8.97	$ 2.68
Close	$ 3.98	$ 9.25	$ 10.62	$ 12.31	$ 12.74
Volume (in 000's)	747,069	508,744	533,666	520,460	688,243
U.S. trading summary[7]					
High	$ 7.35	$ 9.74	$ 13.87	$ 10.21	$ 10.33
Low	$ 1.15	$ 5.50	$ 6.84	$ 6.52	$ 1.84
Close	$ 3.13	$ 7.13	$ 7.76	$ 9.79	$ 9.48
Volume (in 000's)	394,674	250,782	245,759	261,215	347,941
Weighted average number of shares outstanding (basic)[8]	222,503	231,334	244,076	241,929	226,530
Number of shares outstanding at December 31[8]	222,548	221,744	239,411	242,129	240,483

(1) Production is on a company interest basis.
(2) Before transportation, royalties and the effects of commodity derivative instruments.
(3) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the MD&A.
(4) Includes office capital and line fill.
(5) Calculated as the sum of cash dividends to shareholders, office capital, line fill and capital spending, divided by adjusted funds flow.
(6) Canadian composite trading data including TSX thereafter.
(7) U.S. composite trading data including NYSE thereafter.
(8) All shares are in thousands.

($ thousands)	2020	2019	2018	2017	2016
Reserves [1]					
Proved Reserves					
Crude oil (Mbbls)	129,769	140,703	137,348	122,543	119,419
NGLs (Mbbls)	14,900	14,327	13,783	13,000	11,825
Conventional natural gas (MMcf)	17,353	24,242	31,007	55,992	95,769
Shale gas (MMcf)	929,546	933,737	849,063	803,018	726,614
MBOE	302,485	314,693	297,809	278,711	268,308
Probable Reserves					
Crude oil (Mbbls)	71,633	77,498	70,870	68,479	56,798
NGLs (Mbbls)	8,602	8,396	7,277	7,752	6,273
Conventional natural gas (MMcf)	5,811	7,395	10,129	21,289	30,521
Shale gas (MMcf)	244,388	233,613	300,449	233,742	276,169
MBOE	121,934	126,061	129,909	118,737	114,186
Proved Plus Probable Reserves					
Crude oil (Mbbls)	201,402	218,201	208,215	191,022	176,216
NGLs (Mbbls)	23,501	22,723	21,060	20,752	18,098
Conventional natural gas (MMcf)	23,164	31,637	41,137	77,281	126,290
Shale gas (MMcf)	1,173,934	1,167,349	1,149,511	1,036,760	1,002,783
MBOE	424,419	440,755	427,718	397,448	382,493
Reserves Life Index[2]					
Proved (years)	9.5	8.9	8.4	9.2	9.0
Proved plus probable (years)	12.7	12.0	11.3	12.6	12.3
Finding & Development Costs and Finding, Development & Acquisition Costs[3]					
Proved Reserves					
Finding & Development Costs					
Capital expenditures	$ 291.4	$ 618.9	$ 593.8	$ 458.0	$ 209.1
Net change in future development costs	$ (150.5)	$ 2.4	$ 309.3	$ 114.0	$ (124.4)
Gross reserves additions (MMBOE)	20.8	54.6	54.1	50.5	47.2
F&D costs ($/BOE)	**$ 6.78**	**$ 11.37**	**$ 16.69**	**$ 11.32**	**$ 1.79**
Finding, Development & Acquisition Costs					
Capital expenditures and net acquisitions	$ 295.4	$ 633.7	$ 612.7	$ 415.1	$ (335.1)
Net change in future development costs	$ (150.5)	$ (0.5)	$ 308.3	$ 96.7	$ (202.1)
Gross reserves additions (MMBOE)	20.8	53.6	52.9	41.0	24.7
FD&A costs ($/BOE)	**$ 6.97**	**$ 11.82**	**$ 17.42**	**$ 12.48**	**$ (21.74)**
Proved Plus Probable Reserves					
Finding & Development Costs					
Capital expenditures	$ 291.4	$ 618.9	$ 593.8	$ 458.0	$ 209.1
Net change in future development costs	$ (183.2)	$ 47.0	$ 309.1	$ 102.8	$ (4.0)
Gross reserves additions (MMBOE)	16.7	51.0	65.7	58.0	42.6
F&D costs ($/BOE)	**$ 6.50**	**$ 13.05**	**$ 13.74**	**$ 9.68**	**$ 4.82**
Finding, Development & Acquisition Costs					
Capital expenditures and net acquisitions	$ 295.4	$ 633.7	$ 612.7	$ 415.1	$ (335.1)
Net change in future development costs	$ (183.2)	$ 44.0	$ 308.1	$ 85.1	$ (94.5)
Gross reserves additions (MMBOE)	16.7	49.7	64.1	45.6	10.3
FD&A costs ($/BOE)	**$ 6.74**	**$ 13.63**	**$ 14.37**	**$ 10.98**	**$ (41.60)**

(1) Reserves are based on gross reserves volumes.
(2) The Reserves Life Indices (RLI) are based upon year-end proved and proved plus probable reserves divided by the following year's proved and proved plus probable working interest production volumes as forecast in the independent reserves engineering reports.
(3) Includes future development capital.

