enerPLUS

First Quarter Report

Three Months Ended March 31, 2020

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2020	2019
Financial (CDN$, thousands, except ratios)		
Net Income	$ 2,876	$ 19,158
Adjusted Net Income(1)	21,089	72,458
Cash Flow from Operating Activities	122,739	108,951
Adjusted Funds Flow(1)	113,227	168,755
Dividends to Shareholders - Declared	6,670	7,162
Total Debt Net of Cash(1)	514,620	363,771
Capital Spending	163,625	160,793
Property and Land Acquisitions	2,256	3,025
Property Divestments	5,578	466
Net Debt to Adjusted Funds Flow Ratio(1)	0.8x	0.5x
Financial per Weighted Average Shares Outstanding		
Net Income - Basic	$ 0.01	$ 0.08
Net Income - Diluted	0.01	0.08
Weighted Average Number of Shares Outstanding (000's) - Basic	222,357	238,922
Weighted Average Number of Shares Outstanding (000's) - Diluted	223,300	241,298
Selected Financial Results per BOE(2)(3)		
Oil & Natural Gas Sales(4)	$ 31.96	$ 44.70
Royalties and Production Taxes	(8.16)	(10.48)
Commodity Derivative Instruments	3.69	1.32
Cash Operating Expenses	(8.84)	(8.75)
Transportation Costs	(3.95)	(3.92)
Cash General and Administrative Expenses	(1.37)	(1.55)
Cash Share-Based Compensation	0.31	(0.17)
Interest, Foreign Exchange and Other Expenses	(0.97)	(0.68)
Current Income Tax Recovery	—	0.69
Adjusted Funds Flow(1)	$ 12.67	$ 21.16

SELECTED OPERATING RESULTS	Three months ended March 31, 2020	2019
Average Daily Production(3)		
Crude Oil (bbls/day)	49,044	41,105
Natural Gas Liquids (bbls/day)	5,346	4,383
Natural Gas (Mcf/day)	262,913	258,568
Total (BOE/day)	98,209	88,583
% Crude Oil and Natural Gas Liquids	55%	51%
Average Selling Price(3)(4)		
Crude Oil (per bbl)	$ 51.30	$ 66.56
Natural Gas Liquids (per bbl)	12.72	19.15
Natural Gas (per Mcf)	2.08	4.38
Net Wells Drilled	34	17

(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 the effects of commodity derivative instruments.

Average Benchmark Pricing	Three months ended March 31, 2020	2019
WTI crude oil (US$/bbl)	$ 46.17	$ 54.90
Brent (ICE) crude oil (US$/bbl)	50.96	63.90
NYMEX natural gas – last day (US$/Mcf)	1.95	3.10
USD/CDN average exchange rate	1.34	1.33

Share Trading Summary For the three months ended March 31, 2020	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 9.55	$ 7.35
Low	$ 1.62	$ 1.15
Close	$ 2.07	$ 1.48

(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

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

NEWS RELEASE

HIGHLIGHTS

- Achieved first quarter production of 98,209 BOE per day, including liquids of 54,390 barrels per day
- Maintained low financial leverage; net debt to adjusted funds flow ratio was 0.8 times at quarter-end
- Strong liquidity with cash of $142 million and an undrawn US$600 million bank credit facility at quarter-end
- Robust commodity hedging position with forecast hedging gains of approximately $150 million in 2020, based on recent forward strip oil prices
- Solid execution resulted in an 11% reduction to well costs year to date in North Dakota, compared to 2019
- Lower expected run rate cash costs driven by workflow improvements and reduced cash compensation for Enerplus' Board of Directors, executives and employees
- Significant operational flexibility to reduce production levels to protect against selling oil at negative margins and preserve shareholder value
- Advantaged position for future capital deployment with 27 net drilled uncompleted wells in inventory in North Dakota

"Under extremely challenging conditions, Enerplus delivered a solid operational quarter which has left the company well positioned to navigate the ongoing market uncertainty," commented Ian C. Dundas, President and Chief Executive Officer of Enerplus. "We remain focused on protecting our people and supporting our communities, while delivering strong safety and operational performance across our business. The decisive actions we have taken over the last few months to reduce spending and lower our cost structure have enhanced our resilience. The resourcefulness of our people has been key to our ability to respond quickly."

RESPONSE TO COVID-19

In response to the coronavirus ("COVID-19") pandemic, Enerplus introduced additional measures to enhance employee and community safety, while ensuring the continuity of its business. The Company directed all staff who are able to work from home to do so, and adopted new working practices through leveraging technology and strong collaboration. At its field operations, Enerplus implemented procedures to allow for effective physical distancing for employees and contractors. Enerplus' senior leadership team has been operating under a dedicated emergency response plan, including increased engagements with the Company's Board of Directors, to address short term needs and plan for longer term business continuity.

FIRST QUARTER SUMMARY

Production

Production in the first quarter of 2020 was 98,209 BOE per day, an increase of 11% compared to the same period a year ago, and 9% lower than the prior quarter. Crude oil and natural gas liquids production in the first quarter of 2020 was 54,390 barrels per day, an increase of 20% compared to the same period a year ago, and 9% lower than the prior quarter. The lower quarter-over-quarter production was due to the Company's 2019 investment profile with limited capital activity in the fourth quarter, along with Enerplus' decision to shut-in, abandon and reclaim its non-core natural gas asset at Tommy Lakes in Canada in the first quarter of 2020.

Financial Highlights

Enerplus reported adjusted funds flow for the first quarter of 2020 of $113.2 million compared to $168.8 million in the first quarter of 2019. The Company reported adjusted net income for the first quarter of 2020 of $21.1 million ($0.09 per share) compared to $72.5 million ($0.30 per share) in the first quarter of 2019. The year-over-year decrease in adjusted funds flow and adjusted net income was due to lower crude oil and natural gas prices in the first quarter of 2020.

Enerplus' first quarter 2020 realized Bakken oil price differential was US$5.26 per barrel below WTI, compared to US$3.25 per barrel below WTI in the first quarter of 2019. The wider Bakken differential was primarily a function of the year-over-year production growth in the basin. The Company's realized Marcellus natural gas price differential was US$0.38 per Mcf below NYMEX during the first quarter of 2020 compared to US$0.13 per Mcf above NYMEX in the first quarter of 2019. The wider year-over-year Marcellus differential was driven by low winter natural gas demand in the first quarter of 2020.

In the first quarter of 2020, Enerplus' operating costs were $8.84 per BOE, transportation costs were $3.95 per BOE and cash general and administrative expenses were $1.37 per BOE.

Exploration and development capital spending in the first quarter was $163.6 million. The Company also spent $2.5 million repurchasing 340,434 shares and paid $6.7 million in dividends during the first quarter. As previously announced, Enerplus has suspended its share repurchase program given the deterioration in market conditions in order to prioritize the Company's financial strength and liquidity.

Enerplus ended the first quarter of 2020 with a strong balance sheet and significant liquidity. The Company had total debt of $656.7 million, cash of $142.1 million and was undrawn on its US$600 million bank credit facility. The Company's net debt to adjusted funds flow ratio was 0.8 times at quarter-end.

Asset Activity

Williston Basin production averaged 49,521 BOE per day (80% oil) during the first quarter of 2020, an increase of 27% compared to the same period a year ago, and 8% lower than the prior quarter. The Company drilled 18 gross operated wells (99% average working interest) and brought 11 gross operated wells (82% average working interest) on production during the first quarter.

The Company's operational performance in North Dakota has tracked ahead of expectations year to date. Drilling cycle times have averaged 11 days per well for 10,000 foot laterals (spud to rig release), with eight of the last 11 wells drilled in 10 days or less. This compares to Enerplus' 2019 average of 12.6 days per well. The Company's 2020 well completion operations have also outperformed expectations. Combined, this strong drilling and completion execution resulted in an average well cost of US$6.8 million year to date, an 11% reduction compared to the Company's 2019 average.

Marcellus production averaged 216 MMcf per day during the first quarter of 2020, an increase of 3% compared to the same period in 2019, and 7% lower than the prior quarter. The Company participated in drilling 15 gross non-operated wells (7% average working interest) and brought 10 gross non-operated wells (4% average working interest) on production during the quarter.

Canadian waterflood production averaged 8,209 BOE per day (94% crude oil) during the first quarter of 2020, a decrease of 12% compared to the same period in 2019, and 4% lower than the prior quarter. The Company drilled 10 producer/injector wells (100% working interest) at its Giltedge field in the first quarter.

OUTLOOK

Enerplus has taken proactive steps to preserve shareholder value as a result of the significant decline in crude oil prices. As previously announced, the Company has reduced its 2020 capital budget by 45%, to $300 million and lowered its cost structure through workflow improvements, vendor service cost reductions, project deferrals and reduced cash compensation for its Board of Directors, executives and employees.

Enerplus also began reducing production levels across its Williston basin and Canadian operations in April to protect against selling oil at negative margins. The Company's April production was approximately 91,500 BOE per day, including 49,700 barrels per day of crude oil and natural gas liquids, exceeding the Company's April outlook. In May, Enerplus began curtailing further production. Currently, the Company estimates that approximately 25% of its liquids volumes are curtailed, which excludes its recently completed seven-well pad in North Dakota that the Company has chosen not to produce until oil prices improve. Based on current regional pricing dynamics, Enerplus does not anticipate curtailing production beyond current levels through the rest of the second quarter.

Capital activity and production expectations in Enerplus' Marcellus natural gas position remain unchanged relative to the Company's original 2020 plans. Enerplus expects its Marcellus production to average approximately 185 to 200 MMcf per day through the remaining three quarters of 2020. The Company also expects its full year 2020 Marcellus natural gas price differential to average US$0.45 per Mcf below NYMEX.

Notwithstanding the potential variability in production levels in 2020 due to curtailments, the Company estimates its 2020 unit operating expenses will average approximately $8.25 per BOE, compared to its original forecast of $8.50 per BOE.

As previously announced, the Company has withdrawn its 2020 corporate guidance as a result of the significant ongoing uncertainty in oil prices.

Enerplus will remain disciplined with its production management and capital allocation during this period of heightened oil price volatility. The Company currently has 27 net operated drilled uncompleted wells in inventory in North Dakota enabling rapid future capital deployment.

Average Daily Production(1)

	Three months ended March 31, 2020			
	Crude Oil (Mbbl/d)	**NGL** (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)
Williston Basin	39.8	4.6	30.8	49.5
Marcellus	—	—	216.0	36.0
Canadian Waterfloods	7.7	0.1	2.6	8.2
Other(2)	1.5	0.7	13.5	4.5
Total	**49.0**	**5.3**	**262.9**	**98.2**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Drilled(1)

	Three months ended March 31, 2020			
	Operated		**Non Operated**	
	Gross	Net	Gross	Net
Williston Basin	18.0	17.9	3.0	1.1
Marcellus	—	—	15.0	1.1
Canadian Waterfloods	10.0	10.0	—	—
Other(2)	5.0	4.4	1.0	—
Total	**33.0**	**32.2**	**19.0**	**2.2**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Brought On-Stream(1)

	Three months ended March 31, 2020			
	Operated		**Non Operated**	
	Gross	Net	Gross	Net
Williston Basin	11.0	9.0	7.0	1.9
Marcellus	—	—	10.0	0.4
Canadian Waterfloods	—	—	—	—
Other(2)	—	—	1.0	—
Total	**11.0**	**9.0**	**18.0**	**2.2**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

PRICE RISK MANAGEMENT

Enerplus has an average of 24,800 barrels per day of crude oil hedged through financial derivative contracts for the remainder of 2020.

In addition to its financial derivative contracts, Enerplus has fixed physical differential sales agreements for approximately 13,000 barrels of oil per day at an estimated price of WTI less US$5.00 per barrel for the remainder of 2020.

Commodity Derivatives (As at May 7, 2020)

	WTI Crude Oil (US$/bbl)(1)(2)		
	Apr 1, 2020 – Jun 30, 2020	**Jul 1, 2020 – Sep 30, 2020**	**Oct 1, 2020 – Dec 31, 2020**
Swaps			
Volume (bbls/d)	9,500	7,000	—
Sold Swaps	$ 57.37	$ 36.02	—
Put Spreads(2)			
Volume (bbls/d)	16,000	16,000	16,000
Sold Puts	$ 46.88	$ 46.88	$ 46.88
Purchased Puts	$ 57.50	$ 57.50	$ 57.50
Three Way Collars(2)			
Volume (bbls/d)	—	5,000	5,000
Sold Puts	—	$ 48.00	$ 48.00
Purchased Puts	—	$ 56.25	$ 56.25
Sold Calls	—	$ 65.00	$ 65.00

(1) The sold puts on the put spreads settle annually at the end of 2020.
(2) The total average deferred premium on outstanding hedges is US$1.67/bbl from April 1, 2020 to December 31, 2020.

Currency and Accounting Principles
All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent
This news release also contains references to "BOE" (barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Presentation of Production Information
Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under Canadian disclosure requirements and industry practice, oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. All production volumes and oil and gas sales presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest. All references to "liquids" in this news release include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release 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 news release contains forward-looking information pertaining to the following: expected capital spending levels in 2020 and impact thereof on our production levels and land holdings; expected production volumes; expected operating strategy in 2020 , including the proportion of Enerplus' production that may be curtailed and the effect of such curtailment on its properties, operations and financial position; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials, our commodity risk management program in 2020 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating costs; our anticipated shares repurchases under future normal course issuer bids; potential future asset and goodwill 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; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes; expectations regarding repayment of our outstanding senior notes, including sources of funds therefor; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2020; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this news release 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; that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment 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; our ability to comply with our debt covenants; the availability of third party services; and the extent of our liabilities. In addition, our expected 2020 capital expenditures and operating strategy described in this news release is based on the rest of the year prices and exchange rate of: a WTI price of US$22.80/bbl, a NYMEX price of US$2.23/Mcf, and a USD/CDN exchange rate of 1.40. 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. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

The forward-looking information included in this news release 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 instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further decline and/or 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; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2019).

The forward-looking information contained in this news release speaks only as of the date of this news release, 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.

NON-GAAP MEASURES

In this news release, we use the terms "adjusted funds flow", "adjusted net income", "net debt to adjusted funds flow ratio" and "total debt net of cash" as measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as cash flow generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Adjusted net income" is calculated as net income adjusted for unrealized derivative instrument gain/loss, unrealized foreign exchange gain/loss, the tax effect of these items and the impact of statutory changes to the Company's corporate tax rate. "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash and cash equivalents, divided by a trailing 12 months of adjusted funds flow. "Total debt net of cash" is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and cash equivalents. Calculation of these terms is described in Enerplus' MD&A under the "Non-GAAP Measures" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "adjusted net income", "net debt to adjusted funds flow", and "total debt net of cash" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' First Quarter 2020 MD&A.

Electronic copies of Enerplus Corporation's First Quarter 2020 MD&A and Financial Statements, along with other public information including investor presentations, are available on its website at www.enerplus.com. Shareholders may, upon request, receive a printed copy of the Company's audited financial statements at any time. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated May 7, 2020 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2020 and 2019 (the "Interim Financial Statements");

- the audited consolidated financial statements of Enerplus as at December 31, 2019 and 2018 and for the years ended December 31, 2019, 2018 and 2017; and

- our MD&A for the year ended December 31, 2019 (the "Annual MD&A").

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 the MD&A for further information. In addition, the following MD&A contains disclosure regarding certain risks and uncertainties associated with Enerplus' business. See "Risk Factors and Risk Management" in this MD&A and in the Annual MD&A and "Risk Factors" in Enerplus' annual information form for the year ended December 31, 2019 (the "Annual Information Form").

BASIS OF PRESENTATION

The Interim Financial Statements and Notes thereto have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim 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 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. BOE and Mcfe measures 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. Unless otherwise stated, all production volumes and realized product prices information is 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. 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 references to "liquids" in this MD&A include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

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

OVERVIEW

The coronavirus ("COVID-19") pandemic and global excess supply of crude oil have created unprecedented market volatility and significant challenges for our industry. Government and health authorities' efforts to slow the spread of the virus have resulted in a sudden contraction of the global economy, causing a significant reduction in crude oil demand. At the same time, the initial failure of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations to agree on production restrictions in early March led to a dramatic increase in global crude oil supply. This resulted in a decrease of approximately 50% in WTI benchmark prices in March to US$30.45/bbl compared to average December prices of US$59.80/bbl. These events also led to indiscriminate downward pressure on energy equities, resulting in a 78% decline in our share price at March 31, 2020 compared to December 31, 2019. In response, on April 22, 2020, we issued a news release withdrawing our 2020 corporate guidance provided in the news release dated March 16, 2020 and included in our Annual MD&A dated February 20, 2020. We will continue to reassess our ability to reasonably estimate and provide annual guidance and plan to provide additional operational updates to our investors during this period of heightened volatility.

Despite the challenging market conditions, we are focused on preserving our balance sheet and maintaining our liquidity. At March 31, 2020, total debt net of cash was $514.6 million, including senior notes of $656.7 million and cash on hand of $142.1 million, and our net debt to adjusted funds flow ratio was 0.8x. At March 31, 2020 and as of the date of this MD&A, we were undrawn on our US$600 million bank credit facility and we are compliant with all debt covenants.

Production for the first quarter of 2020 averaged 98,209 BOE/day, a 9% decrease compared to production of 107,436 BOE/day in the fourth quarter of 2019. Production decreased in North Dakota as expected due to modest capital spending in the fourth quarter, primarily focused on drilling activity. Natural gas production also decreased with limited capital spending in both the fourth quarter of 2019 and the first quarter of 2020. Natural gas volumes were further impacted by our decision during the first quarter to shut-in, abandon and reclaim our non-core natural gas assets at Tommy Lakes in Canada.

Beginning in April 2020, we have temporarily shut-in select wells across the Williston basin and our Canadian waterfloods to protect against selling crude oil at negative margins. Our April production was approximately 91,500 BOE/day, including 49,700 bbls/day of crude oil and natural gas liquids, exceeding our expected April production of 88,000 BOE/day including 47,000 bbls/day of crude oil and natural gas liquids. In May, we began curtailing further production. Currently, we estimate that approximately 25% of our crude oil and natural gas liquids volumes are curtailed, which excludes our recently completed seven-well pad in North Dakota that we have chosen not to produce until oil prices improve. Based on current quarter regional pricing dynamics, we do not anticipate curtailing production beyond current levels through the rest of the second quarter.

Capital activity and production expectations for our Marcellus natural gas position remain unchanged relative to our original 2020 plans. We expect Marcellus production to average approximately 185 MMcf/day to 200 MMcf/day for the remainder of the year.

Our Bakken crude oil price differential widened to US$5.26/bbl below WTI during the first quarter, compared to US$4.40/bbl below WTI in the fourth quarter of 2019, due to regional production remaining above pipeline takeaway capacity. We have fixed physical differential sales agreements in place for the remainder of 2020 for approximately 13,000 bbls/day of crude oil in North Dakota at an estimated price of WTI less US$5.00/bbl. Our Marcellus natural gas price differential narrowed to US$0.38/Mcf below NYMEX during the first quarter from US$0.63/Mcf below NYMEX in the fourth quarter of 2019 due to increased seasonal demand in the region. We continue to expect our Marcellus natural gas price differential to average US$0.45/Mcf below NYMEX in 2020.

We expect our commodity hedging program to protect a significant portion of our cash flow from operating activities and adjusted funds flow. At March 31, 2020, our crude oil commodity derivative contracts were in a net asset position of $108.4 million and we expect our commodity hedging position to provide full year gains of approximately $150 million based on recent forward strip oil prices. As of May 7, 2020, we had approximately 24,800 bbls/day of crude oil hedged for the remainder of 2020.

Capital expenditures totaled $163.6 million during the first quarter, with approximately 95% of capital spending directed to crude oil properties in North Dakota, the DJ Basin and the Canadian waterfloods.

We have reduced our expected capital spending to $300 million through the suspension of all further drilling and completions activity in North Dakota, efficiency improvements and the deferral of certain non-operated oil activity. In total, we have reduced our 2020 capital spending budget by approximately 45% from our original guidance range of $520 million to $570 million.

Operating costs for the quarter were $79.0 million, or $8.84/BOE, compared to $79.5 million, or $8.05/BOE, in the fourth quarter of 2019 mainly due to lower production in the first quarter of 2020. We have reduced our expected average annual operating costs to $8.25/BOE from our previous guidance of $8.50/BOE through further project prioritization and service cost reductions.

We reported net income of $2.9 million in the first quarter of 2020 compared to a net loss of $429.1 million in the fourth quarter of 2019. The increase was primarily the result of a $451.1 million non-cash goodwill impairment recorded in the fourth quarter of 2019 and a $131.3 million gain on commodity derivative instruments recorded in the first quarter of 2020. Net income in the first quarter was also impacted by a $93.6 million valuation allowance recorded against a portion of our Canadian deferred income tax assets.

During the first quarter of 2020, cash flow from operations decreased to $122.7 million, compared to $188.5 million in the fourth quarter of 2019, and adjusted funds flow decreased to $113.2 million from $178.9 million in the same respective periods. The decreases were the result of lower production and a decline in realized prices, offset by higher realized commodity derivative gains in the first quarter.

During the quarter, we repurchased and cancelled 340,434 common shares for total consideration of $2.5 million under our Normal Course Issuer Bid ("NCIB") prior to its expiry on March 25, 2020. Given the deterioration in market conditions, we have suspended our share repurchase program to prioritize our financial strength and liquidity. We plan to renew our NCIB in due course and recommence our share repurchase program when market conditions improve.

RESULTS OF OPERATIONS

Production

Daily production for the first quarter averaged 98,209 BOE/day, a decrease of 9% compared to average production of 107,436 BOE/day in the fourth quarter of 2019. Crude oil and natural gas liquids production decreased by 5,456 bbls/day primarily due to the timing of our 2019 capital program, with lower capital spending in the fourth quarter. Natural gas production decreased 8% to 262,913 Mcf/day in the first quarter of 2020 from 285,537 Mcf/day in the fourth quarter of 2019 due to limited capital activity in the Marcellus and our decision to shut-in, abandon and reclaim Tommy Lakes, a Canadian asset with approximately 1,600 BOE/day (90% natural gas) of average annual production.

For the three months ended March 31, 2020, total production increased by 11%, when compared to the same period in 2019. The increase in production was primarily due to a 29% increase in U.S. crude oil and natural gas liquids production as a result of our continued capital investment in North Dakota.

Our crude oil and natural gas liquids weighting increased to 55% in the first quarter of 2020 from 51% for the same period in 2019.

Average daily production volumes for the three months ended March 31, 2020 and 2019 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2020**	**2019**	**% Change**
Crude oil (bbls/day)	49,044	41,105	19%
Natural gas liquids (bbls/day)	5,346	4,383	22%
Natural gas (Mcf/day)	262,913	258,568	2%
Total daily sales (BOE/day)	98,209	88,583	11%

As announced in our April 22, 2020 news release, we have withdrawn our annual production guidance due to ongoing uncertainty in market conditions. Daily production in April was modestly impacted by shut-ins, with monthly average production of approximately 91,500 BOE/day, including 49,700 bbls/day of crude oil and natural gas liquids, exceeding our expected April average production of 88,000 BOE/day including 47,000 bbls/day of crude oil and natural gas liquids. In May, we began curtailing further production. Currently, we estimate that approximately 25% of our crude oil and natural gas liquids volumes are curtailed, which excludes our recently completed seven-well pad in North Dakota that we have chosen not to produce until oil prices improve. Based on current regional pricing dynamics, we do not anticipate curtailing production beyond current levels through the rest of the second quarter.

Capital activity and production expectations for our Marcellus natural gas position remain unchanged relative to our original 2020 plans. We expect Marcellus production to average approximately 185 MMcf/day to 200 MMcf/day for the remainder of the year.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operations, adjusted funds flow and financial condition. The following table compares quarterly average prices for the three months ended March 31, 2020 and 2019 and other periods indicated:

Pricing (average for the period)	**Q1 2020**	**Q4 2019**	**Q3 2019**	**Q2 2019**	**Q1 2019**
Benchmarks					
WTI crude oil (US$/bbl)	$ 46.17	$ 56.96	$ 56.45	$ 59.81	$ 54.90
Brent (ICE) crude oil (US$/bbl)	50.96	62.51	62.00	68.32	63.90
NYMEX natural gas – last day (US$/Mcf)	1.95	2.50	2.23	2.64	3.15
USD/CDN average exchange rate	1.34	1.32	1.32	1.34	1.33
USD/CDN period end exchange rate	1.41	1.30	1.32	1.31	1.33
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 51.30	$ 67.23	$ 67.76	$ 74.42	$ 66.56
Natural gas liquids ($/bbl)	12.72	18.28	5.97	17.96	19.15
Natural gas ($/Mcf)	2.08	2.50	2.13	2.63	4.38
Average differentials					
Bakken DAPL – WTI (US$/bbl)	$ (5.34)	$ (5.59)	$ (2.97)	$ (2.36)	$ (2.93)
Brent (ICE) – WTI (US$/bbl)	4.79	5.55	5.55	8.51	9.00
MSW Edmonton – WTI (US$/bbl)	(7.58)	(5.37)	(4.66)	(4.63)	(4.85)
WCS Hardisty – WTI (US$/bbl)	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.39)	(0.70)	(0.48)	(0.43)	(0.22)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.41	(0.11)	(0.35)	(0.31)	1.67
Enerplus realized differentials(1)(2)					
Bakken crude oil – WTI (US$/bbl)	$ (5.26)	$ (4.40)	$ (3.61)	$ (3.00)	$ (3.25)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.38)	(0.63)	(0.44)	(0.57)	0.13
Canada crude oil – WTI (US$/bbl)	(17.77)	(14.80)	(13.50)	(9.99)	(10.42)

(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

Our realized crude oil sales price for the first quarter of 2020 averaged $51.30/bbl, a decrease of 24% compared to the fourth quarter of 2019 due to weaker benchmark prices and wider realized price differentials for our production. Benchmark WTI prices fell by 19% over the same period due to the combined impact of the global demand destruction resulting from the COVID-19 pandemic and the dramatic increase in the supply of Russian and Saudi Arabian crude oil in the markets after the OPEC+ nations failed to agree on production restrictions in early March 2020.

Our realized Bakken price differential weakened by US$0.86/bbl during the quarter to average US$5.26/bbl below WTI due to regional production remaining above pipeline takeaway capacity and a lower volume of crude oil sold under fixed price differential contracts compared to the fourth quarter of 2019. Our Bakken sales price consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI and/or Brent, and sales at the U.S. Gulf Coast delivered via firm capacity on the Dakota Access Pipeline. A portion of our physical sales are directly tied to the spread between Brent and WTI crude oil prices. That differential narrowed by US$0.76/bbl, during the quarter, which resulted in a weaker realized price for a portion of our production. For the remainder of 2020, we have fixed physical differential sales agreements in North Dakota for approximately 13,000 bbls/day at an estimated price of WTI less US$5.00/bbl.

Our realized price differential for Canadian crude oil production widened by US$2.97/bbl compared to the fourth quarter of 2019, which was in line with changes to the underlying benchmark prices for Canadian crude oil.

Our realized sales price for natural gas liquids averaged $12.72/bbl during the first quarter of 2020, a 30% decrease compared to the previous quarter mainly due to the decrease in the WTI benchmark price, with a significant portion of our natural gas liquids contracts tied to WTI pricing.

NATURAL GAS

Our realized natural gas sales price decreased by 17% during the quarter to average $2.08/Mcf. NYMEX benchmark prices fell 22% over the same period due to warmer than average weather across the U.S. resulting in significant price weakness throughout the first quarter. Our realized Marcellus sales price differential averaged US$0.38/Mcf below NYMEX during the quarter, compared to US$0.63/Mcf in the fourth quarter of 2019, reflecting seasonal strength in local market price differentials over the period. A significant portion of our production receives prices reflecting market conditions south of New York. Prices for Transco Zone 6 Non-New York averaged US$0.41/Mcf over NYMEX in the first quarter, and this seasonal strength helped improve our overall realized price for our Marcellus production. We continue to expect our Marcellus natural gas price differential to average US$0.45/Mcf below NYMEX in 2020.

FOREIGN EXCHANGE

Our 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 weaker Canadian dollar increases the amount of our realized sales, as well as the amount of our U.S. denominated costs, such as capital, interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes.

The Canadian dollar weakened significantly near the end of the first quarter of 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 Canadian dollar weakened to 1.41 USD/CDN at March 31, 2020, compared to 1.30 USD/CDN at December 31, 2019. The average exchange rate during the first quarter remained consistent compared to the same period of the prior year, averaging 1.34 USD/CDN compared to 1.33 USD/CDN in the first quarter of 2019.

Price Risk Management

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

As of May 7, 2020, we have hedged 24,800 bbls/day of crude oil for the remainder of 2020. Our crude oil hedges are a mix of swaps, put spreads and three way collars. The put spreads and three way collars provide us with exposure to significant upwards price movement; 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. Overall, we expect our crude oil related hedging contracts to protect a significant portion of our cash flow from operating activities and adjusted funds flow.

The following is a summary of our financial contracts in place at May 7, 2020:

	WTI Crude Oil (US$/bbl)		
	Apr 1, 2020 – Jun 30, 2020	**Jul 1, 2020 – Sep 30, 2020**	**Oct 1, 2020 – Dec 31, 2020**
Swaps			
Volume (bbls/day)	9,500	7,000	—
Sold Swaps	$ 57.37	$ 36.02	—
Put Spreads(1)			
Volume (bbls/day)	16,000	16,000	16,000
Sold Puts(2)	$ 46.88	$ 46.88	$ 46.88
Purchased Puts	$ 57.50	$ 57.50	$ 57.50
Three Way Collars(1)			
Volume (bbls/day)	—	5,000	5,000
Sold Puts	—	$ 48.00	$ 48.00
Purchased Puts	—	$ 56.25	$ 56.25
Sold Calls	—	$ 65.00	$ 65.00

(1) The total average deferred premium spent on our outstanding hedges is US$1.67/bbl from April 1, 2020 to December 31, 2020.
(2) The sold puts on the put spreads settle annually at the end of 2020.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Cash gains/(losses):		
Crude oil	$ 33.0	$ (2.0)
Natural gas	—	12.5
Total cash gains/(losses)	$ 33.0	$ 10.5
Non-cash gains/(losses):		
Crude oil	$ 98.3	$ (86.9)
Natural gas	—	(8.5)
Total non-cash gains/(losses)	$ 98.3	$ (95.4)
Total gains/(losses)	$ 131.3	$ (84.9)

	Three months ended March 31,	
(Per BOE)	**2020**	**2019**
Total cash gains/(losses)	$ 3.69	$ 1.32
Total non-cash gains/(losses)	11.01	(11.97)
Total gains/(losses)	$ 14.70	$ (10.65)

We realized cash gains of $33.0 million on our crude oil contracts during the first quarter of 2020, compared to realized cash losses of $2.0 million for the same period in 2019. Cash gains on crude oil contracts in the first quarter of 2020 were primarily due to prices falling below the swap level and the put strike price on our put spreads and three way collars. Our natural gas contracts were settled in the fourth quarter of 2019 and there were no natural gas derivative contracts outstanding during the first quarter of 2020. In comparison, we realized cash gains of $12.5 million on our natural gas contracts during the first quarter of 2019.

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. At March 31, 2020, the fair value of crude oil contracts was in a net asset position of $108.4 million. For the three months ended March 31, 2020, the change in the fair value of our crude oil contracts resulted in a gain of $98.3 million, compared to a $86.9 million loss during the same period in 2019. We had no natural gas derivative contracts outstanding at March 31, 2020. In comparison, we recorded a non-cash loss of $8.5 million on our natural gas contracts during the first quarter of 2019.

Revenues

	Three months ended March 31,	
($ millions)	**2020**	**2019**
Oil and natural gas sales	$ 285.6	$ 356.4
Royalties	(57.5)	(68.9)
Oil and natural gas sales, net of royalties	$ 228.1	$ 287.5

Oil and natural gas sales, net of royalties, for the three months ended March 31, 2020 were $228.1 million, a decrease of 21% from the same period in 2019. The decrease in revenue was a result of lower realized prices partially offset by higher production volumes when compared to the same period in 2019. See Note 11 to the Interim Financial Statements for further detail.

Royalties and Production Taxes

	Three months ended March 31,	
($ millions, except per BOE amounts)	**2020**	**2019**
Royalties	$ 57.5	$ 68.9
Per BOE	$ 6.43	$ 8.65
Production taxes	$ 15.4	$ 14.6
Per BOE	$ 1.73	$ 1.83
Royalties and production taxes	$ 72.9	$ 83.5
Per BOE	$ 8.16	$ 10.48
Royalties and production taxes (% of oil and natural gas sales)	26%	23%

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 for the three months ended March 31, 2020 were $72.9 million, a decrease of 13% from the same period in 2019. The decrease was primarily due to lower realized prices, which more than offset the increase in production.

Operating Expenses

	Three months ended March 31,	
($ millions, except per BOE amounts)	2020	2019
Cash operating expenses	$ 79.0	$ 69.8
Per BOE	$ 8.84	$ 8.75

For the three months ended March 31, 2020, operating expenses were $79.0 million or $8.84/BOE, an increase of $9.2 million or $0.09/BOE from the same period in 2019. The increase was mainly due to higher crude oil and natural gas liquids production, with our liquids weighting increasing to 55% from 51% over the same period.

As announced in our April 22, 2020 news release, we have reduced our expected average annual operating costs to $8.25/BOE from previous guidance of $8.50/BOE due to expected cost savings.

Transportation Costs

	Three months ended March 31,	
($ millions, except per BOE amounts)	2020	2019
Transportation costs	$ 35.3	$ 31.3
Per BOE	$ 3.95	$ 3.92

For the three months ended March 31, 2020, transportation costs were $35.3 million or $3.95/BOE, an increase of $4.0 million from the same period in 2019. The increase was primarily due to growth in U.S. crude oil and natural gas liquids production over the same period.

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.

	Three months ended March 31, 2020		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	59,226 BOE/day	233,898 Mcfe/day	98,209 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 44.46	$ 2.16	$ 31.96
Royalties and production taxes	(11.94)	(0.40)	(8.16)
Cash operating expenses	(13.35)	(0.33)	(8.84)
Transportation costs	(2.92)	(0.92)	(3.95)
Netback before hedging	$ 16.25	$ 0.51	$ 11.01
Cash hedging gains/(losses)	6.12	—	3.69
Netback after hedging	$ 22.37	$ 0.51	$ 14.70
Netback before hedging ($ millions)	$ 87.6	$ 10.8	$ 98.4
Netback after hedging ($ millions)	$ 120.6	$ 10.8	$ 131.4

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

Netbacks by Property Type	Three months ended March 31, 2019 Crude Oil	Natural Gas	Total
Average Daily Production	48,909 BOE/day	238,044 Mcfe/day	88,583 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 59.51	$ 4.41	$ 44.70
Royalties and production taxes	(14.92)	(0.83)	(10.48)
Cash operating expenses	(13.96)	(0.39)	(8.75)
Transportation costs	(2.75)	(0.90)	(3.92)
Netback before hedging	$ 27.88	$ 2.29	$ 21.55
Cash hedging gains/(losses)	(0.45)	0.59	1.32
Netback after hedging	$ 27.43	$ 2.88	$ 22.87
Netback before hedging ($ millions)	$ 122.7	$ 49.1	$ 171.8
Netback after hedging ($ millions)	$ 120.8	$ 61.5	$ 182.3

(1) See “Non-GAAP Measures” in this MD&A

Total netbacks before hedging for the three months ended March 31, 2020 were lower compared to the same period in 2019 primarily due to weaker realized prices.

For the three months ended March 31, 2020, our crude oil properties accounted for 89% of our total netback before hedging, compared to 71% during the same period in 2019.

General and Administrative (“G&A”) Expenses

Total G&A expenses include share-based compensation (“SBC”) charges related to our long-term incentive plans (“LTI plans”). See Note 12 and Note 15 to the Interim Financial Statements for further details.

($ millions)	Three months ended March 31, 2020	2019
Cash:		
G&A expense	$ 12.2	$ 12.3
Share-based compensation expense	(2.7)	1.3
Non-Cash:		
Share-based compensation expense	7.7	8.1
Equity swap loss/(gain)	1.9	(0.1)
G&A expense	0.1	0.1
Total G&A expenses	$ 19.2	$ 21.7

(Per BOE)	Three months ended March 31, 2020	2019
Cash:		
G&A expense	$ 1.37	$ 1.55
Share-based compensation expense	(0.31)	0.17
Non-Cash:		
Share-based compensation expense	0.86	1.01
Equity swap loss/(gain)	0.21	(0.01)
G&A expense	0.01	0.01
Total G&A expenses	$ 2.14	$ 2.73

Cash G&A expenses for the three months ended March 31, 2020 were $12.2 million, or $1.37/BOE, compared to $12.3 million, or $1.55/BOE, for the same period in 2019. Cash G&A expenses were consistent with the same period in 2019 but decreased on a per BOE basis due to higher production.

During the first quarter of 2020, we reported a cash SBC recovery of $2.7 million compared to an expense of $1.3 million for the same period in 2019. The recovery was due to the decrease in our share price on outstanding deferred share units. Non-cash SBC expense for the three months ended March 31, 2020 was $7.7 million, or $0.86/BOE, a decrease from an expense of $8.1 million, or $1.01/BOE, during the same period in 2019.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the first quarter of 2020, we recorded a mark-to-market loss of $1.9 million on these contracts, compared to a gain of $0.1 million in the same period in 2019.

Subsequent to the quarter, we reduced cash compensation for our Board of Directors, executives and employees. Including additional non-salary cost reductions, we anticipate cash G&A expenses will be approximately $5 million lower than our original 2020 budget.

Interest Expense

For the three months ended March 31, 2020, we recorded total interest expense of $8.9 million, compared to $8.4 million for the same period in 2019. The increase in interest expense in the first quarter of 2020 was primarily due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest expense.

At March 31, 2020, we were undrawn on our US$600 million bank credit facility and our debt balance consisted of fixed interest rate senior notes, with a weighted average interest rate of 4.7%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

	Three months ended March 31,	
($ millions)	2020	2019
Realized foreign exchange (gain)/loss:		
Foreign exchange (gain)/loss on settlements	$ (0.1)	$ (0.1)
Translation of U.S. dollar cash held in Canada (gain)/loss	(3.1)	5.2
Unrealized foreign exchange (gain)/loss	(2.4)	(17.1)
Total foreign exchange (gain)/loss	$ (5.6)	$ (12.0)
USD/CDN average exchange rate	1.34	1.33
USD/CDN period end exchange rate	1.41	1.33

For the three months ended March 31, 2020, we recorded a foreign exchange gain of $5.6 million compared to $12.0 million for the same period in 2019. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies along with the translation of our U.S. dollar denominated cash held in Canada, while unrealized foreign exchange gains and losses are recorded on the translation of our U.S dollar denominated working capital held in Canada at each period end.

Effective January 1, 2020, we have designated US$467.0 million of 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 March 31, 2020, Other Comprehensive Income/(Loss) included an unrealized loss of $50.1 million on our outstanding U.S. dollar denominated senior notes (March 31, 2019 – $14.1 million unrealized foreign exchange gain included in net income). The unrealized foreign exchange gain of $2.4 million at March 31, 2020 related to the translation of U.S. dollar denominated working capital held in Canada. See Note 3(a) to the Interim Financial Statements for further details.

Capital Investment

	Three months ended March 31,	
($ millions)	2020	2019
Capital spending(1)	$ 163.6	$ 160.8
Office capital(1)	1.9	1.1
Line fill	—	5.1
Sub-total	165.5	167.0
Property and land acquisitions	$ 2.3	$ 3.0
Property divestments	(5.6)	(0.5)
Sub-total	(3.3)	2.5
Total	$ 162.2	$ 169.5

(1) Excludes changes in non-cash investing working capital. See Note 18(b) to the Interim Financial Statements for further details.

Capital spending for the three months ended March 31, 2020 totaled $163.6 million compared to $160.8 million for the same period in 2019. During the first quarter of 2020, we spent $145.0 million on our U.S. crude oil properties, $6.8 million on our Marcellus natural gas assets and $11.7 million on our Canadian waterflood properties.

During the first quarter, we completed $2.3 million in property and land acquisitions, which included minor acquisitions of leases and undeveloped land, compared to $3.0 million for the same period in 2019. Property divestments for the three months ended March 31, 2020 were $5.6 million compared to $0.5 million for the same period in 2019.

As announced on April 22, 2020, we have reduced our expected 2020 annual capital spending by an additional $25 million to $300 million to further preserve our balance sheet and liquidity position as a result of low crude oil prices. In total, we have decreased our 2020 capital budget by approximately 45% from our original guidance range.

Depletion, Depreciation and Accretion (“DD&A”)

	Three months ended March 31,	
($ millions, except per BOE amounts)	2020	2019
DD&A expense	$ 95.2	$ 75.9
Per BOE	$ 10.65	$ 9.52

DD&A of property, plant and equipment (“PP&E”) is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2020, DD&A increased compared to the same period in 2019 as a result of additional U.S. production with higher depletion rates.

Impairment

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). 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. There have been no PP&E impairments recorded in the current or prior year. See Note 6 to the Interim Financial Statements for trailing twelve month prices.

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 remainder of 2020, 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. We expect the twelve month trailing crude oil prices to decline further in 2020, impacting the ceiling value and increasing the risk of future PP&E impairments. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill" in the Annual MD&A and "Risk Factors and Risk Management" in this MD&A.

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 relates to U.S. operations fluctuates 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.

There was no goodwill impairment recorded during the first quarter of 2020 or the same period of the prior year. At March 31, 2020, we reported $210.0 million of goodwill related to our U.S. reporting unit. There is a risk of future goodwill impairments if commodity prices continue to weaken or there is a downward revision to reserves. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill" in the Annual MD&A and "Risk Factors and Risk Management" in this MD&A.

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 the Condensed Consolidated 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, using a weighted average credit-adjusted risk-free rate of 5.35%, to be $146.1 million at March 31, 2020, compared to $138.0 million at December 31, 2019, using a weighted average credit-adjusted risk-free rate of 5.50%. For the three months ended March 31, 2020, asset retirement obligation settlements were $10.8 million compared to $5.4 million during the same period in 2019. See Note 9 to the Interim Financial Statements for further details.

Leases

Enerplus recognizes right-of-use ("ROU") assets and lease liabilities on the Condensed 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 are based on the present value of lease payments over the lease term. Total ROU assets represent our right to use an underlying asset for the lease term. At March 31, 2020, our total lease liability was $51.4 million. In addition, ROU assets of $46.6 million were recorded, which equate to our lease liabilities less lease incentives. See Note 10 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended March 31, 2020	2019
Current tax expense/(recovery)	$ —	$ (5.5)
Deferred tax expense/(recovery)	109.4	(17.9)
Total tax expense/(recovery)	$ 109.4	$ (23.4)

We recorded a total tax expense of $109.4 million for the period ending March 31, 2020, compared to a recovery of $23.4 million for the same period in 2019. The expense in 2020 relates to higher income in the first quarter of 2020, primarily resulting from unrealized commodity derivative gains and a valuation allowance of $93.6 million recorded against a portion of our Canadian deferred income tax assets. No valuation allowance was recorded against our U.S. deferred income tax assets.

We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will not be realized. We have considered available positive and negative evidence, including future taxable income and reversing existing temporary differences, in making this assessment. 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 a risk of additional valuation allowances in future periods if commodity prices weaken or other evidence indicates that more of our deferred income tax assets will not be realized. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill" in the Annual MD&A and "Risk Factors and Risk Management" in this MD&A. After recording the valuation allowance, our overall net deferred income tax asset was $273.0 million at March 31, 2020 (December 31, 2019 - $372.5 million).

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess 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 under our bank credit facility and senior notes, 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 March 31, 2020, our senior debt to adjusted EBITDA ratio was 1.0x and our net debt to adjusted funds flow ratio was 0.8x. 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 liquidity.

At March 31, 2020, we had $142.1 million of cash on hand and an undrawn US$600 million bank credit facility. Total debt net of cash at March 31, 2020, was $514.6 million, an increase of 13% compared to $455.0 million at December 31, 2019. The increase when compared to December 31, 2019 was primarily a result of the impact of a weaker Canadian dollar at March 31, 2020 on our U.S. dollar denominated senior notes. We have near-term debt maturities of US$82 million in senior notes due in May and June 2020, which we intend to repay with cash on hand, and our remaining maturities extend to 2026.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 152% for the three months ended March 31, 2020, compared to 103% for the same period in 2019.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $270.9 million at March 31, 2020, from $210.4 million at December 31, 2019. We expect to finance our working capital deficit and our ongoing working capital requirements through cash on hand, cash flow from operations and our bank credit facility. We expect to be able to meet our financial commitments, as disclosed under “Commitments” in the Annual MD&A.

During the first quarter, we repurchased and cancelled 340,434 common shares for total consideration of $2.5 million under our Normal Course Issuer Bid (“NCIB”), prior to its expiry on March 25, 2020. Given the current environment, we have chosen not to renew our NCIB in order to conserve capital and preserve our balance sheet strength. We plan to renew our NCIB in due course and recommence our share repurchase program when market conditions improve.

At March 31, 2020, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. We expect to manage our business within these financial ratios during 2020; however, current commodity prices have created a significant level of uncertainty which may challenge this expectation. If we exceed or anticipate exceeding our covenants, we may be required to repay, refinance or renegotiate the terms of the debt. See "Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief" in the Annual Information Form and "Risk Factors and Risk Management" in this MD&A. Our bank credit facility and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

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

Covenant Description		March 31, 2020
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.0x
Total debt to adjusted EBITDA (1)	4.0x	1.0x
Total debt to capitalization	55%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.0x
Senior debt to consolidated present value of total proved reserves(3)	60%	21%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	19.2x

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, impairment 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 March 31, 2020 was $125.3 million and $659.4 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%.

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2020	2019
Dividends to shareholders(1)	$ 6.7	$ 7.2
Per weighted average share (Basic)	$ 0.03	$ 0.03

(1) Excludes changes in non-cash financing working capital. See Note 18(b) to the Interim Financial Statements for further details.

During the three months ended March 31, 2020, we reported total dividends of $6.7 million or $0.03 per share compared to $7.2 million or $0.03 per share for the same period in 2019. Dividends to shareholders have decreased compared to the same period in 2019 as a result of our share repurchase program.

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

Shareholders' Capital

	Three months ended March 31, 2020	2019
Share capital ($ millions)	$ 3,097.2	$ 3,317.9
Common shares outstanding (thousands)	222,564	238,243
Weighted average shares outstanding – basic (thousands)	222,357	238,922
Weighted average shares outstanding – diluted (thousands)	223,300	241,298

For the three months ended March 31, 2020, a total of 2,044,718 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2019 – 1,007,234). In total, 1,160,000 shares were issued from treasury and $13.8 million was transferred from paid-in capital to share capital (2019 – 564,000; $4.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2020 – $7.2 million, 2019 – $5.0 million).

During the three months ended March 31, 2020, the Company 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 – 1,732,038; $19.8 million). Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit (2019 – $24.1 million; $4.3 million). Given the current environment, we chose not to renew our NCIB in order to preserve capital and maintain our balance sheet strength and liquidity.

At May 7, 2020, we had 222,563,267 common shares outstanding. In addition, an aggregate of 6,905,615 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU") and Restricted Share Unit plans assuming the maximum performance multiplier of 2.0 times for the PSUs.

For further details, see Note 15 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2020			Three months ended March 31, 2019		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,836	41,208	49,044	8,998	32,107	41,105
Natural gas liquids (bbls/day)	710	4,636	5,346	984	3,399	4,383
Natural gas (Mcf/day)	14,913	248,000	262,913	24,348	234,220	258,568
Total average daily production (BOE/day)	11,032	87,177	98,209	14,040	74,543	88,583
Pricing[2]						
Crude oil (per bbl)	$ 38.78	$ 53.68	$ 51.30	$ 59.07	$ 68.66	$ 66.56
Natural gas liquids (per bbl)	23.90	11.01	12.72	35.89	14.30	19.15
Natural gas (per Mcf)	2.18	2.07	2.08	4.64	4.35	4.38
Capital Expenditures						
Capital spending	$ 11.8	$ 151.8	$ 163.6	$ 17.5	$ 143.3	$ 160.8
Acquisitions	1.1	1.2	2.3	1.0	2.0	3.0
Divestments	—	(5.6)	(5.6)	(0.1)	(0.4)	(0.5)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 32.8	$ 252.8	$ 285.6	$ 61.8	$ 294.6	$ 356.4
Royalties	(5.7)	(51.8)	(57.5)	(8.9)	(60.0)	(68.9)
Production taxes	(0.3)	(15.1)	(15.4)	(0.6)	(14.0)	(14.6)
Cash operating expenses	(17.5)	(61.5)	(79.0)	(21.0)	(48.8)	(69.8)
Transportation costs	(2.1)	(33.2)	(35.3)	(2.7)	(28.6)	(31.3)
Netback before hedging	$ 7.2	$ 91.2	$ 98.4	$ 28.6	$ 143.2	$ 171.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (131.3)	$ —	$ (131.3)	$ 84.9	$ —	$ 84.9
Total G&A[4]	(0.3)	19.5	19.2	13.2	8.5	21.7
Current income tax expense/(recovery)	—	—	—	—	(5.5)	(5.5)

(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 expense.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2020				
First Quarter	$ 228.1	$ 2.9	$ 0.01	$ 0.01
Total 2020	$ 228.1	$ 2.9	$ 0.01	$ 0.01
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)
2018				
Fourth Quarter	$ 326.7	$ 249.4	$ 1.03	$ 1.02
Third Quarter	373.6	86.9	0.35	0.35
Second Quarter	327.4	12.4	0.05	0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 1,292.7	$ 378.3	$ 1.55	$ 1.53

Oil and natural gas sales, net of royalties, decreased during the first quarter of 2020 compared to the fourth quarter of 2019 due to lower realized prices. Net income increased to $2.9 million during the first quarter of 2020 compared to a net loss of $429.1 million in the fourth quarter of 2019. The increase was primarily the result of a $451.1 million non-cash goodwill impairment recorded in the fourth quarter of 2019 and a $131.3 million gain on commodity derivative instruments recorded in the first quarter of 2020. Net income in the first quarter of 2020 was also impacted by a $93.6 million valuation allowance recorded against a portion of our Canadian deferred income tax assets.

Oil and natural gas sales, net of royalties, in 2019 were essentially flat when compared to 2018 due to lower realized commodity prices, offset by increased production. 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 and a loss on commodity derivative instruments of $66.1 million compared to a gain of $88.2 million recorded in 2018.

RISK FACTORS AND RISK MANAGEMENT

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

The recent COVID-19 pandemic and governmental authorities response thereto has resulted in, and may continue 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; business closures and travel bans; an overall slowdown in the global economy; and political and economic instability. In particular, the COVID-19 pandemic has resulted in, and may continue 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 as a result of the failure by OPEC+ nations to set and maintain production restrictions in early March 2020 and decreased global demand due to the COVID-19 pandemic, have caused significant weakness and volatility in commodity prices. With the rapid spread of the COVID-19 pandemic and additional crude oil supply, the price of crude oil and other petroleum products has deteriorated significantly and, notwithstanding recent agreements among OPEC+ nations to reduce production levels, is expected to remain under pressure and be volatile. The overall result of these recent events and conditions could lead to a prolonged period of depressed prices for crude oil and natural gas. In response to the current decreased crude oil and natural gas prices, we have voluntarily shut-in certain production, and a prolonged period of decreased prices may result in further curtailments or shutting-in of production, 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, such impact may be adverse and could result, among other things, in PP&E, goodwill or deferred tax asset impairment, or exceeding our debt covenants. See disclosure under "Impairment", “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.

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 crude oil and natural gas assets. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Oil and natural gas sales	$ 285.6	$ 356.4
Less:		
Royalties	(57.5)	(68.9)
Production taxes	(15.4)	(14.6)
Cash operating expenses	(79.0)	(69.8)
Transportation costs	(35.3)	(31.3)
Netback before hedging	$ 98.4	$ 171.8
Cash gains/(losses) on derivative instruments	33.0	10.5
Netback after hedging	$ 131.4	$ 182.3

"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	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Cash flow from operating activities	$ 122.7	$ 109.0
Asset retirement obligation expenditures	10.8	5.4
Changes in non-cash operating working capital	(20.3)	54.4
Adjusted funds flow	$ 113.2	$ 168.8

"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	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Adjusted funds flow	$ 113.2	$ 168.8
Capital spending	(163.6)	(160.8)
Free cash flow	$ (50.4)	$ 8.0

"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, unrealized foreign exchange gain/loss, the tax effect of these items as well as the valuation allowance on our deferred income tax assets.

Calculation of Adjusted Net Income	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Net income/(loss)	$ 2.9	$ 19.2
Unrealized derivative instrument (gain)/loss	(96.4)	95.3
Unrealized foreign exchange (gain)/loss	(2.4)	(17.1)
Tax effect on above items	23.4	(24.9)
Valuation allowance on deferred income tax assets	93.6	—
Adjusted net income	$ 21.1	$ 72.5

"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, 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 adjusted payout ratio as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Dividends	$ 6.7	$ 7.2
Capital, office expenditures and line fill	165.5	167.0
Sub-total	$ 172.2	$ 174.2
Adjusted funds flow	$ 113.2	$ 168.8
Adjusted payout ratio (%)	152%	103%

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

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**March 31, 2020**
Net income/(loss)	$ (276.0)
Add:	
Goodwill impairment	451.1
Interest	34.4
Current and deferred tax expense/(recovery)	180.6
DD&A and asset impairment	376.1
Other non-cash charges(2)	(106.8)
Adjusted EBITDA	$ 659.4

(1) Balances above at March 31, 2020 include the three months ended March 31, 2020 and the second, third and fourth quarter of 2019.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense and unrealized foreign exchange gains/losses.

In addition, the Company uses certain financial measures within the "Liquidity and Capital Resources" section 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", "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

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a - 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at March 31, 2020, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2020 and ended March 31, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form ("AIF"), 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: expected capital spending levels in 2020 and impact thereof on our production levels and land holdings; expected production volumes; expected operating strategy in 2020, including the proportion of Enerplus' production that may be curtailed and the effect of such curtailment on its properties, operations and financial position; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials, our commodity risk management program in 2020 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating costs; our anticipated shares repurchases under future normal course issuer bids; potential future asset and goodwill 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; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes; expectations regarding repayment of our outstanding senior notes, including sources of funds therefor; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2020; and the amount of future cash dividends that we may pay to our shareholders.

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; that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment 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; our ability to comply with our debt covenants; the availability of third party services; and the extent of our liabilities. In addition, our expected 2020 capital expenditures and operating strategy described in this MD&A is based on the rest of the year prices and exchange rate of: a WTI price of US$22.80/bbl, a NYMEX price of US$2.23/Mcf, and a USD/CDN exchange rate of 1.40. 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. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

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 instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further decline and/or 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; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in this MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2019).

The forward-looking information contained in this MD&A speak only as of the date of this MD&A. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2020	December 31, 2019
Assets			
Current Assets			
Cash and cash equivalents		$ 142,076	$ 151,649
Accounts receivable	4	123,527	176,119
Income tax receivable	14	15,085	27,770
Derivative financial assets	16	108,389	10,570
Other current assets		3,397	2,990
		392,474	369,098
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,743,436	1,547,362
Other capital assets, net	5	19,000	20,244
Property, plant and equipment		1,762,436	1,567,606
Right-of-use assets	10	46,582	48,729
Goodwill		210,026	194,015
Deferred income tax asset	14	272,988	372,502
Income tax receivable	14	—	13,852
Total Assets		$ 2,684,506	$ 2,565,802
Liabilities			
Current liabilities			
Accounts payable	7	$ 278,325	$ 291,540
Dividends payable		2,226	2,217
Current portion of long-term debt	8	114,746	105,998
Derivative financial liabilities	16	4,125	2,734
Current portion of lease liabilities	10	17,596	17,541
		417,018	420,030
Long-term debt	8	541,950	500,635
Asset retirement obligation	9	146,074	138,049
Lease liabilities	10	33,760	35,530
		721,784	674,214
Total Liabilities		1,138,802	1,094,244
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: March 31, 2020 – 223 million shares			
December 31, 2019 – 222 million shares	15	3,097,187	3,088,094
Paid-in capital		44,430	59,490
Accumulated deficit		(1,985,964)	(1,984,365)
Accumulated other comprehensive income/(loss)		390,051	308,339
		1,545,704	1,471,558
Total Liabilities & Shareholders' Equity		$ 2,684,506	$ 2,565,802
Commitments and Contingencies	17		

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

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

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended March 31, 2020	2019
Revenues			
Oil and natural gas sales, net of royalties	11	$ 228,127	$ 287,452
Commodity derivative instruments gain/(loss)	16	131,341	(84,867)
		359,468	202,585
Expenses			
Operating		79,020	69,793
Transportation		35,329	31,291
Production taxes		15,444	14,615
General and administrative	12	19,185	21,710
Depletion, depreciation and accretion		95,192	75,911
Interest		8,911	8,393
Foreign exchange (gain)/loss	13	(5,637)	(12,026)
Other expense/(income)		(229)	(2,862)
		247,215	206,825
Income/(Loss) before taxes		112,253	(4,240)
Current income tax expense/(recovery)	14	27	(5,530)
Deferred income tax expense/(recovery)	14	109,350	(17,868)
Net Income/(Loss)		$ 2,876	$ 19,158
Other Comprehensive Income/(Loss)			
Unrealized gain/(loss) on foreign currency translation		131,774	(36,356)
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt	3, 16	(50,062)	—
Total Comprehensive Income/(Loss)		$ 84,588	$ (17,198)
Net income/(Loss) per share			
Basic	15	$ 0.01	$ 0.08
Diluted	15	$ 0.01	$ 0.08

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

Condensed Consolidated Statements of Changes in Shareholders' Equity

(CDN$ thousands) unaudited	Three months ended March 31, 2020	2019
Share Capital		
Balance, beginning of period	$ 3,088,094	$ 3,337,608
Purchase of common shares under Normal Course Issuer Bid	(4,731)	(24,159)
Share-based compensation – treasury settled	13,824	4,406
Balance, end of period	$ 3,097,187	$ 3,317,855
Paid-in Capital		
Balance, beginning of period	$ 59,490	$ 46,524
Share-based compensation – cash settled (tax withholding)	(7,232)	(4,952)
Share-based compensation – treasury settled	(13,824)	(4,406)
Share-based compensation – non-cash	5,996	8,043
Balance, end of period	$ 44,430	$ 45,209
Accumulated Deficit		
Balance, beginning of period	$ (1,984,365)	$ (1,772,084)
Purchase of common shares under Normal Course Issuer Bid	2,195	4,331
Net income/(loss)	2,876	19,158
Dividends declared ($0.01 per share)	(6,670)	(7,162)
Balance, end of period	$ (1,985,964)	$ (1,755,757)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of period	$ 308,339	$ 388,941
Unrealized gain/(loss) on foreign currency translation	131,774	(36,356)
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt	(50,062)	—
Balance, end of period	$ 390,051	$ 352,585
Total Shareholders' Equity	$ 1,545,704	$ 1,959,892

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended March 31, 2020	2019
Operating Activities			
Net income/(loss)		$ 2,876	$ 19,158
Non-cash items add/(deduct):			
Depletion, depreciation and accretion		95,192	75,911
Changes in fair value of derivative instruments	16	(96,428)	95,328
Deferred income tax expense/(recovery)	14	109,350	(17,868)
Foreign exchange (gain)/loss on debt and working capital	13, 16	(2,415)	(17,104)
Share-based compensation and general and administrative	12,15	7,755	8,134
Translation of U.S. dollar cash held in Canada	13	(3,103)	5,196
Asset retirement obligation expenditures	9	(10,794)	(5,390)
Changes in non-cash operating working capital	18	20,306	(54,414)
Cash flow from/(used in) operating activities		122,739	108,951
Financing Activities			
Purchase of common shares under Normal Course Issuer Bid	15	(2,536)	(19,828)
Share-based compensation – cash settled (tax withholding)	15	(7,232)	(4,952)
Dividends	15,18	(6,661)	(7,174)
Cash flow from/(used in) financing activities		(16,429)	(31,954)
Investing Activities			
Capital and office expenditures	18	(129,342)	(111,795)
Property and land acquisitions		(2,256)	(2,981)
Property divestments		5,578	422
Cash flow from/(used in) investing activities		(126,020)	(114,354)
Effect of exchange rate changes on cash and cash equivalents		10,137	(6,974)
Change in cash and cash equivalents		(9,573)	(44,331)
Cash and cash equivalents, beginning of period		151,649	363,327
Cash and cash equivalents, end of period		$ 142,076	$ 318,996

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

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim 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) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three months ended March 31, 2020 and the 2019 comparative periods. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' annual audited Consolidated Financial Statements as of December 31, 2019.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

i. 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: 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. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions.

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. 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 March 31, 2020; however, estimates made during this period of extreme volatility are subject to a higher level of uncertainty and as a result, there may be a further prospective material impact in future periods.

3) ACCOUNTING POLICY CHANGES

Recently adopted accounting standards

a) Hedge Accounting

Effective January 1, 2020, the Company adopted hedge accounting in order to mitigate the foreign currency exposure related to its net investment in its U.S. subsidiary. The Company may designate 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. To be accounted for as a hedge, the U.S. dollar denominated debt must be designated 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.

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).

b) Impairment of Financial Instruments

Enerplus adopted *ASC 326 – Financial Instruments – Credit Losses* effective January 1, 2020 using the modified retrospective method, with the cumulative effect on comparative periods reflected as an adjustment to retained earnings, if applicable. The adoption of the standard had no impact on the interim Consolidated Financial Statements, with the exception of the revised disclosures which are detailed in Note 16. As a result of this adoption, Enerplus has revised its accounting policy for financial instruments as follows:

The Company has adopted 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.

c) Goodwill

Enerplus adopted ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)* effective January 1, 2020 using the prospective method. The amended standard simplifies the goodwill impairment test. As a result of this adoption, Enerplus has revised its accounting policy for goodwill as follows:

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.

4) ACCOUNTS RECEIVABLE

($ thousands)		March 31, 2020		December 31, 2019
Accrued revenue	$	96,436	$	142,048
Accounts receivable – trade		30,853		37,736
Allowance for doubtful accounts		(3,762)		(3,665)
Total accounts receivable, net of allowance for doubtful accounts	$	123,527	$	176,119

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

As of March 31, 2020 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Oil and natural gas properties(1)	$	15,864,102	$	(14,120,666)	$	1,743,436
Other capital assets		126,151		(107,151)		19,000
Total PP&E	$	15,990,253	$	(14,227,817)	$	1,762,436

As of December 31, 2019 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
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.

6) IMPAIRMENT

a) Impairment of PP&E

There was no impairment recorded for the three months ended March 31, 2020 and 2019. Enerplus expects the twelve month trailing prices to decline further in 2020, impacting the ceiling value and increasing the risk of future PP&E impairment.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2019 through March 31, 2020:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q1 2020	$ 55.96	$ 66.42	$ 2.30	1.33
Q4 2019	55.85	66.73	2.58	1.33
Q3 2019	57.77	62.79	2.83	1.33
Q2 2019	61.38	66.07	3.02	1.32
Q1 2019	63.00	67.30	3.07	1.32

b) Impairment of Goodwill

At March 31, 2020, Enerplus identified indicators of goodwill impairment in the form of deteriorating macroeconomic conditions both in relation to the COVID-19 pandemic and a decline in commodity prices. Enerplus performed a quantitative test that utilized the discounted after-tax cash flows associated with the proved and probable reserves at forecast prices and costs of the U.S. reporting unit. As a result of this assessment, the Company concluded that the carrying value of the reporting unit did not exceed its fair value. There was no goodwill impairment for the three months ended March 31, 2020 (December 31, 2019 - $451.1 million for the Canadian reporting unit). There is a risk of future goodwill impairment if forecast commodity prices continue to weaken, there is a downward revision to reserves, or additional adverse changes reduce the underlying cash flows used to estimate the fair value of the reporting unit. At March 31, 2020, goodwill consisted of $210.0 million related to Enerplus' U.S. reporting unit.

7) ACCOUNTS PAYABLE

($ thousands)	March 31, 2020	December 31, 2019
Accrued payables	$ 129,809	$ 105,928
Accounts payable – trade	148,516	185,612
Total accounts payable	$ 278,325	$ 291,540

8) DEBT

($ thousands)	March 31, 2020	December 31, 2019
Current:		
Senior notes	$ 114,746	$ 105,998
Long-term:		
Bank credit facility	—	—
Senior notes	541,950	500,635
Total debt	$ 656,696	$ 606,633

The terms and rates of the Company's outstanding senior notes are provided 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	$ 147,651
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	28,124
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	419,048
June 18, 2009	June 18 and Dec 18	2 equal annual installments on June 18, 2020 and 2021	7.97%	US$225,000	US$44,000	61,873
					Total carrying value	$ 656,696

9) ASSET RETIREMENT OBLIGATION

($ thousands)	March 31, 2020	December 31, 2019
Balance, beginning of year	$ 138,049	$ 126,112
Change in estimates	15,326	23,362
Property acquisitions and development activity	1,838	2,068
Divestments	(47)	(2,760)
Settlements	(10,794)	(16,715)
Accretion expense	1,702	5,982
Balance, end of period	$ 146,074	$ 138,049

Enerplus has estimated the present value of its asset retirement obligation to be $146.1 million at March 31, 2020 based on a total undiscounted liability of $359.3 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% (December 31, 2019 – 5.50%).

10) 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)	March 31, 2020	December 31, 2019
Assets		
Operating right-of-use assets	$ 46,582	$ 48,729
Liabilities		
Current operating lease liabilities	$ 17,596	$ 17,541
Non-current operating lease liabilities	33,760	35,530
Total lease liabilities	$ 51,356	$ 53,071
Weighted average remaining lease term (years)		
Operating leases	4.1	4.3
Weighted average discount rate		
Operating leases	4.1%	4.1%

The components of lease expense for the three months ended March 31, 2020 are as follows:

	Three months ended March 31,	
($ thousands)	2020	2019
Operating lease cost	$ 5,132	$ 4,593
Variable lease cost	317	285
Short-term lease cost	5,285	4,121
Sublease income	(293)	(244)
Total	$ 10,441	$ 8,755

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

($ thousands)		Operating Leases
2020	$	15,542
2021		14,938
2022		7,996
2023		6,897
2024		6,304
After 2025		4,308
Total lease payments	$	55,985
Less imputed interest		(4,629)
Total discounted lease payments	$	51,356
Current portion of lease liabilities	$	17,596
Non-current portion of lease liabilities	$	33,760

Supplemental information related to leases is as follows:

	Three months ended March 31,			
($ thousands)		2020		2019
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$	4,929	$	4,506
Right-of-use assets obtained in exchange for lease obligations:				
Operating leases	$	523	$	18,863

11) OIL AND NATURAL GAS SALES

	Three months ended March 31,			
($ thousands)		2020		2019
Oil and natural gas sales	$	285,598	$	356,376
Royalties[1]		(57,471)		(68,924)
Oil and natural gas sales, net of royalties	$	228,127	$	287,452

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

Oil and natural gas revenue by country and by product for the three months ended March 31, 2020 and 2019 are as follows:

Three months ended March 31, 2020 ($ thousands)		Total revenue, net of royalties[1]		Crude oil[2]		Natural gas[2]		Natural gas liquids[2]		Other[3]
Canada	$	27,091	$	21,989	$	3,388	$	1,094	$	620
United States		201,036		159,765		37,466		3,750		55
Total	$	228,127	$	181,754	$	40,854	$	4,844	$	675

Three months ended March 31, 2019 ($ thousands)		Total revenue, net of royalties[1]		Crude oil[2]		Natural gas[2]		Natural gas liquids[2]		Other[3]
Canada	$	52,895	$	39,417	$	10,367	$	2,486	$	625
United States		234,557		157,841		73,157		3,559		—
Total	$	287,452	$	197,258	$	83,524	$	6,045	$	625

(1) Royalties above do not include production taxes which are reported separately on the Condensed 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.

12) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended March 31,			
($ thousands)		2020		2019
General and administrative expense	$	12,335	$	12,431
Share-based compensation expense		6,850		9,279
General and administrative expense[1]	$	19,185	$	21,710

(1) Includes cash and non-cash amounts.

13) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31, 2020	2019
Realized:		
Foreign exchange (gain)/loss	$ (119)	$ (118)
Translation of U.S. dollar cash held in Canada (gain)/loss	(3,103)	5,196
Unrealized:		
Translation of U.S. dollar debt and working capital (gain)/loss	(2,415)	(17,104)
Foreign exchange (gain)/loss	$ (5,637)	$ (12,026)

Effective January 1, 2020, the Company elected to apply net investment hedge accounting. Any unrealized foreign exchange gain or loss recorded on certain U.S. dollar denominated debt held in Canada after adoption has been reflected in Other Comprehensive Income/(Loss) on the Consolidated Statements of Income/(Loss). See Note 3 for further details.

14) INCOME TAXES

($ thousands)	Three months ended March 31, 2020	2019
Current tax		
United States	$ 27	$ (5,530)
Current tax expense/(recovery)	27	(5,530)
Deferred tax		
Canada	$ 124,481	$ (29,559)
United States	(15,131)	11,691
Deferred tax expense/(recovery)	109,350	(17,868)
Income tax expense/(recovery)	$ 109,377	$ (23,398)

The difference between the expected income taxes based on the statutory income tax rate and the effective income taxes for the current and prior period is impacted by the following: expected annual earnings, recognition or reversal of valuation allowance, foreign rate differentials for foreign operations, statutory and other rate differentials, non-taxable portions of capital gains and losses, and share-based compensation.

Each period, Enerplus assesses the recoverability of its deferred tax assets to determine whether it is more likely than not all or a portion of its deferred tax assets will not be realized. In making that assessment, the Company considers available positive and negative evidence including future taxable income and reversing existing temporary differences. Enerplus has concluded that it is more likely than not that a portion of its Canadian deferred income tax assets will not be realized and has recorded a valuation allowance of $93.6 million for the period ending March 31, 2020 (December 31, 2019 - $13.9 million). No valuation allowance was recorded against the Company's 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 continue to weaken or other evidence indicates that more of the Company’s deferred income tax assets will not be realized. After recording the valuation allowance, the Company’s overall net deferred income tax asset was $273.0 million as at March 31, 2020 (December 31, 2019 - $372.5 million).

At March 31, 2020, $14.9 million of the current income tax receivable related to a portion of the U.S. Alternative Minimum Tax refund (December 31, 2019 - $27.8 million).

15) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	Three months ended March 31, 2020 Shares	Amount	Year ended December 31, 2019 Shares	Amount
Balance, beginning of year	221,744	$ 3,088,094	239,411	$ 3,337,608
Issued/(Purchased) for cash:				
Purchase of common shares under Normal Course Issuer Bid	(340)	(4,731)	(18,231)	(253,920)
Non-cash:				
Share-based compensation – settled(1)	1,160	13,824	564	4,406
Balance, end of period	222,564	$ 3,097,187	221,744	$ 3,088,094

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

Dividends declared to shareholders for the three months ended March 31, 2020 were $6.7 million (2019 – $7.2 million).

Enerplus' Normal Course Issuer Bid ("NCIB") expired on March 25, 2020. The Company chose not to renew the NCIB upon expiry in order to conserve capital and preserve its liquidity; however, Enerplus plans to renew its NCIB in due course and recommence its share repurchase program when market conditions improve. 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.

During the three months ended March 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.

During the three months ended March 31, 2019, the Company repurchased 1,732,038 common shares under the NCIB at an average price of $11.43 per share, for total consideration of $19.8 million. Of the amount paid, $24.1 million was charged to share capital and $4.3 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 Condensed Consolidated Statements of Income/(Loss):

($ thousands)	Three months ended March 31, 2020	2019
Cash:		
Long-term incentive plans (recovery)/expense	$ (2,747)	$ 1,337
Non-cash:		
Long-term incentive plans	7,689	8,043
Equity swap (gain)/loss	1,908	(101)
Share-based compensation expense	$ 6,850	$ 9,279

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

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Deferred Share Unit ("DSU") and RSU Plan activity for the three months ended March 31, 2020:

(thousands of units)	Cash-settled LTI plans Director Plans	Equity-settled LTI plans PSU(1)	RSU	Total
Balance, beginning of year	422	2,139	1,531	4,092
Granted	121	1,131	1,079	2,331
Vested	—	(652)	(741)	(1,393)
Forfeited	—	—	(18)	(18)
Balance, end of period	543	2,618	1,851	5,012

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

Cash-settled LTI Plans

For the three months ended March 31, 2020, the Company recorded a cash share-based compensation recovery of $2.7 million (March 31, 2019 – expense of $1.3 million).

As of March 31, 2020, a liability of $1.1 million (December 31, 2019 – $3.9 million) with respect to the Director DSU and RSU plans has been recorded to Accounts Payable on the Condensed 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 Condensed Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At March 31, 2020 ($ thousands, except for years)		PSU(1)		RSU		Total
Cumulative recognized share-based compensation expense	$	18,268	$	7,595	$	25,863
Unrecognized share-based compensation expense		17,206		12,133		29,339
Fair value	$	35,474	$	19,728	$	55,202
Weighted-average remaining contractual term (years)		2.1		1.8		

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three months ended March 31, 2020, $7.2 million (2019 – $5.0 million) in cash withholding taxes were paid.

ii) Stock Option Plan

At March 31, 2020 all stock options are fully vested and any related 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 three months ended March 31, 2020:

	Number of Options (thousands)		Weighted Average Exercise Price
Options outstanding, beginning of year	2,107	$	14.24
Forfeited	(8)		14.85
Expired	(2,099)		14.24
Options outstanding, end of period	—	$	—

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

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

	Three months ended March 31,			
(thousands, except per share amounts)		2020		2019
Net income/(loss)	$	2,876	$	19,158
Weighted average shares outstanding – Basic		222,357		238,922
Dilutive impact of share-based compensation		943		2,376
Weighted average shares outstanding – Diluted		223,300		241,298
Net income/(loss) per share				
Basic	$	0.01	$	0.08
Diluted	$	0.01	$	0.08

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At March 31, 2020, the carrying value of cash, accounts receivable, accounts payable, and dividends payable approximated their fair value due to the short-term maturity of the instruments.

At March 31, 2020, the senior notes had a carrying value of $656.7 million and a fair value of $651.0 million (December 31, 2019 – $606.6 million and $613.8 million, respectively).

The fair value of derivative contracts and senior notes are considered level 2 fair value measurements. There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three months ended March 31, 2020 and 2019:

Gain/(Loss) ($ thousands)	Three months ended March 31, 2020	Three months ended March 31, 2019	Income Statement Presentation
Equity Swaps	$ (1,908)	$ 101	G&A expense
Commodity Derivative Instruments:			
Oil	98,336	(86,929)	Commodity derivative instruments
Gas	—	(8,500)	
Total	$ 96,428	$ (95,328)	

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

($ thousands)	Three months ended March 31, 2020	Three months ended March 31, 2019
Change in fair value gain/(loss)	$ 98,336	$ (95,429)
Net realized cash gain/(loss)	33,005	10,562
Commodity derivative instruments gain/(loss)	$ 131,341	$ (84,867)

The following table summarizes the fair values of derivative financial instruments at the respective period ends:

	March 31, 2020		December 31, 2019	
	Assets	Liabilities	Assets	Liabilities
($ thousands)	Current	Current	Current	Current
Equity Swaps	$ —	$ 4,125	$ —	$ 2,217
Commodity Derivative Instruments:				
Oil	108,389	—	10,570	517
Total	$ 108,389	$ 4,125	$ 10,570	$ 2,734

c) Risk Management

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 derivatives 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 the Company's price risk management positions at May 7, 2020:

Crude Oil Instruments:

Instrument Type[(1)(2)]	**bbls/day**	**US$/bbl**
Apr 1, 2020 – Jun 30, 2020		
WTI Swap	9,500	57.37
WTI Purchased Put	16,000	57.50
WTI Sold Put	16,000	46.88
WTI – Brent Swap (Purchase)	4,400	(8.03)
WTI – Brent Swap (Sale)	4,400	(3.98)

Jul 1, 2020 – Sep 30, 2020		
WTI Swap	7,000	36.02
WTI Purchased Put	21,000	57.20
WTI Sold Put	21,000	47.14
WTI Sold Call	5,000	65.00
WTI – Brent Swap (Purchase)	4,400	(8.03)
Oct 1, 2020 – Dec 31, 2020		
WTI Purchased Put	21,000	57.20
WTI Sold Put	21,000	47.14
WTI Sold Call	5,000	65.00
WTI – Brent Swap (Purchase)	4,400	(8.03)

(1) Transactions with a common term have been aggregated and presented at a weighted average price/bbl before premiums.
(2) The total average deferred premium on outstanding hedges is US$1.67/bbl from April 1, 2020 to December 31, 2020.

Enerplus has fixed physical differential sales agreements for approximately 13,000 bbls/day in North Dakota at an estimated price of WTI less US$5.00/bbl for the remainder of 2020.

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 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 March 31, 2020, Enerplus did not have any foreign exchange derivatives outstanding.

Enerplus may designate 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. 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. At March 31, 2020, Enerplus designated all of its US$467 million senior notes as a hedge of the Company's net investment in its U.S. subsidiary. For the three months ended March 31, 2020, Enerplus recorded a $50.1 million loss, net of tax of nil, on its net investment hedge.

Interest Rate Risk:

At March 31, 2020, all of Enerplus' debt was based on fixed interest rates and Enerplus had no 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 15. Enerplus has entered into various equity swaps maturing in 2020 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 has appropriate policies and procedures in place to manage its credit risk; however, given the recent rapid decline in commodity prices, Enerplus is subject to an increased risk of financial loss due to non-performance or insolvency of its counterparties.

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 March 31, 2020, approximately 80% 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 of future payments or seeking other remedies including legal action. Enerplus' allowance for doubtful accounts balance at March 31, 2020 was $3.8 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 share capital. Enerplus' objective is to provide adequate short and long 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, and acquisition and divestment activity.

At March 31, 2020, Enerplus had $142.1 million in cash and cash equivalents and an undrawn US$600 million bank credit facility. The Company was in full compliance with all covenants under the bank credit facility and outstanding senior notes. Enerplus expects to manage its business within these financial ratios during 2020; however, current oil and gas prices have created a significant level of uncertainty which may challenge this expectation. If the Company exceeds or anticipates exceeding its covenants, the Company may be required to repay, refinance or renegotiate the terms of the debt.

17) COMMITMENTS AND CONTINGENCIES

As of the date of this report, there were no material changes to Enerplus' contractual obligations and commitments outside the ordinary course of business as reported in the Company's annual audited Consolidated Financial Statements as of December 31, 2019.

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.

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended March 31,	
($ thousands)	2020	2019
Accounts receivable	$ 80,816	$ (14,179)
Other assets	(407)	(3,027)
Accounts payable	(60,103)	(37,208)
	$ 20,306	$ (54,414)

b) Changes in Other Non-Cash Working Capital

	Three months ended March 31,	
($ thousands)	2020	2019
Non-cash financing activities(1)	$ 9	$ (12)
Non-cash investing activities(2)	36,195	50,101

(1) Relates to changes in dividends payable and included in dividends on the Condensed 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 Condensed Consolidated Statements of Cash Flows.

c) Other

	Three months ended March 31,	
($ thousands)	2020	2019
Income taxes paid/(received)	$ (30,167)	$ 64
Interest paid	3,287	3,259

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

Michael R. Culbert[(3)(5)(10)]
Corporate Director
Calgary, Alberta

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)(9)(11)]
Corporate Director
Calgary, Alberta

Elliott Pew
Corporate Director
Calgary, Alberta

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, U.S. Operations and Engineering

Nathan D. Fisher
Vice President, U.S. Development & Geosciences

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Canadian Operations

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Edward L. McLaughlin
President, U.S. Operations

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

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Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

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New York Stock Exchange: ERF

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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	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
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 at Edmonton, Alberta, the benchmark for Canadian light sweet crude oil pricing
NCIB	Normal Course Issuer Bid
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
SBC	share based compensation
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
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

enerPLUS

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