ABBREVIATIONS

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

Bcf billion cubic feet

BOE[(1)] barrels of oil equivalent

Brent crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

DAPL Dakota Access pipeline

LTI long-term incentive

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

MMcf million cubic feet

MMBOE million barrels of oil equivalent

MSW Mixed Sweet Blend is the benchmark for conventionally produced light sweet crude for Western Canada

NCIB Normal Course Issuer Bid

NGL natural gas liquid

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserves reporting in Canada)

NYMEX New York Mercantile Exchange, the benchmark for North American natural gas pricing

2P Reserves proved plus probable reserves

RLI reserves life index

SBC share based compensation

SEC United States Securities and Exchange Commission

Transco Leidy Price benchmark for Marcellus natural gas delivered into the Transco pipeline system between Hunterdon County, New Jersey and connections east of the Leidy storage facility in Clinton and Potter Counties in Pennsylvania

Transco Z6 Non-New York Price benchmark for Marcellus natural gas delivered into the Transco pipeline system from the start of zone 6 at the Virginia-Maryland border to the Linden, New Jersey, compressor station and on the 24-inch pipeline to the Wharton, Pennsylvania, station

U.S. GAAP accounting principles generally accepted in the United States of America

WCS Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes

WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves*, *Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*" in the Annual Information Form.

DEFINITIONS

Contingent Resources Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are economically recoverable based on the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd., and Sproule Associates Limited as of January 1, 2020.

The economic contingent resources estimates are presented as the "best estimate" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the "best estimate", and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the "best estimate".

BOE Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Future Development Costs (FDC) Future Development Costs is defined as those costs which reflect the independent evaluator's best estimate of what it will cost to bring the proved and probable non-producing and undeveloped reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, additions to non-producing and undeveloped reserves and capital cost estimate revisions.

F&D Costs Finding and development costs. It is a measure of the effectiveness of a company's capital program. F&D costs presented are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year. F&D costs are presented in Canadian dollars per working interest BOE unless otherwise specified.

FD&A Costs Finding, development and acquisition costs. It is a measure of a company's ability to add reserves in a cost-effective manner. FD&A costs presented are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year. FD&A costs are presented in Canadian dollars per working interest BOE unless otherwise specified.

NGLs Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

Production, Company Interest Our working interest (operated and non-operated) share of production before the deduction of royalties, but inclusive of any royalty interest production owned by Enerplus. Therefore, the "company interest" production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" production should not be construed as an alternative to "gross" or "net" production calculated in accordance with NI 51-101.

Production, Gross Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.

Reserves Life Index, Proved Calculated as proved reserves at year-end divided by the following year's estimated proved working interest production volumes as determined by the independent reserves engineering report.

Reserves Life Index, Proved plus Probable Calculated as proved plus probable reserves at year-end divided by the following year's estimated proved plus probable working interest production volumes as determined by the independent reserves engineering report.

Reserves, Gross Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.

Reserves, Net Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.

Reserves, Probable Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Reserves, Proved Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Reserves, Developed Non-Producing Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Reserves, Developed Producing Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Reserves, Undeveloped Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.

BOARD OF DIRECTORS

Hilary A. Foulkes(1)(2)

Corporate Director
Calgary, Alberta

Judith D. Buie(3)(5)(7)

Corporate Director
Houston, Texas

Karen E. Clarke-Whistler(5)(9)(11)

Corporate Director
Toronto, Ontario

Ian C. Dundas

President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Robert B. Hodgins(3)(6)(9)

Corporate Director
Calgary, Alberta

Susan M. MacKenzie(4)(10)(11)

Corporate Director
Calgary, Alberta

Elliott Pew

Corporate Director
Boerne, Texas

Jeffrey W. Sheets(5)(7)(12)

Corporate Director
Houston, Texas

Sheldon B. Steeves(3)(8)(11)

Corporate Director
Calgary, Alberta

(1) Chair of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chair of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chair of the Safety & Social Responsibility Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas

President &
Chief Executive Officer

Wade D. Hutchings

Senior Vice President &
Chief Operating Officer

Jodine J. Jenson Labrie

Senior Vice President & Chief
Financial Officer

Garth R. Doll

Vice President, Marketing

Terry S. Eichinger

Vice President, Drilling,
Completions & Operations
Support

Nathan D. Fisher

Vice President, U.S.
Business Unit

Daniel J. Fitzgerald

Vice President, Business
Development

John E. Hoffman

Vice President, Canadian
Assets & Corporate
Sustainability

David A. McCoy

Vice President, General
Counsel & Corporate
Secretary

Shaina B. Morihira

Vice President, Finance

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
KPMG LLP
Calgary, Alberta

Transfer Agent
AST Trust Company (Canada)/American Stock Transfer & Trust Company, LLC
Calgary, Alberta
Toll free: 1.800.387.0825

Independent Reserves Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. Office
U.S. Bank Tower
Suite 2200, 950 17th Street
Denver, Colorado 80202-2805

Telephone: 720.279.5500
Fax: 720.279.5550

enerPLUS

Enerplus

The Dome Tower
3000, 333 7th Avenue SW
Calgary, Alberta T2P 2Z1
Toll Free 1.800.319.6462
www.enerplus.com
investorrelations@enerplus.com

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE