enerPLUS

Second Quarter Report

Six Months Ended June 30, 2019

SELECTED FINANCIAL RESULTS	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Financial (000's)				
Net Income	$ 85,084	$ 12,404	$ 104,242	$ 42,041
Cash Flow from Operating Activities	236,991	141,767	345,942	301,067
Adjusted Funds Flow[4]	186,038	173,708	354,793	328,870
Dividends to Shareholders - Declared	7,034	7,347	14,196	14,667
Total Debt Net of Cash[4]	359,006	311,782	359,006	311,782
Capital Spending	207,208	177,082	368,001	328,554
Property and Land Acquisitions	1,911	2,392	4,936	14,664
Property Divestments	9,601	(182)	10,067	6,788
Net Debt to Adjusted Funds Flow Ratio[4]	0.5x	0.5x	0.5x	0.5x
Financial per Weighted Average Shares Outstanding				
Net Income - Basic	$ 0.36	$ 0.05	$ 0.44	$ 0.17
Net Income - Diluted	0.36	0.05	0.43	0.17
Weighted Average Number of Shares Outstanding (000's) - Basic	235,490	244,862	237,197	244,369
Weighted Average Number of Shares Outstanding (000's) - Diluted	238,189	250,122	239,947	249,367
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 44.00	$ 48.13	$ 44.33	$ 45.65
Royalties and Production Taxes	(11.26)	(12.08)	(10.90)	(11.28)
Commodity Derivative Instruments	(0.13)	(2.28)	0.55	(0.57)
Cash Operating Expenses	(7.84)	(7.21)	(8.26)	(7.12)
Transportation Costs	(4.02)	(3.56)	(3.97)	(3.54)
Cash General and Administrative Expenses	(1.26)	(1.44)	(1.39)	(1.57)
Cash Share-Based Compensation	0.07	(0.05)	(0.04)	(0.16)
Interest, Foreign Exchange and Other Expenses	(0.79)	(0.95)	(0.75)	(0.99)
Current Income Tax Recovery/(Expense)	1.52	(0.01)	1.14	(0.01)
Adjusted Funds Flow[4]	$ 20.29	$ 20.55	$ 20.71	$ 20.41

SELECTED OPERATING RESULTS	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Average Daily Production[2]				
Crude Oil (bbls/day)	48,141	45,242	44,642	41,364
Natural Gas Liquids (bbls/day)	4,720	4,808	4,552	4,449
Natural Gas (Mcf/day)	287,000	256,995	272,863	259,141
Total (BOE/day)	100,694	92,883	94,671	89,003
% Crude Oil and Natural Gas Liquids	52%	54%	52%	51%
Average Selling Price [2][3]				
Crude Oil (per bbl)	$ 74.42	$ 79.98	$ 70.82	$ 75.34
Natural Gas Liquids (per bbl)	17.96	32.23	18.53	30.36
Natural Gas (per Mcf)	2.63	2.68	3.46	3.09
Net Wells Drilled	13	18	30	32

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(3) Before transportation costs, royalties and the effects of commodity derivative instruments.
(4) 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.

Average Benchmark Pricing	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
WTI crude oil (US$/bbl)	$ 59.81	$ 67.88	$ 57.36	$ 65.37
Brent (ICE) crude oil (US$/bbl)	68.32	74.90	66.11	71.04
NYMEX natural gas – last day (US$/Mcf)	2.64	2.80	2.89	2.90
USD/CDN average exchange rate	1.34	1.29	1.33	1.28

Share Trading Summary For the three months ended June 30, 2019	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 13.10	$ 9.74
Low	$ 8.76	$ 6.53
Close	$ 9.85	$ 7.53

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

2019 Dividends per Share	CDN$	US$[1]
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Total	$ 0.06	$ 0.04

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

NEWS RELEASE

Highlights:

- Second quarter total production was 100,694 BOE per day, up 14% quarter-over-quarter, exceeding the high-end of the Company's guidance
  - Liquids production was 52,861 barrels per day, up 16% quarter-over-quarter
  - North Dakota production was 43,822 BOE per day, up 22% quarter-over-quarter
- 2019 total production guidance increased to 99,000 to 102,000 BOE per day (from 97,000 to 101,000 BOE per day) and liquids production guidance narrowed to 54,000 to 55,500 barrels per day (from 53,500 to 56,000 barrels per day)
  - 14% liquids production per share growth in 2019 at the guidance midpoint
- 2019 capital spending guidance tightened to $610 to $630 million (from $590 to $630 million)
- Returned approximately $115 million of capital to shareholders through dividends and share repurchases year to date
- Based on current market conditions, Enerplus intends to repurchase its full authorization under its normal course issuer bid ("NCIB") equaling an additional 8.9 million shares as at August 7, 2019. Once completed, this would equate to a total of 24.2 million shares repurchased, or approximately 10% of shares outstanding, since initiating the share repurchase program in the third quarter of 2018
- Improved 2019 Bakken oil differential guidance to US$3.25 per barrel below WTI (from US$4.00 per barrel)
- Reduced 2019 unit cost guidance for operating expenses and cash general & administrative ("G&A") expenses
- Maintained significant financial flexibility; total debt net of cash was $359.0 million with a net debt to adjusted funds flow ratio of 0.5 times

President and Chief Executive Officer Ian C. Dundas commented: "We've established strong operational momentum through the first half of the year and remain well positioned relative to our financial and operational targets in 2019. Our strategy continues to be underpinned by disciplined capital allocation which is delivering profitable oil production growth and return of capital to shareholders, while maintaining our peer-leading balance sheet strength."

"Since initiating our share repurchase program in the third quarter of 2018, we've returned over $175 million to shareholders through repurchases. Underlying this decision has been the compelling value we see in our equity. We continue to see this value in our shares today and remain committed to prioritizing the acquisition of our stock, based on current market conditions."

Second Quarter Financial and Operational Summary

PRODUCTION

Production in the second quarter increased by 14% from the prior quarter to average 100,694 BOE per day, including oil and natural gas liquids production of 52,861 barrels per day (91% oil). The sequential production increase was driven by North Dakota and Marcellus volumes which were up 22% and 14%, respectively. With outperformance in the Marcellus and continued strong production in North Dakota, Enerplus is increasing its annual production guidance to 99,000 to 102,000 BOE per day (from 97,000 to 101,000 BOE per day) and narrowing its liquids production guidance to 54,000 to 55,500 barrels per day (from 53,500 to 56,000 barrels per day).

North Dakota production is expected to meaningfully build in the third quarter due to the timing of several well completions late in the second quarter and continued completions activity in the third quarter, with volumes moderating into the fourth quarter.

During the second quarter, Enerplus closed divestments for proceeds of $9.6 million primarily related to the sale of properties in southeast Saskatchewan with associated production of approximately 350 barrels per day (100% oil).

ADJUSTED FUNDS FLOW AND ADJUSTED NET INCOME

Second quarter 2019 adjusted funds flow was $186.0 million compared to $168.8 million in the previous quarter. Second quarter adjusted funds flow included a current tax recovery of $13.9 million. Second quarter 2019 adjusted net income was $74.3 million ($0.32 per share) compared to $72.5 million ($0.30 per share) in the previous quarter.

PRICING REALIZATION AND COST STRUCTURE

Enerplus' realized Bakken oil price differential averaged US$3.00 per barrel below WTI in the second quarter. Based on year to date price realizations and the continued strength in Bakken differentials, Enerplus is revising its full year Bakken differential guidance to US$3.25 per barrel below WTI (from US$4.00 per barrel). The Company continues to manage differential risk through fixed physical sales. For the second half of 2019, Enerplus has fixed physical differential sales of approximately 26,300 barrels per day of Bakken oil production at US$2.66 per barrel below WTI, including a portion which is sold directly into the U.S. Gulf Coast that utilizes the Company's firm capacity on the Dakota Access Pipeline. Enerplus' remaining production is sold through a combination of in-basin monthly spot and index sales.

The Company's realized Marcellus natural gas price differential moderated in the second quarter to US$0.57 per Mcf below NYMEX from the strong pricing in the prior quarter. A significant portion of the Company's Marcellus sales are tied to the Transco Zone 6 non-New York markets, where seasonal changes in demand drive prices lower from winter to spring. Enerplus is widening its full-year 2019 Marcellus differential guidance to US$0.35 per Mcf below NYMEX (from US$0.30 per Mcf).

Second quarter operating expenses were $7.84 per BOE, transportation expenses were $4.02 per BOE and cash G&A expenses were $1.26 per BOE. Enerplus is reducing its 2019 operating expense guidance to $7.90 per BOE (from $8.00 per BOE) and its cash G&A guidance to $1.45 per BOE (from $1.50 per BOE) primarily due to the Company's higher 2019 production expectations.

CAPITAL EXPENDITURES AND BALANCE SHEET POSITION

Exploration and development capital spending in the second quarter was $207.2 million and was associated with drilling 12.7 net wells and bringing 26.3 net wells on production across the Company's operations. Enerplus has narrowed its 2019 capital spending guidance to $610 to $630 million (from $590 to $630 million) following the continued optimization of its operational plans. Capital spending for the second half of 2019 is expected to be weighted to the third quarter.

The Company continues to maintain its significant financial flexibility. At the end of the second quarter, its total debt net of cash was $359.0 million and its net debt to adjusted funds flow ratio was 0.5 times.

SHARE REPURCHASE

The Company repurchased and cancelled 6.6 million shares during the second quarter for total consideration of $70.6 million. Since initiating its share repurchase program in the third quarter of 2018 up to and including August 7, 2019, the Company has repurchased and cancelled 15.3 million shares for total consideration of $178 million.

Enerplus continues to see the current trading value of its equity as discounted relative to the Company's internal view. As a result, the Company intends to repurchase the remaining authorization under its NCIB equaling an additional 8.9 million shares as at August 7, 2019. Combined with the shares repurchased to date, this would represent a total of 24.2 million shares repurchased, or approximately 10% of shares outstanding, since initiating its share repurchase program in the third quarter of 2018. The Company's existing NCIB expires March 25, 2020.

ASSET ACTIVITY

Average Daily Production(1)

	Three months ended June 30, 2019				Six months ended June 30, 2019			
	Crude Oil (Mbbl/d)	**NGL** (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)	**Crude Oil** (Mbbl/d)	**NGL** (Mbbl/d)	**Natural Gas** (MMcf/d)	**Total** (Mboe/d)
Williston Basin	38.8	3.7	26.6	46.9	35.1	3.5	25.9	42.9
Marcellus	—	—	237.3	39.5	—	—	223.2	37.2
Canadian Waterfloods	8.4	0.1	3.9	9.2	8.6	0.1	3.5	9.3
Other(2)	0.9	0.9	19.2	5.0	1.0	0.9	20.2	5.2
Total	**48.1**	**4.7**	**287.0**	**100.7**	**44.6**	**4.6**	**272.9**	**94.7**

(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 June 30, 2019				Six months ended June 30, 2019			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	26.0	23.3	3.0	1.4	29.0	26.3	4.0	1.9
Marcellus	—	—	14.0	1.6	—	—	27.0	3.5
Canadian Waterfloods	—	—	—	—	1.0	1.0	—	—
Other[(2)]	—	—	—	—	—	—	2.0	0.5
Total	**26.0**	**23.3**	**17.0**	**3.0**	**30.0**	**27.3**	**33.0**	**5.8**

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

WILLISTON BASIN

Williston Basin production averaged 46,920 BOE per day (83% oil) during the second quarter of 2019, including 43,822 BOE per day from North Dakota (83% oil). The Company drilled 11 gross operated wells (73% average working interest) and brought 26 gross operated wells (90% average working interest) on production during the second quarter, including a nine-well pad at the end of June.

Enerplus continues to drive capital efficiency improvements with current well costs down approximately US$700,000 from 2018 levels driven by a combination of lower costs, efficiencies and completion optimization. Enerplus' current total well cost for a two-mile lateral (drill, complete, tie-in and facilities) is estimated at US$7.5 million.

MARCELLUS

Marcellus production averaged 237 MMcf per day during the second quarter, 14% higher than the previous quarter. The Company participated in drilling eight gross non-operated wells (4% average working interest) and brought 14 gross non-operated wells (11% average working interest) on production during the quarter.

DJ BASIN

The Company drilled five gross operated wells (88% average working interest) in the second quarter. These wells are expected to be completed in the third quarter.

2019 Guidance Updates

The Company's updated guidance for 2019 is in the table below, including changes from its previous guidance.

	Guidance
Capital spending	$610 to $630 million (from $590 to $630 million)
Average annual production	99,000 to 102,000 BOE/day (from 97,000 to 101,000 BOE/day)
Average annual crude oil and natural gas liquids production	54,000 to 55,500 bbls/day (from 53,500 to 56,000 bbls/d)
Average royalty and production tax rate	25%
Operating expense	$7.90/BOE (from $8.00/BOE)
Transportation expense	$4.00/BOE
Cash G&A expense	$1.45/BOE (from $1.50/BOE)

2019 Full-Year Differential/Basis Outlook[(1)]	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.25)/bbl (from US$(4.00)/bbl)
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.35)/Mcf (from US$(0.30)/Mcf)

(1) Excluding transportation costs.

Risk Management

Enerplus continues to manage price risk through commodity hedging. Enerplus has an average of 24,500 barrels per day of crude oil protected for the remainder of 2019 and 16,000 barrels per day protected in 2020.

For natural gas, Enerplus has entered into offsetting swaps through October 31, 2019, effectively locking in gains of $0.51 per Mcf on the Company's original NYMEX hedges through this term.

Commodity Hedging Detail (As at August 7, 2019)

	WTI Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)	
	Jul 1, 2019 – Sep 30, 2019	Oct 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020	Jul 1, 2019 – Jul 31, 2019	Aug 1, 2019 – Oct 31, 2019
Swaps					
Sold Swaps	—	—	—	$ 2.85	$ 2.85
Volume (bbls/d or Mcf/d)	—	—	—	90,000	90,000
Purchased Swaps	—	—	—	$ 2.34	$ 2.34
Volume (bbls/d or Mcf/d)	—	—	—	60,000	90,000
Three Way Collars					
Sold Puts	$ 44.64	$ 44.64	—	—	—
Volume (bbls/d or Mcf/d)	24,500	24,500	—	—	—
Purchased Puts	$ 54.81	$ 54.81	—	—	—
Volume (bbls/d or Mcf/d)	24,500	24,500	—	—	—
Sold Calls	$ 65.95	$ 65.99	—	—	—
Volume (bbls/d or Mcf/d)	24,500	24,500	—	—	—
Put Spreads					
Sold Puts	—	—	$ 46.88	—	—
Volume (bbls/d or Mcf/d)	—	—	16,000	—	—
Purchased Puts	—	—	$ 57.50	—	—
Volume (bbls/d or Mcf/d)	—	—	16,000	—	—

(1) The total average deferred premium on outstanding hedges is US$2.00/bbl from July 1, 2019 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 industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. To continue to be comparable with its Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis. All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest.

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 2019 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2019 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; expected operating and transportation costs; our anticipated shares repurchases under current and future normal course issuer bids; capital spending levels in 2019 and impact thereof on our production levels and land holdings; 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; 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; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; 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 will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our updated 2019 guidance contained in this news release is based on the rest of the year prices of: a WTI price of US$56.00/bbl, a NYMEX price of US$2.30/Mcf, and a USD/CDN exchange rate of 1.31. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct

The forward-looking information included in this 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 low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2018).

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

NON-GAAP MEASURES

In this news release, we use the terms "adjusted funds flow", "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. "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", "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' Second Quarter 2019 MD&A.

Electronic copies of Enerplus Corporation's Second Quarter 2019 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 August 8, 2019 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 and six months ended June 30, 2019 and 2018 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016; and
- our MD&A for the year ended December 31, 2018 (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.

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, utilizing a conversion on a 6:1 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 are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. 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.

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.

Effective in 2019, Enerplus adopted ASC 842 - Leases. The most significant impact was the recognition of right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for operating leases and additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Production for the second quarter averaged 100,694 BOE/day, an increase of 14% compared to the first quarter of 2019 and exceeded our second quarter guidance of 97,500 to 100,000 BOE/day. Our crude oil and natural gas liquids production increased by 16% to 52,861 bbls/day from 45,488 bbls/day in the first quarter of 2019, meeting the high end of our second quarter crude oil and natural gas liquids production guidance range of 51,500 to 53,000 bbls/day. The increase in our liquids production was primarily due to our 24.7 net wells brought on-stream during the period in North Dakota. Our natural gas production increased by 11% or 28,432 Mcf/day from the first quarter of 2019 to 287,000 Mcf/day due to outperformance in our Marcellus properties. As a result of higher production in the Marcellus, we are increasing our average annual production guidance range to 99,000 to 102,000 BOE/day (from 97,000 to 101,000 BOE/day). We are also narrowing our average annual crude oil and natural gas liquids guidance to 54,000 to 55,500 bbls/day (from 53,500 to 56,000 bbls/day).

Capital expenditures during the second quarter of $207.2 million were in line with our expectations, with approximately 80% of our capital spending directed to our North Dakota crude oil properties. We are narrowing our 2019 annual capital spending guidance range to $610 – $630 million from $590 – $630 million.

Operating expenses for the quarter were $71.8 million or $7.84/BOE compared to $69.8 million or $8.75/BOE in the first quarter of 2019. The decrease on a per BOE basis was mainly due to increased production in the second quarter of 2019. We are reducing our annual operating cost guidance of $8.00/BOE to $7.90/BOE for 2019, due to the increase in our average annual production guidance.

Cash G&A expenses for the second quarter were $11.5 million or $1.26/BOE, a decrease of 19% on a per BOE basis from $1.55/BOE in the first quarter of 2019. Cash G&A expenses decreased on a per BOE basis, primarily due to higher production volumes during the period. We are reducing our annual guidance of $1.50/BOE to $1.45/BOE for cash G&A expenses for the year.

During the second quarter of 2019, our Bakken crude oil price differential improved to US$3.00/bbl below WTI, compared to US$3.25/bbl below WTI in the first quarter of 2019. Our Marcellus natural gas differential widened to US$0.57/Mcf below NYMEX in the second quarter, compared to US$0.13/Mcf above NYMEX in the first quarter of 2019, due to lower gas prices and a decline in weather-related demand. In addition, our first quarter Marcellus natural gas prices benefited from fixed basis sales at markedly higher levels than the settled benchmarks. We are reducing our full year U.S. Bakken crude oil differential outlook to US$3.25/bbl below WTI from US$4.00/bbl and revising our full year Marcellus natural gas sales price differential outlook to US$0.35/Mcf below NYMEX from US$0.30/Mcf.

As of August 7, 2019, we had approximately 66% of our forecasted crude oil production, net of royalties, hedged for 2019, and approximately 43% of our crude oil production, net of royalties, hedged in 2020, based on 2019 forecasted net production.

We reported net income of $85.1 million in the second quarter of 2019 compared to $19.2 million in the first quarter of 2019. The increase is primarily the result of a $34.0 million increase to revenue, net of royalties, resulting from higher production and a $28.6 million unrealized gain on commodity derivative instruments, compared to an unrealized loss of $95.4 million in the first quarter of 2019.

In the second quarter of 2019, cash flow from operations increased to $237.0 million, compared to $109.0 million in the first quarter of 2019 due to higher production and changes to working capital, most notably, the receipt of the first Alternative Minimum Tax (“AMT”) refund of $57.2 million in the second quarter of 2019. Adjusted funds flow in the second quarter increased to $186.0 million from $168.8 million in the first quarter of 2019, as a result of increased production and a current tax recovery of $13.9 million, compared to $5.5 million in the prior period.

During the quarter, we repurchased and cancelled 6,626,783 common shares under our Normal Course Issuer Bid (“NCIB”) for total consideration of $70.6 million.

At June 30, 2019, our total debt net of cash was $359.0 million and our net debt to adjusted funds flow ratio was 0.5x.

RESULTS OF OPERATIONS

Production

Average daily production for the second quarter totaled 100,694 BOE/day, an increase of 12,111 BOE/day or 14% compared to first quarter production of 88,583 BOE/day, exceeding our second quarter average production guidance range of 97,500 to 100,000 BOE/day. Crude oil and natural gas liquids production increased by 16% to 52,861 bbls/day from the first quarter, meeting the high end of our second quarter crude oil and natural gas liquids guidance range of 51,500 to 53,000 bbls/day. The increase was due to the 24.7 net wells coming on-stream in North Dakota during the second quarter compared to 3.5 in the prior period. Our natural gas production increased by 11% to 287,000 Mcf/day when compared to our first quarter production of 258,568 Mcf/day, due to strong well performance in our Marcellus properties, where 1.6 net wells were brought on-steam during the period. During the second quarter, we completed the sale of certain Canadian assets with associated production of approximately 350 bbls/day.

For the three and six months ended June 30, 2019, total production increased by 7,811 BOE/day or 8%, and 5,668 BOE/day or 6%, respectively, when compared to the same periods in 2018. Our liquids growth is largely due to our continued capital investment in North Dakota and our increased natural gas production is due to strong well performance in the Marcellus.

Our crude oil and natural gas liquids weighting increased to 52% in the first six months of 2019, from 51% for the same period of 2018, due to continued investment in our North Dakota crude oil properties.

Average daily production volumes for the three and six months ended June 30, 2019 and 2018 are outlined below:

Average Daily Production Volumes	Three months ended June 30, 2019	2018	% Change	Six months ended June 30, 2019	2018	% Change
Crude oil (bbls/day)	48,141	45,242	6%	44,642	41,364	8%
Natural gas liquids (bbls/day)	4,720	4,808	(2%)	4,552	4,449	2%
Natural gas (Mcf/day)	287,000	256,995	12%	272,863	259,141	5%
Total daily sales (BOE/day)	100,694	92,883	8%	94,671	89,003	6%

As a result of strong well performance, we are increasing our average annual production guidance to 99,000 – 102,000 BOE/day from 97,000 – 101,000 BOE/day and narrowing our average annual crude oil and natural gas liquids guidance to 54,000 – 55,500 bbls/day from 53,500 – 56,000 bbls/day.

Pricing

The prices received for our 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 from the first half of 2019 to the first half of 2018 and other periods indicated:

Pricing (average for the period)	Six months ended June 30, 2019	2018	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018
Benchmarks							
WTI crude oil (US$/bbl)	$ 57.36	$ 65.37	$ 59.81	$ 54.90	$ 58.81	$ 69.50	$ 67.88
Brent (ICE) crude oil (US$/bbl)	66.11	71.04	68.32	63.90	68.08	75.97	74.90
NYMEX natural gas – last day (US$/Mcf)	2.89	2.90	2.64	3.15	3.64	2.90	2.80
USD/CDN average exchange rate	1.33	1.28	1.34	1.33	1.32	1.31	1.29
USD/CDN period end exchange rate	1.31	1.31	1.31	1.33	1.36	1.29	1.31
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 70.82	$ 75.34	$ 74.42	$ 66.56	$ 64.18	$ 83.98	$ 79.98
Natural gas liquids ($/bbl)	18.53	30.36	17.96	19.15	26.72	25.95	32.23
Natural gas ($/Mcf)	3.46	3.09	2.63	4.38	4.28	3.22	2.68
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (2.64)	$ (2.37)	$ (2.36)	$ (2.93)	$ (9.22)	$ (0.97)	$ (2.78)
Brent (ICE) – WTI (US$/bbl)	8.75	5.67	8.51	9.00	9.27	6.47	7.02
MSW Edmonton – WTI (US$/bbl)	(4.74)	(5.67)	(4.63)	(4.85)	(26.30)	(6.83)	(5.45)
WCS Hardisty – WTI (US$/bbl)	(11.48)	(21.78)	(10.67)	(12.29)	(39.43)	(22.25)	(19.27)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.33)	(0.79)	(0.43)	(0.22)	(0.39)	(0.61)	(0.91)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.68	1.46	(0.31)	1.67	0.20	(0.12)	(0.18)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (3.10)	$ (3.34)	$ (3.00)	$ (3.25)	$ (5.60)	$ (2.54)	$ (3.42)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.25)	(0.45)	(0.57)	0.13	(0.34)	(0.48)	(0.69)
Canada crude oil – WTI (US$/bbl)	(10.21)	(18.52)	(9.99)	(10.42)	(33.27)	(16.61)	(16.31)

(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 average realized crude oil sales price for the second quarter of 2019 averaged $74.42/bbl, an increase of 12% compared to the previous quarter, and directionally in line with changes in WTI benchmark pricing. Both Bakken and Canadian crude oil price differentials improved slightly from the first quarter of 2019. Our realized Bakken price differential improved by 8% during the quarter to average US$3.00/bbl below WTI. 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 our firm capacity on the Dakota Access Pipeline. For the remainder of 2019, we have physical sales contracts in place for an average of 26,300 bbls/day of Bakken crude oil production with fixed differentials averaging approximately US$2.66/bbl below WTI. Based on year to date price realizations and an improved outlook for Bakken differentials in the second half of the year, we are revising our full year Bakken differential guidance to US$3.25/bbl below WTI (from US$4.00/bbl).

Our realized price differential for our Canadian crude oil production improved by US$0.43/bbl compared to the previous quarter. Canadian crude oil prices continue to be supported by the Alberta Government production curtailment program. We have fixed differential hedges in place for 1,500 bbls/day of our Canadian heavy crude oil production at an average differential of US$14.83/bbl below WTI for the remainder of 2019.

Our realized price for natural gas liquids averaged $17.96/bbl during the second quarter, which represents a 6% decrease compared to the previous quarter. The reduction is mainly due to the continued deterioration in propane and butane pricing.

NATURAL GAS

Our average realized natural gas price during the second quarter of 2019 decreased by 40% compared to the first quarter of 2019, to average $2.63/Mcf, while NYMEX benchmark pricing decreased by 16%. With a significant portion of our sales tied to the Transco Zone 6 Non-New York market, the change in seasonal demand from winter to spring drove lower quarter over quarter pricing in this region. This along with our first quarter physical sales at markedly higher levels than the settled benchmarks resulted in a decline in our realized sales price in the second quarter when compared to the first quarter of 2019. As expected, our realized Marcellus sales differential widened to US$0.57/Mcf below NYMEX during the second quarter. We are revising our full year differential guidance for the Marcellus of US$0.30/Mcf below NYMEX to US$0.35/Mcf. We continue to expect our realized prices to improve from current levels as seasonal heating demand increases significantly in the New York markets during the fourth quarter.

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 was weaker during the first six months of 2019 with an average exchange rate of 1.33 US/CDN compared to 1.28 US/CDN for the same period in 2018. However, when compared to the exchange rate at December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar.

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 August 7, 2019, we have hedged 24,500 bbls/day of crude oil, which represents approximately 66% of our forecasted crude oil production, after royalties, for the remainder of 2019. For 2020, we have hedged 16,000 bbls/day, which represents approximately 43% of crude oil production, after royalties, based off our 2019 forecast. Our crude oil hedges in 2019 are all three-way collars, which consist of a sold put, a purchased put and a sold call. Our crude oil hedges in 2020 are all put spreads with no cap on upside participation. With both three-way collars and put spreads, if WTI prices settle below the sold put strike price, these positions provide a limited amount of protection above the WTI settled price equal 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.

We have entered into offsetting purchase transactions on our NYMEX natural gas hedges through October 2019. This has effectively locked in gains of $0.51/Mcf on our original NYMEX hedges through this term.

The following is a summary of our financial contracts in place at August 7, 2019, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)(1)		
	Jul 1, 2019 – Sep 30, 2019	**Oct 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**
Three Way Collars(2)			
Sold Puts	$ 44.64	$ 44.64	—
%	66%	66%	—
Purchased Puts	$ 54.81	$ 54.81	—
%	66%	66%	—
Sold Calls	$ 65.95	$ 65.99	—
%	66%	66%	—
Put Spreads(2)			
Sold Puts	—	—	$ 46.88
%	—	—	43%
Purchased Puts	—	—	$ 57.50
%	—	—	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.
(2) The total average deferred premium on outstanding hedges is US$2.00/bbl from July 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[1]	
	Jul 1, 2019 – Jul 31, 2019	**Aug 1, 2019 – Oct 31, 2019**
Swaps		
Sold Swaps	$2.85	$2.85
%	44%	44%
Bought Swaps	$2.34	$2.34
%	29%	44%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Cash gains/(losses):				
Crude oil	$ (5.9)	$ (20.1)	$ (7.8)	$ (26.4)
Natural gas	4.7	0.8	17.2	17.3
Total cash gains/(losses)	$ (1.2)	$ (19.3)	$ 9.4	$ (9.1)
Non-cash gains/(losses):				
Crude oil	$ 23.6	$ (70.9)	$ (63.3)	$ (100.8)
Natural gas	5.0	(0.8)	(3.5)	(1.5)
Total non-cash gains/(losses)	$ 28.6	$ (71.7)	$ (66.8)	$ (102.3)
Total gains/(losses)	$ 27.4	$ (91.0)	$ (57.4)	$ (111.4)

	Three months ended June 30,		**Six months ended June 30,**	
(Per BOE)	**2019**	**2018**	**2019**	**2018**
Total cash gains/(losses)	$ (0.13)	$ (2.28)	$ 0.55	$ (0.57)
Total non-cash gains/(losses)	3.12	(8.48)	(3.90)	(6.35)
Total gains/(losses)	$ 2.99	$ (10.76)	$ (3.35)	$ (6.92)

During the second quarter of 2019, we realized cash losses of $5.9 million on our crude oil contracts and cash gains of $4.7 million on our natural gas contracts. In comparison, during the second quarter of 2018, we realized cash losses of $20.1 million on our crude oil contracts and cash gains of $0.8 million on our natural gas contracts. Cash losses in the second quarter of 2019 on our crude oil contracts were primarily due to premiums paid on expiring three-way collars. Cash gains on our natural gas contracts were primarily due to natural gas prices falling below the swap level.

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 the end of the second quarter of 2019, the fair value of our crude oil contracts was in a net asset position of $17.2 million and the fair value of our natural gas contracts was in a net asset position of $7.4 million. For the three and six months ended June 30, 2019, the change in the fair value of our crude oil contracts represented gains of $23.6 million and losses of $63.3 million, respectively, and our natural gas contracts represented gains of $5.0 million and losses of $3.5 million, respectively.

Revenues

	Three months ended June 30,		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Oil and natural gas sales	$ 403.2	$ 406.8	$ 759.6	$ 735.3
Royalties	(81.7)	(79.4)	(150.7)	(142.9)
Oil and natural gas sales, net of royalties	$ 321.5	$ 327.4	$ 608.9	$ 592.4

Oil and natural gas sales, net of royalties, for the three and six months ended June 30, 2019, were $321.5 million and $608.9 million, respectively, a decrease of 2% and an increase of 3% from the same periods in 2018. The decrease in revenue during the second quarter of 2019 was a result of lower crude oil and natural gas liquids prices, partially offset by higher production volumes compared to the same period in 2018. The increase in revenue during the six month period ended June 30, 2019 was a result of higher production volumes and natural gas prices, partially offset by lower crude oil and natural gas liquids prices compared to the same period in 2018.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Royalties	$ 81.7	$ 79.4	$ 150.7	$ 142.9
Per BOE	$ 8.92	$ 9.40	$ 8.79	$ 8.87
Production taxes	$ 21.4	$ 22.6	$ 36.1	$ 38.8
Per BOE	$ 2.34	$ 2.68	$ 2.11	$ 2.41
Royalties and production taxes	$ 103.1	$ 102.0	$ 186.8	$ 181.7
Per BOE	$ 11.26	$ 12.08	$ 10.90	$ 11.28
Royalties and production taxes (% of oil and natural gas sales)	26%	25%	25%	25%

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. During the three and six months ended June 30, 2019, royalties and production taxes increased slightly to $103.1 million and $186.8 million, respectively, from $102.0 million and $181.7 million for the same periods in 2018, primarily due to higher U.S. crude oil sales.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2019.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Cash operating expenses	$ 71.8	$ 61.0	$ 141.6	$ 114.7
Non-cash (gains)/losses[1]	—	(0.1)	—	(0.1)
Total operating expenses	$ 71.8	$ 60.9	$ 141.6	$ 114.6
Per BOE	$ 7.84	$ 7.20	$ 8.26	$ 7.12

(1) Non-cash (gains)/losses on fixed price electricity swaps.

For the three and six months ended June 30, 2019, operating expenses were $71.8 million or $7.84/BOE and $141.6 million or $8.26/BOE, respectively, representing an increase of $10.9 million and $27.0 million from the same periods in 2018. The increase is mainly attributable to our higher North Dakota crude oil and natural gas liquids volumes, higher gas facility charges and well service activity in 2019.

We are reducing our annual operating cost guidance of $8.00/BOE to $7.90/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Transportation costs	$ 36.8	$ 30.1	$ 68.1	$ 57.0
Per BOE	$ 4.02	$ 3.56	$ 3.97	$ 3.54

For the three and six months ended June 30, 2019, transportation costs were $36.8 million or $4.02/BOE and $68.1 million or $3.97/BOE, respectively, compared to our annual guidance of $4.00/BOE. During the same periods in 2018, transportation costs were $30.1 million or $3.56/BOE and $57.0 million or $3.54/BOE. The increase is due to additional crude oil firm transportation commitments that provide access to sell a portion of our production at the U.S. Gulf Coast or Brent pricing that commenced March 1, 2019 and a weaker Canadian dollar when compared to the prior periods.

We are maintaining our annual guidance for transportation costs of $4.00/BOE.

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 June 30, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	56,602 BOE/day	264,554 Mcfe/day	100,694 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 65.29	$ 2.78	$ 44.00
Royalties and production taxes	(17.51)	(0.54)	(11.26)
Cash operating expenses	(12.54)	(0.30)	(7.84)
Transportation costs	(3.02)	(0.88)	(4.02)
Netback before hedging	$ 32.22	$ 1.06	$ 20.88
Cash hedging gains/(losses)	(1.14)	0.19	(0.13)
Netback after hedging	$ 31.08	$ 1.25	$ 20.75
Netback before hedging ($ millions)	$ 166.0	$ 25.5	$ 191.5
Netback after hedging ($ millions)	$ 160.1	$ 30.2	$ 190.3

	Three months ended June 30, 2018		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	53,624 BOE/day	235,554 Mcfe/day	92,883 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 71.65	$ 2.67	$ 48.13
Royalties and production taxes	(18.66)	(0.51)	(12.08)
Cash operating expenses	(10.95)	(0.35)	(7.21)
Transportation costs	(2.41)	(0.86)	(3.56)
Netback before hedging	$ 39.63	$ 0.95	$ 25.28
Cash hedging gains/(losses)	(4.12)	0.04	(2.28)
Netback after hedging	$ 35.51	$ 0.99	$ 23.00
Netback before hedging ($ millions)	$ 193.4	$ 20.3	$ 213.7
Netback after hedging ($ millions)	$ 173.3	$ 21.1	$ 194.4

	Six months ended June 30, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	52,767 BOE/day	251,426 Mcfe/day	94,671 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 62.64	$ 3.55	$ 44.33
Royalties and production taxes	(16.32)	(0.68)	(10.90)
Cash operating expenses	(13.19)	(0.34)	(8.26)
Transportation costs	(2.90)	(0.89)	(3.97)
Netback before hedging	$ 30.23	$ 1.64	$ 21.20
Cash hedging gains/(losses)	(0.82)	0.38	0.55
Netback after hedging	$ 29.41	$ 2.02	$ 21.75
Netback before hedging ($ millions)	$ 288.6	$ 74.5	$ 363.1
Netback after hedging ($ millions)	$ 280.8	$ 91.7	$ 372.5

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

	Six months ended June 30, 2018		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	48,890 BOE/day	240,678 Mcfe/day	89,003 BOE/day
Netback(1) $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 67.73	$ 3.12	$ 45.65
Royalties and production taxes	(17.67)	(0.58)	(11.28)
Cash operating expenses	(10.87)	(0.42)	(7.12)
Transportation costs	(2.26)	(0.86)	(3.54)
Netback before hedging	$ 36.93	$ 1.26	$ 23.71
Cash hedging gains/(losses)	(2.99)	0.40	(0.57)
Netback after hedging	$ 33.94	$ 1.66	$ 23.14
Netback before hedging ($ millions)	$ 326.8	$ 55.1	$ 381.9
Netback after hedging ($ millions)	$ 300.4	$ 72.4	$ 372.8

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

Crude oil netbacks before hedging for the three and six months ended June 30, 2019 were lower compared to the same periods in 2018 primarily due to weaker realized prices and higher operating and transportation expenses. Natural gas netbacks before hedging were higher for the three and six months ended June 30, 2019 compared to the same periods in 2018 mainly due to higher realized prices. For the three and six months ended June 30, 2019, our crude oil properties accounted for 87% and 79% of our total netback before hedging, respectively, compared to 91% and 86% during the same periods in 2018.

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.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Cash:				
G&A expense	$ 11.5	$ 12.1	$ 23.9	$ 25.3
Share-based compensation expense	(0.6)	0.5	0.7	2.4
Non-Cash:				
Share-based compensation expense	4.3	5.0	12.3	14.1
Equity swap loss/(gain)	0.2	(0.4)	0.1	(1.4)
G&A expense	0.3	—	0.4	—
Total G&A expenses	$ 15.7	$ 17.2	$ 37.4	$ 40.4

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2019	2018	2019	2018
Cash:				
G&A expense	$ 1.26	$ 1.44	$ 1.39	$ 1.57
Share-based compensation expense	(0.07)	0.05	0.04	0.16
Non-Cash:				
Share-based compensation expense	0.47	0.59	0.72	0.87
Equity swap loss/(gain)	0.03	(0.04)	0.01	(0.09)
G&A expense	0.03	—	0.02	—
Total G&A expenses	$ 1.72	$ 2.04	$ 2.18	$ 2.51

For the three and six months ended June 30, 2019, cash G&A expenses were $11.5 million or $1.26/BOE and $23.9 million or $1.39/BOE, respectively, compared to $12.1 million or $1.44/BOE and $25.3 million or $1.57/BOE for the same periods in 2018. Cash G&A expenses decreased on a per BOE basis compared to the same periods in 2018, due to higher production.

During the second quarter of 2019, we reported a cash SBC recovery of $0.6 million due to the decrease in our share price on outstanding deferred share units. In comparison, during the same period of 2018, we recorded cash SBC expense of $0.5 million due to an increase in our share price on outstanding deferred share units. We recorded non-cash SBC expense of $4.3 million or $0.47/BOE in the second quarter of 2019, a decrease from an expense of $5.0 million or $0.59/BOE during the same period in 2018.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the second quarter, we recorded a non-cash mark-to-market loss of $0.2 million on these hedges due to the decrease in our share price, compared to a gain of $0.4 million recorded for the same period in 2018. We had 264,000 units outstanding, hedged at a weighted average price of $17.82 per share at June 30, 2019.

Based on higher annual production levels we are lowering our annual cash G&A guidance to $1.45/BOE from $1.50/BOE.

Interest Expense

For the three and six months ended June 30, 2019, we recorded total interest expense of $8.7 million and $17.1 million, respectively, compared to $9.2 million and $18.4 million for the same periods in 2018. The decrease in interest expense for the three and six months ended June 30, 2019 compared to the same periods in 2018 was primarily due to the repayment of a portion of our 2009 and 2012 senior notes, partially offset by a weaker Canadian dollar on our U.S. dollar denominated interest expense.

At June 30, 2019, all of our debt was based on fixed interest rates, 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 June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Realized:				
Foreign exchange (gain)/loss on settlements	$ 0.1	$ 0.2	$ —	$ 0.3
Translation of U.S. dollar cash held in Canada (gain)/loss	4.1	(3.7)	9.3	(11.0)
Unrealized (gain)/loss	(16.5)	12.4	(33.6)	30.0
Total foreign exchange (gain)/loss	$ (12.3)	$ 8.9	$ (24.3)	$ 19.3
USD/CDN average exchange rate	1.34	1.29	1.33	1.28
USD/CDN period end exchange rate	1.31	1.31	1.31	1.31

For the three and six months ended June 30, 2019, we recorded foreign exchange gains of $12.3 million and $24.3 million, respectively, compared to losses of $8.9 million and $19.3 million for the same periods in 2018. 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 gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing the period end exchange rate at June 30, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $33.6 million. See Note 13 to the Interim Financial Statements for further details.

Capital Investment

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Capital spending(1)	$ 207.2	$ 177.1	$ 368.0	$ 328.6
Office capital(1)	2.1	2.3	3.3	3.7
Line fill	—	—	5.1	—
Sub-total	209.3	179.4	376.4	332.3
Property and land acquisitions	$ 1.9	$ 2.4	$ 4.9	$ 14.7
Property divestments	(9.6)	0.2	(10.1)	(6.8)
Sub-total	(7.7)	2.6	(5.2)	7.9
Total	$ 201.6	$ 182.0	$ 371.2	$ 340.2

(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 and six months ended June 30, 2019 totaled $207.2 million and $368.0 million, respectively, compared to the spending of $177.1 million and $328.6 million for the same periods in 2018. The increase in spending is in line with our strategy to deliver production and liquids growth through 2019. During the second quarter, we spent $186.6 million on our U.S. crude oil properties, $13.7 million on our Marcellus natural gas assets and $6.1 million on our Canadian waterflood properties. During the six months ended June 30, 2019, we spent $5.1 million on line fill to meet the requirements of a multi-year transportation contract, which began in March 2019.

In the second quarter of 2019, we completed $1.9 million in property and land acquisitions, which included minor interests in leases and undeveloped land, compared to $2.4 million for the same period in 2018. Property divestments for the three months ended June 30, 2019 were $9.6 million, which primarily related to the divestment of properties in Southeastern Saskatchewan with associated production of approximately 350 bbls/day.

We are narrowing our 2019 annual capital spending guidance range to $610 million – $630 million from $590 million – $630 million.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2019	2018	2019	2018
DD&A expense	$ 88.3	$ 73.2	$ 164.2	$ 137.2
Per BOE	$ 9.64	$ 8.66	$ 9.58	$ 8.52

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2019, DD&A increased to $88.3 million and $164.2 million, respectively, compared to $73.2 million and $137.2 million for the same periods in 2018, as a result of additional U.S. production with higher depletion rates and a weaker Canadian dollar.

Asset Retirement Obligation

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation, using a weighted average credit-adjusted risk-free rate of 5.55%, to be $127.1 million at June 30, 2019, compared to 5.59% and $126.1 million at December 31, 2018. For the three and six months ended June 30, 2019, asset retirement obligation settlements were $0.5 million and $5.9 million, respectively, compared to $2.1 million and $5.4 million during the same periods in 2018. See Note 9 to the Interim Financial Statements for further details.

Leases

On January 1, 2019, we adopted ASU 842 – *Leases*, which requires the recognition of 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 included on our balance sheet are based on the present value of lease payments over the lease term. Total ROU assets included on our balance sheet represent our right to use an underlying asset for the lease term. At June 30, 2019, our total lease liability was $61.1 million. In addition, ROU assets of $60.7 million were recorded, which equates to our lease liabilities less non-cash lease incentives. See Note 3(a) and Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Current tax expense/(recovery)	$ (13.9)	$ 0.1	$ (19.5)	$ 0.1
Deferred tax expenses/(recovery)	48.8	3.2	30.9	15.7
Total tax expense/(recovery)	$ 34.9	$ 3.3	$ 11.4	$ 15.8

For the three and six months ended June 30, 2019, we recorded a current tax recovery of $13.9 and $19.5 million, respectively, compared to an expense of $0.1 million for each of the same periods in 2018. The recoveries primarily relate to the favorable settlement of a tax dispute in Canada in the second quarter of 2019 and the reversal of the reserve recorded at December 31, 2018 for the sequestered portion of our U.S. AMT refund in the first quarter of 2019.

For the three and six months ended June 30, 2019, we recorded deferred tax expense of $48.8 million and $30.9 million, respectively, compared to an expense of $3.2 million and $15.7 million, for the same periods in 2018. The increase in the deferred tax expense during the second quarter was primarily due to a $26.3 million expense recorded for the remeasurement of our Canadian net deferred income tax asset for the change in the Alberta corporate income tax rate from 12% to 8% by 2022. See Note 14 to the Interim Financial Statements for further details.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant 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 June 30, 2019, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 0.5x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at June 30, 2019 was $359.0 million, an increase of 8% compared to $333.5 million at December 31, 2018. Total debt was comprised of $611.5 million of senior notes less $252.5 million in cash. During the second quarter, we repaid a portion of our 2009 and 2012 senior notes, resulting in a $59.4 million decrease to our outstanding debt.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 116% and 110% for the three and six months ended June 30, 2019, respectively, compared to 107% and 106% for the same periods in 2018.

For the three months ended June 30, 2019, the Company repurchased and cancelled approximately 6.6 million shares under our NCIB for a total cost of $70.6 million. In total in 2019, the Company has allocated $90.4 million in capital to the repurchase and cancellation of approximately 8.4 million shares under our current and previous NCIB.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $269.3 million at June 30, 2019 from $143.1 million at December 31, 2018. This increase is primarily due to the reclassification of a portion of our 2009 and 2012 senior notes from long-term debt to current liabilities and an increase in accounts payable due to higher capital spending in the second quarter of 2019 when compared to the fourth quarter of 2018. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, cash flow from operations and our $800 million bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

At June 30, 2019, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

Our net debt to adjusted funds flow remains at 0.5x and the following table lists our financial covenants as at June 30, 2019:

Covenant Description		June 30, 2019
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	0.8x
Total debt to adjusted EBITDA (1)	4.0x	0.8x
Total debt to capitalization	50%	17%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	0.8x
Senior debt to consolidated present value of total proved reserves(3)	60%	18%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	21.6x

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 June 30, 2019 was $176.6 million and $767.5 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

($ millions, except per share amounts)	Three months ended June 30, 2019	2018	Six months ended June 30, 2019	2018
Dividends to shareholders[1]	$ 7.0	$ 7.3	$ 14.2	$ 14.7
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.06	$ 0.06

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

During the three and six months ended June 30, 2019, we reported total dividends of $7.0 million or $0.03 per share and $14.2 million or $0.06 per share, respectively, compared to $7.3 million or $0.03 per share and $14.7 million or $0.06 per share for the same periods in 2018.

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

Shareholders' Capital

	Six months ended June 30, 2019	2018
Share capital ($ millions)	$ 3,225.6	$ 3,415.0
Common shares outstanding (thousands)	231,616	244,984
Weighted average shares outstanding – basic (thousands)	237,197	244,369
Weighted average shares outstanding – diluted (thousands)	239,947	249,367

For the six months ended June 30, 2019, a total of 1,007,234 units vested pursuant to our treasury settled LTI plans (2018 – 2,539,498). In total, 564,000 shares were issued from treasury and $4.4 million was transferred from paid-in capital to share capital (2018 – 2,539,498; $23.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2019 – $5.0 million, 2018 – nil).

For the six months ended June 30, 2019, no shares were issued pursuant to our stock option plan, resulting in no additional share capital (2018 – 315,843; $4.3 million).

On March 21, 2019, Enerplus announced the renewal of its NCIB to purchase up to 16,673,015 common shares, representing 7% of the "public float" of Enerplus (within the meaning under the rules of the Toronto Stock Exchange (the "TSX")) through the facilities of the TSX, the New York Stock Exchange and/or alternative Canadian trading systems during the 12-month period ending March 25, 2020.

During the six months ended June 30, 2019, the Company repurchased 8,358,821 common shares under the previous and current NCIB at an average price of $10.80 per share, for total consideration of $90.4 million. Of the amount paid, $116.4 million was charged to share capital and $26.0 million was credited to accumulated deficit. Subsequent to the quarter and up to August 7, 2019, the Company repurchased 981,266 common shares under the NCIB at an average price of $8.97 per share, for total consideration of $8.8 million.

On May 23, 2019, we filed a short form base shelf prospectus (the “Shelf Prospectus”) with securities regulatory authorities in each of the provinces of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains in place.

At August 7, 2019, we had 230,635,015 common shares outstanding. In addition, an aggregate of 7,958,372 common shares may be issued to settle outstanding grants under the Performance Share Unit (“PSU”), Restricted Share Unit, and stock option plans, assuming the maximum payout 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

($ millions, except per unit amounts)	Three months ended June 30, 2019 Canada	U.S.	Total	Three months ended June 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,749	39,392	48,141	9,212	36,030	45,242
Natural gas liquids (bbls/day)	931	3,789	4,720	1,055	3,753	4,808
Natural gas (Mcf/day)	23,120	263,880	287,000	29,151	227,844	256,995
Total average daily production (BOE/day)	13,533	87,161	100,694	15,126	77,757	92,883
Pricing[2]						
Crude oil (per bbl)	$ 67.12	$ 76.04	$ 74.42	$ 66.58	$ 83.41	$ 79.98
Natural gas liquids (per bbl)	25.31	16.16	17.96	50.20	27.18	32.23
Natural gas (per Mcf)	1.82	2.71	2.63	2.07	2.76	2.68
Capital Expenditures						
Capital spending	$ 7.0	$ 200.2	$ 207.2	$ 11.4	$ 165.7	$ 177.1
Acquisitions	1.1	0.8	1.9	1.0	1.4	2.4
Divestments	(9.4)	(0.2)	(9.6)	0.2	—	0.2
Netback[3] Before Hedging						
Oil and natural gas sales	$ 60.1	$ 343.1	$ 403.2	$ 66.9	$ 339.9	$ 406.8
Royalties	(12.7)	(69.0)	(81.7)	(10.7)	(68.7)	(79.4)
Production taxes	(0.2)	(21.2)	(21.4)	(0.7)	(21.9)	(22.6)
Cash operating expenses	(17.5)	(54.3)	(71.8)	(17.7)	(43.3)	(61.0)
Transportation costs	(2.6)	(34.2)	(36.8)	(2.8)	(27.3)	(30.1)
Netback before hedging	$ 27.1	$ 164.4	$ 191.5	$ 35.0	$ 178.7	$ 213.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (27.4)	$ —	$ (27.4)	$ 91.0	$ —	$ 91.0
Total G&A[4]	(1.9)	17.6	15.7	6.3	10.9	17.2
Current income tax expense/(recovery)	(13.9)	—	(13.9)	—	0.1	0.1

($ millions, except per unit amounts)	Six months ended June 30, 2019 Canada	U.S.	Total	Six months ended June 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	8,873	35,769	44,642	9,362	32,002	41,364
Natural gas liquids (bbls/day)	957	3,595	4,552	1,151	3,298	4,449
Natural gas (Mcf/day)	23,730	249,133	272,863	31,131	228,010	259,141
Total average daily production (BOE/day)	13,785	80,886	94,671	15,701	73,302	89,003
Pricing[2]						
Crude oil (per bbl)	$ 63.06	$ 72.75	$ 70.82	$ 59.63	$ 79.94	$ 75.34
Natural gas liquids (per bbl)	30.71	15.29	18.53	47.46	24.39	30.36
Natural gas (per Mcf)	3.26	3.48	3.46	2.63	3.16	3.09
Capital Expenditures						
Capital spending	$ 24.5	$ 343.5	$ 368.0	$ 24.6	$ 304.0	$ 328.6
Acquisitions	2.1	2.8	4.9	2.1	12.6	14.7
Divestments	(9.5)	(0.6)	(10.1)	(0.7)	(6.1)	(6.8)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 121.9	$ 637.7	$ 759.6	$ 127.6	$ 607.7	$ 735.3
Royalties	(21.7)	(129.0)	(150.7)	(20.7)	(122.2)	(142.9)
Production taxes	(0.9)	(35.2)	(36.1)	(1.5)	(37.3)	(38.8)
Cash operating expenses	(38.4)	(103.2)	(141.6)	(38.2)	(76.5)	(114.7)
Transportation costs	(5.3)	(62.8)	(68.1)	(5.8)	(51.2)	(57.0)
Netback before hedging	$ 55.6	$ 307.5	$ 363.1	$ 61.4	$ 320.5	$ 381.9
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 57.4	$ —	$ 57.4	$ 111.4	$ —	$ 111.4
Total G&A[4]	11.3	26.1	37.4	21.7	18.7	40.4
Current income tax expense/(recovery)	(14.0)	(5.5)	(19.5)	—	0.1	0.1

(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
2019				
Second Quarter	$ 321.4	$ 85.1	$ 0.36	$ 0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 608.9	$ 104.3	$ 0.44	$ 0.43
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
2017				
Fourth Quarter	$ 271.1	$ 15.3	$ 0.06	$ 0.06
Third Quarter	196.1	16.1	0.07	0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 920.7	$ 237.0	$ 0.98	$ 0.96

Oil and natural gas sales, net of royalties, increased by $34.0 million in the second quarter of 2019 compared to the first quarter of 2019, due to increased production volumes. Net income increased in the second quarter of 2019 due to increased sales and a gain of $27.4 million on commodity derivative instruments, compared to a loss of $84.9 million during the first quarter of 2019.

Oil and natural gas sales, net of royalties, improved in 2018 compared to 2017 due to an increase in realized commodity prices and a higher weighting of crude oil and natural gas liquids as a proportion of total production. As a result, net income also improved in 2018, excluding the effects of a gain which was recorded on asset divestments in the second quarter of 2017.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2019, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2019 UPDATED GUIDANCE

We are increasing our average annual production guidance to 99,000 – 102,000 BOE/day and revising our average annual crude oil and natural gas liquids guidance to 54,000 – 55,500 bbls/day.

We are narrowing our 2019 capital spending guidance to $610 – $630 million from our previous range of $590 – $630 million. With higher average annual production, we are reducing our annual operating expense guidance to $7.90/BOE from $8.00/BOE and reducing our annual cash G&A guidance to $1.45/BOE from $1.50/BOE.

We are decreasing our full year Bakken differential guidance to US$3.25/bbl below WTI from US$4.00/bbl. We are also increasing our full year Marcellus differential guidance to US$0.35/Mcf below NYMEX from $0.30/Mcf.

All other guidance targets remain unchanged. This guidance does not include any additional acquisitions or divestments.

Summary of 2019 Expectations	Target
Capital spending	$610 - $630 million (from $590 - $630 million)
Average annual production	99,000 - 102,000 BOE/day (from 97,000 - 101,000 BOE/day)
Average annual crude oil and natural gas liquids production	54,000 - 55,500 bbls/day (from 53,500 - 56,000 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.90/BOE (from $8.00/BOE)
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.45/BOE (from $1.50/BOE)

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.25)/bbl (from US$(4.00)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.35)/Mcf (from US$(0.30)/Mcf)

(1) Excludes transportation costs.

NON-GAAP MEASURES

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

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

Calculation of Netback	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Oil and natural gas sales	$ 403.2	$ 406.8	$ 759.6	$ 735.3
Less:				
Royalties	(81.7)	(79.4)	(150.7)	(142.9)
Production taxes	(21.4)	(22.6)	(36.1)	(38.8)
Cash operating expenses	(71.8)	(61.0)	(141.6)	(114.7)
Transportation costs	(36.8)	(30.1)	(68.1)	(57.0)
Netback before hedging	$ 191.5	$ 213.7	$ 363.1	$ 381.9
Cash gains/(losses) on derivative instruments	(1.2)	(19.3)	9.4	(9.1)
Netback after hedging	$ 190.3	$ 194.4	$ 372.5	$ 372.8

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Cash flow from operating activities	$ 237.0	$ 141.8	$ 345.9	$ 301.1
Asset retirement obligation expenditures	0.5	2.0	5.9	5.4
Changes in non-cash operating working capital	(51.5)	29.9	3.0	22.4
Adjusted funds flow	$ 186.0	$ 173.7	$ 354.8	$ 328.9

"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 June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Adjusted funds flow	$ 186.0	$ 173.7	$ 354.8	$ 328.9
Capital spending	(207.2)	(177.1)	(368.0)	(328.6)
Free cash flow	$ (21.2)	$ (3.4)	$ (13.2)	$ 0.3

"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 and the impact of statutory changes to the Company's corporate tax rate.

Calculation of Adjusted Net Income	Three months ended June 30,		Six months ended June 30,	
($ millions)	2019	2018	2019	2018
Net income/(loss)	$ 85.1	$ 12.4	$ 104.3	$ 42.0
Unrealized derivative instrument (gain)/loss	(28.4)	71.2	67.0	100.8
Unrealized foreign exchange (gain)/loss	(16.5)	12.4	(33.6)	30.0
Tax effect on above items	7.8	(19.1)	(17.1)	(27.5)
Income tax rate adjustment on deferred taxes	26.3	—	26.3	—
Adjusted net income	$ 74.3	$ 76.9	$ 146.9	$ 145.3

"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 our 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 June 30,**		**Six months ended June 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Dividends	$ 7.0	$ 7.3	$ 14.2	$ 14.7
Capital, office expenditures and line fill	209.3	179.4	376.4	332.3
Sub-total	$ 216.3	$ 186.7	$ 390.6	$ 347.0
Adjusted funds flow	$ 186.0	$ 173.7	$ 354.8	$ 328.9
Adjusted payout ratio (%)	116%	107%	110%	106%

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

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**June 30, 2019**
Net income/(loss)	$ 440.5
Add:	
Interest	35.5
Current and deferred tax expense/(recovery)	98.8
DD&A and asset impairment	331.3
Other non-cash charges(2)	(138.6)
Adjusted EBITDA	$ 767.5

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2019 include the six months ended June 30, 2019 and the third and fourth quarter of 2018.
(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 June 30, 2019, 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 April 1, 2019 and ended June 30, 2019 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 2019 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2019 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; expected operating and transportation costs; our anticipated shares repurchases under current and future normal course issuer bids; capital spending levels in 2019 and impact thereof on our production levels and land holdings; 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; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; 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 will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our updated 2019 guidance contained in this MD&A is based on the rest of the year prices of: a WTI price of US$56.00/bbl, a NYMEX price of US$2.30/Mcf, and a USD/CDN exchange rate of 1.31. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF, our Annual MD&A and Form 40-F as at December 31, 2018).

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	June 30, 2019	December 31, 2018
Assets			
Current Assets			
Cash and cash equivalents		$ 252,531	$ 363,327
Accounts receivable	4	158,290	145,206
Income tax receivable	14	43,542	55,172
Derivative financial assets	16	21,347	59,258
Other current assets		1,931	8,928
		477,641	631,891
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	5	1,456,502	1,293,941
Other capital assets, net	5	19,569	13,130
Property, plant and equipment		1,476,071	1,307,071
Right-of-use assets	3,10	60,717	—
Goodwill		646,704	654,799
Derivative financial assets	16	3,408	32,220
Deferred income tax asset	14	423,997	465,124
Income tax receivable	14	—	27,195
Total Assets		$ 3,088,538	$ 3,118,300
Liabilities			
Current liabilities			
Accounts payable	7	$ 346,911	$ 290,045
Dividends payable		2,318	2,395
Current portion of long-term debt	8	106,855	60,001
Derivative financial liabilities	16	2,161	1,909
Current portion of lease liabilities	3,10	16,974	—
		475,219	354,350
Long-term debt	8	504,682	636,849
Asset retirement obligation	9	127,098	126,112
Lease liabilities	3,10	44,098	—
		675,878	762,961
Total Liabilities		1,151,097	1,117,311
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: June 30, 2019 – 232 million shares			
December 31, 2018 – 239 million shares	15	3,225,591	3,337,608
Paid-in capital		49,472	46,524
Accumulated deficit		(1,655,999)	(1,772,084)
Accumulated other comprehensive income/(loss)		318,377	388,941
		1,937,441	2,000,989
Total Liabilities & Shareholders' Equity		$ 3,088,538	$ 3,118,300

Commitments and Contingencies	17
Subsequent events	15

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 June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Revenues					
Oil and natural gas sales, net of royalties	11	$ 321,463	$ 327,384	$ 608,915	$ 592,404
Commodity derivative instruments gain/(loss)	16	27,422	(90,951)	(57,445)	(111,415)
		348,885	236,433	551,470	480,989
Expenses					
Operating		71,818	60,879	141,611	114,640
Transportation		36,803	30,123	68,094	57,044
Production taxes		21,442	22,649	36,057	38,784
General and administrative	12	15,680	17,189	37,390	40,413
Depletion, depreciation and accretion		88,315	73,165	164,226	137,211
Interest		8,693	9,249	17,086	18,352
Foreign exchange (gain)/loss	13	(12,251)	8,911	(24,277)	19,282
Other expense/(income)		(1,568)	(1,447)	(4,430)	(2,630)
		228,932	220,718	435,757	423,096
Income/(Loss) before taxes		119,953	15,715	115,713	57,893
Current income tax expense/(recovery)	14	(13,928)	72	(19,458)	138
Deferred income tax expense/(recovery)	14	48,797	3,239	30,929	15,714
Net Income/(Loss)		$ 85,084	$ 12,404	$ 104,242	$ 42,041
Other Comprehensive Income/(Loss)					
Change in cumulative translation adjustment		(34,208)	27,990	(70,564)	62,358
Total Comprehensive Income/(Loss)		$ 50,876	$ 40,394	$ 33,678	$ 104,399
Net income/(Loss) per share					
Basic	15	$ 0.36	$ 0.05	$ 0.44	$ 0.17
Diluted	15	$ 0.36	$ 0.05	$ 0.43	$ 0.17

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 June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Share Capital				
Balance, beginning of period	$ 3,317,855	$ 3,411,878	$ 3,337,608	$ 3,386,946
Purchase of common shares under Normal Course Issuer Bid	(92,264)	—	(116,423)	—
Share-based compensation – treasury settled	—	—	4,406	23,389
Stock Option Plan – cash	—	2,915	—	4,344
Stock Option Plan – exercised	—	251	—	365
Balance, end of period	$ 3,225,591	$ 3,415,044	$ 3,225,591	$ 3,415,044
Paid-in Capital				
Balance, beginning of period	$ 45,209	$ 60,951	$ 46,524	$ 75,375
Share-based compensation – cash settled (tax withholding)	—	—	(4,952)	—
Share-based compensation – treasury settled	—	—	(4,406)	(23,389)
Share-based compensation – non-cash	4,263	4,997	12,306	14,076
Stock Option Plan – exercised	—	(251)	—	(365)
Balance, end of period	$ 49,472	$ 65,697	$ 49,472	$ 65,697
Accumulated Deficit				
Balance, beginning of period	$ (1,755,757)	$ (2,102,359)	$ (1,772,084)	$ (2,124,676)
Purchase of common shares under Normal Course Issuer Bid	21,708	—	26,039	—
Net income/(loss)	85,084	12,404	104,242	42,041
Dividends declared ($0.01 per share)	(7,034)	(7,347)	(14,196)	(14,667)
Balance, end of period	$ (1,655,999)	$ (2,097,302)	$ (1,655,999)	$ (2,097,302)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ 352,585	$ 297,492	$ 388,941	$ 263,124
Change in cumulative translation adjustment	(34,208)	27,990	(70,564)	62,358
Balance, end of period	$ 318,377	$ 325,482	$ 318,377	$ 325,482
Total Shareholders' Equity	$ 1,937,441	$ 1,708,921	$ 1,937,441	$ 1,708,921

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 June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Operating Activities					
Net income/(loss)		$ 85,084	$ 12,404	$ 104,242	$ 42,041
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		88,315	73,165	164,226	137,211
Changes in fair value of derivative instruments	16	(28,353)	71,213	66,975	100,835
Deferred income tax expense/(recovery)	14	48,797	3,239	30,929	15,714
Foreign exchange (gain)/loss on debt and working capital	13	(16,498)	12,386	(33,602)	30,035
Share-based compensation and general and administrative	12,15	4,535	4,997	12,669	14,076
Translation of U.S. dollar cash held in Canada	13	4,158	(3,696)	9,354	(11,042)
Asset retirement obligation expenditures	9	(503)	(2,053)	(5,893)	(5,384)
Changes in non-cash operating working capital	18	51,456	(29,888)	(2,958)	(22,419)
Cash flow from/(used in) operating activities		236,991	141,767	345,942	301,067
Financing Activities					
Senior notes	8	(59,429)	(29,044)	(59,429)	(29,044)
Proceeds from the issuance of shares	15	—	2,915	—	4,344
Purchase of common shares under Normal Course Issuer Bid	15	(70,556)	—	(90,384)	—
Share-based compensation – cash settled (tax withholding)	15	—	—	(4,952)	—
Dividends	15,18	(7,099)	(7,344)	(14,273)	(14,638)
Cash flow from/(used in) financing activities		(137,084)	(33,473)	(169,038)	(39,338)
Investing Activities					
Capital and office expenditures	18	(168,282)	(147,898)	(280,077)	(256,110)
Property and land acquisitions		(1,911)	(2,392)	(4,892)	(8,582)
Property divestments		9,601	(182)	10,023	706
Cash flow from/(used in) investing activities		(160,592)	(150,472)	(274,946)	(263,986)
Effect of exchange rate changes on cash and cash equivalents		(5,780)	6,205	(12,754)	16,131
Change in cash and cash equivalents		(66,465)	(35,973)	(110,796)	13,874
Cash and cash equivalents, beginning of period		318,996	396,395	363,327	346,548
Cash and cash equivalents, end of period		**$ 252,531**	**$ 360,422**	**$ 252,531**	**$ 360,422**

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 and six months ended June 30, 2019 and the 2018 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, 2018. There are no differences in the use of estimates or judgments between these interim Consolidated Financial Statements and the annual audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2018.

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.

3) ACCOUNTING POLICY CHANGES

a) Recently adopted accounting standards

Enerplus adopted ASC 842 *Leases* effective January 1, 2019 as detailed below. Enerplus used the modified retrospective method to adopt the new standard, with ASC 842 applied to all contracts not yet completed as of the date of adoption with the cumulative effect on comparative periods reflected as an adjustment to retained earnings, if applicable. The most significant impact was the recognition of right-of-use ("ROU") assets and lease liabilities for operating leases, while accounting for finance leases and lessor accounting remained unchanged.

Enerplus elected the practical expedient related to land easements, allowing it to carry forward its accounting treatment for land easements on existing agreements.

The impacts of the adoption of ASC 842 as at January 1, 2019 are as follows:

($ thousands)	As reported as at December 31, 2018	Adjustments	Balance as at January 1, 2019
Right-of-use assets	$ —	$ 50,193	$ 50,193
Current portion of lease liabilities	—	(10,648)	(10,648)
Lease liabilities	—	(39,545)	(39,545)
Total	$ —	$ —	$ —

The standard did not materially impact the Company's Consolidated Statement of Income/(Loss) or cash flows.

As a result of this adoption, Enerplus has revised its accounting policy for leases as follows:

Leases

Enerplus determines if an arrangement is a lease at inception. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Operating and finance leases are included in right-of-use assets, current lease liabilities, and long-term lease liabilities in the Consolidated Balance Sheets.

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

Lease agreements contain both lease and non-lease components which are accounted for separately. For certain equipment leases, a portfolio approach is applied to effectively account for the ROU assets and liabilities. Prior to January 1, 2019, the Company applied lease accounting in accordance with ASC 840.

b) Future accounting changes

In future accounting periods, the Company will adopt the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses (Topic 326)*. The ASU significantly changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020, and will be applied using a modified retrospective approach. Enerplus does not expect to early adopt the standard and continues to assess the impact it will have on the Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)*. This standard eliminates Step 2 of the goodwill impairment test and requires a goodwill impairment charge for the amount that the carrying amount of the reporting unit exceeds the reporting unit's fair value. The updated guidance is effective January 1, 2020. Early adoption is permitted. The amended standard may affect goodwill impairment tests past the adoption date, the impact of which is not known.

4) ACCOUNTS RECEIVABLE

($ thousands)	June 30, 2019	December 31, 2018
Accrued revenue	$ 119,477	$ 118,821
Accounts receivable – trade	42,629	30,252
Allowance for doubtful accounts	(3,816)	(3,867)
Total accounts receivable, net of allowance for doubtful accounts	$ 158,290	$ 145,206

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

As of June 30, 2019 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties(1)	$ 14,859,006	$ (13,402,504)	$ 1,456,502
Other capital assets	122,994	(103,425)	19,569
Total PP&E	$ 14,982,000	$ (13,505,929)	$ 1,476,071

As of December 31, 2018 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties(1)	$ 14,773,082	$ (13,479,141)	$ 1,293,941
Other capital assets	115,510	(102,380)	13,130
Total PP&E	$ 14,888,592	$ (13,581,521)	$ 1,307,071

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

6) ASSET IMPAIRMENT

There was no impairment recorded for the six months ended June 30, 2019 and 2018.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from June 30, 2018 through June 30, 2019:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q2 2019	$ 61.38	$ 66.07	$ 3.02	1.32
Q1 2019	63.00	67.30	3.07	1.32
Q4 2018	65.56	69.58	3.10	1.28
Q3 2018	63.43	74.38	2.92	1.28
Q2 2018	57.67	67.77	2.92	1.27

7) ACCOUNTS PAYABLE

($ thousands)	June 30, 2019	December 31, 2018
Accrued payables	$ 151,764	$ 115,388
Accounts payable – trade	195,147	174,657
Total accounts payable	$ 346,911	$ 290,045

8) DEBT

($ thousands)	June 30, 2019	December 31, 2018
Current:		
Senior notes	$ 106,855	$ 60,001
Long-term:		
Bank credit facility	—	—
Senior notes	504,682	636,849
Total debt	$ 611,537	$ 696,850

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	$ 137,498
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	26,190
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	390,231
June 18, 2009	June 18 and Dec 18	2 equal annual installments June 18, 2020 - 2021	7.97%	US$225,000	US$44,000	57,618
					Total carrying value	$ 611,537

During the three months ended June 30, 2019, Enerplus made its third US$22 million principal repayment on its 2009 senior notes and a $30 million bullet repayment on its 2012 senior notes. During the three months ended June 30, 2018, Enerplus made its second US$22 million principal repayment on its 2009 senior notes.

9) ASSET RETIREMENT OBLIGATION

($ thousands)	Six months ended June 30, 2019	Year ended December 31, 2018
Balance, beginning of year	$ 126,112	$ 117,736
Change in estimates	5,410	16,755
Property acquisitions and development activity	794	1,565
Divestments	(2,242)	(4,585)
Settlements	(5,893)	(11,263)
Accretion expense	2,917	5,904
Balance, end of period	$ 127,098	$ 126,112

Enerplus has estimated the present value of its asset retirement obligation to be $127.1 million at June 30, 2019 based on a total undiscounted liability of $342.0 million (December 31, 2018 – $126.1 million and $343.9 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.55% (December 31, 2018 – 5.59%).

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 includes 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.

	At June 30, 2019
Weighted average remaining lease term (years)	
Operating leases	4.5
Weighted average discount rate	
Operating leases	4.1%

The components of lease expense for the three and six months ended June 30, 2019 are as follows:

($ thousands)	Three months ended June 30, 2019	Six months ended June 30, 2019	Financial Statement Presentation
Operating lease expense(1)	$ 3,879	$ 8,463	PP&E
Operating lease expense(1)	3,588	6,376	Operating expense
Operating lease expense(1)	1,626	3,253	G&A expense
Sublease income	(256)	(500)	G&A expense
Total	$ 8,837	$ 17,592	

(1) Includes short-term and variable lease costs of $4.0 million and $8.4 million for the three and six months ended June 30, 2019, respectively.

Maturities of lease liabilities, all of which are classified as operating leases at June 30, 2019 are as follows:

Maturity of Lease Liabilities

($ thousands)	Operating Leases
2019	$ 9,423
2020	19,331
2021	13,937
2022	7,551
After 2022	16,935
Total lease payments	$ 67,177
Less imputed interest	(6,105)
Total discounted lease payments	$ 61,072
Current portion of lease liabilities	$ 16,974
Non-current portion of lease liabilities	$ 44,098

Supplemental information related to leases are as follows:

($ thousands)	Three months ended June 30, 2019	Six months ended June 30, 2019
Cash amounts paid to settle lease liabilities:		
Operating cash flow used for operating leases	$ 4,758	$ 9,264
Right-of-use assets obtained in exchange for lease obligations:		
Operating leases	$ 1,105	$ 19,967

11) OIL AND NATURAL GAS SALES

($ thousands)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Oil and natural gas sales	$ 403,206	$ 406,823	$ 759,582	$ 735,375
Royalties(1)	(81,743)	(79,439)	(150,667)	(142,971)
Oil and natural gas sales, net of royalties	$ 321,463	$ 327,384	$ 608,915	$ 592,404

(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 and six months ended June 30, 2019 and 2018 are as follows:

Three months ended June 30, 2019 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 47,378	$ 41,386	$ 3,703	$ 1,582	$ 707
United States	274,085	217,830	51,766	4,489	—
Total	$ 321,463	$ 259,216	$ 55,469	$ 6,071	$ 707

Three months ended June 30, 2018 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 56,128	$ 45,023	$ 6,581	$ 3,774	$ 750
United States	271,256	218,039	45,692	7,525	—
Total	$ 327,384	$ 263,062	$ 52,273	$ 11,299	$ 750

Six months ended June 30, 2019 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 100,276	$ 80,805	$ 14,071	$ 4,068	$ 1,332
United States	508,639	375,669	124,922	8,048	—
Total	$ 608,915	$ 456,474	$ 138,993	$ 12,116	$ 1,332

Six months ended June 30, 2018 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 106,903	$ 81,009	$ 16,221	$ 7,833	$ 1,840
United States	485,501	369,262	104,287	11,952	—
Total	$ 592,404	$ 450,271	$ 120,508	$ 19,785	$ 1,840

(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

($ thousands)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
General and administrative expense	$ 11,796	$ 12,131	$ 24,227	$ 25,336
Share-based compensation expense	3,884	5,058	13,163	15,077
General and administrative expense(1)	$ 15,680	$ 17,189	$ 37,390	$ 40,413

(1) Includes cash and non-cash amounts.

13) FOREIGN EXCHANGE

($ thousands)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Realized:				
Foreign exchange (gain)/loss	$ 89	$ 221	$ (29)	$ 289
Translation of U.S. dollar cash held in Canada (gain)/loss	4,158	(3,696)	9,354	(11,042)
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	(16,498)	12,386	(33,602)	30,035
Foreign exchange (gain)/loss	$ (12,251)	$ 8,911	$ (24,277)	$ 19,282

14) INCOME TAXES

($ thousands)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Current tax expense/(recovery)				
Canada	$ (13,941)	$ —	$ (13,941)	$ —
United States	13	72	(5,517)	138
Current tax expense/(recovery)	(13,928)	72	(19,458)	138
Deferred tax expense/(recovery)				
Canada	$ 34,808	$ (20,460)	$ 5,249	$ (25,970)
United States	13,989	23,699	25,680	41,684
Deferred tax expense/(recovery)	48,797	3,239	30,929	15,714
Income tax expense/(recovery)	$ 34,869	$ 3,311	$ 11,471	$ 15,852

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. Our overall net deferred income tax asset was $424.0 million at June 30, 2019 (December 31, 2018 – $465.1 million).

During the three months ended June 30, 2019, Enerplus recorded a deferred tax expense of $26.3 million for the remeasurement of its Canadian net deferred income tax asset for the change in the Alberta corporate tax rate.

During the three months ended June 30, 2019, Enerplus settled an outstanding dispute with the Canadian tax authorities in the Company's favor reducing the balance of its December 31, 2018 unrecognized tax benefit to nil and recorded a current tax recovery of $13.9 million, including tax and interest. During the six months ended June 30, 2019, the current tax recovery included $5.5 million related to the reversal of the reserve recorded at December 31, 2017 for the sequestered portion of the U.S. Alternative Minimum Tax ("AMT") refund.

At June 30, 2019, the current income tax receivable included $27.9 million related to a portion of the U.S. AMT refund (December 31, 2018 – $54.4 million) and $13.9 million related to the settlement of the Company's unrecognized tax benefit.

15) SHAREHOLDERS' EQUITY

a) Share Capital

	Six months ended June 30, 2019		Year ended December 31, 2018	
Authorized unlimited number of common shares issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	239,411	$ 3,337,608	242,129	$ 3,386,946
Issued/(Purchased) for cash:				
Purchase of common shares under Normal Course Issuer Bid	(8,359)	(116,423)	(5,925)	(82,596)
Stock Option Plan	—	—	668	9,138
Non-cash:				
Share-based compensation – settled[(1)]	564	4,406	2,539	23,389
Stock Option Plan – exercised	—	—	—	731
Balance, end of period	231,616	$ 3,225,591	239,411	$ 3,337,608

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

Dividends declared to shareholders for the three and six months ended June 30, 2019 were $7.0 million and $14.2 million, respectively (2018 – $7.3 million and $14.7 million, respectively).

On March 21, 2019, Enerplus renewed its Normal Course Issuer Bid ("NCIB") to continue to repurchase shares through the facilities of the Toronto Stock Exchange, New York Stock Exchange and/or alternative Canadian trading systems. Pursuant to the NCIB renewal, the Company was permitted to repurchase for cancellation up to 16,673,015 common shares over a period of twelve months commencing on March 26, 2019. All repurchases are 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 is allocated to accumulated deficit.

During the three months ended June 30, 2019, the Company repurchased 6,626,783 common shares under the current NCIB at an average price of $10.64 per share, for total consideration of $70.6 million. Of the amount paid, $92.3 million was charged to share capital and $21.7 million was credited to accumulated deficit. During the six months ended June 30, 2019, the Company repurchased 8,358,821 common shares under the previous and current NCIB at an average price of $10.80 per share, for total consideration of $90.4 million. Of the amount paid, $116.4 million was charged to share capital and $26.0 million was credited to accumulated deficit.

Subsequent to the quarter, and up to August 7, 2019, the Company repurchased an additional 981,266 common shares under the NCIB at an average price of $8.97 per share, for total consideration of $8.8 million.

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):

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2019	2018	2019	2018
Cash:				
Long-term incentive plans (recovery)/expense	$ (626)	$ 435	$ 711	$ 2,381
Non-cash:				
Long-term incentive plans	4,263	4,997	12,306	14,076
Equity swap (gain)/loss	247	(374)	146	(1,380)
Share-based compensation expense	$ 3,884	$ 5,058	$ 13,163	$ 15,077

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

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Deferred Share Unit ("DSU") plan activity for the six months ended June 30, 2019:

For the six months ended June 30, 2019	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	DSU(1)	PSU(2)	RSU	
Balance, beginning of year	391	1,371	1,753	3,515
Granted	97	803	845	1,745
Vested	(68)	—	(1,007)	(1,075)
Forfeited	—	(49)	(38)	(87)
Balance, end of period	420	2,125	1,553	4,098

(1) Settlement of units vested has been deferred.
(2) Based on underlying awards before any effect of the performance multiplier.

Cash-settled LTI Plans

For the three and six months ended June 30, 2019, the Company recorded a cash share-based compensation recovery of $0.6 million and expense of $0.7 million, respectively (June 30, 2018 – expense of $0.4 million and $2.4 million, respectively). For the three and six months ended June 30, 2019, the Company made cash payments of $0.1 million related to its cash-settled plans (June 30, 2018 – $0.4 million).

As of June 30, 2019, a liability of $4.8 million (December 31, 2018 – $4.1 million) with respect to the DSU plan 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 June 30, 2019 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 24,664	$ 9,581	$ 34,245
Unrecognized share-based compensation expense	15,601	9,895	25,496
Fair value	$ 40,265	$ 19,476	$ 59,741
Weighted-average remaining contractual term (years)	1.9	1.6	

(1) Includes estimated performance multipliers.

The 2016 PSU's which vested and were recognized in December 2018 were cash settled in January 2019.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the six months ended June 30, 2019, $5.0 million (2018 – nil) in cash withholding taxes were paid.

ii) Stock Option Plan

At June 30, 2019 all stock options are fully vested and any related non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the six months ended June 30, 2019:

Period ended June 30, 2019	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	4,131	$ 17.12
Forfeited	(42)	16.74
Expired	(1,436)	22.79
Options outstanding, end of period	2,653	$ 14.05
Options exercisable, end of period	2,653	$ 14.05

At June 30, 2019, Enerplus had 2,652,774 options that were exercisable at a weighted average exercise price of $14.05 with a weighted average remaining contractual term of 0.6 years, giving an aggregate intrinsic value of nil (June 30, 2018 – 1.3 years and $8.0 million). The intrinsic value of options exercised for the three and six months ended June 30, 2019 was nil and nil, respectively (June 30, 2018 – $0.5 million and $0.7 million, respectively).

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

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

	Three months ended June 30,		**Six months ended June 30,**	
(thousands, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Net income/(loss)	$ 85,084	$ 12,404	$ 104,242	$ 42,041
Weighted average shares outstanding – Basic	235,490	244,862	237,197	244,369
Dilutive impact of share-based compensation	2,699	5,260	2,750	4,998
Weighted average shares outstanding – Diluted	238,189	250,122	239,947	249,367
Net income/(loss) per share				
Basic	$ 0.36	$ 0.05	$ 0.44	$ 0.17
Diluted	$ 0.36	$ 0.05	$ 0.43	$ 0.17

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 30, 2019, 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 June 30, 2019, the senior notes had a carrying value of $611.5 million and a fair value of $620.7 million (December 31, 2018 – $696.9 million and $695.4 million, respectively).

The fair value of derivative contracts and the senior notes are considered a level 2 fair value measurement. 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 and six months ended June 30, 2019 and 2018:

Gain/(Loss) ($ thousands)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018	Income Statement Presentation
Electricity Swaps	$ —	$ 78	$ —	$ 62	Operating expense
Equity Swaps	(247)	374	(146)	1,380	G&A expense
Commodity Derivative Instruments:					
Oil	23,617	(70,905)	(63,312)	(100,760)	Commodity derivative instruments
Gas	4,983	(760)	(3,517)	(1,517)	
Total	$ 28,353	$ (71,213)	$ (66,975)	$ (100,835)	

The following table summarizes the income statement effects of Enerplus' commodity derivative instruments:

($ thousands)	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Change in fair value gain/(loss)	$ 28,600	$ (71,665)	$ (66,829)	$ (102,277)
Net realized cash gain/(loss)	(1,178)	(19,286)	9,384	(9,138)
Commodity derivative instruments gain/(loss)	$ 27,422	$ (90,951)	$ (57,445)	$ (111,415)

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

	June 30, 2019			December 31, 2018		
	Assets		Liabilities	Assets		Liabilities
($ thousands)	Current	Long-term	Current	Current	Long Term	Current
Equity Swaps	$ —	$ —	$ 2,055	$ —	$ —	$ 1,909
Commodity Derivative Instruments:						
Oil	13,920	3,408	106	48,314	32,220	—
Gas	7,427	—	—	10,944	—	—
Total	$ 21,347	$ 3,408	$ 2,161	$ 59,258	$ 32,220	$ 1,909

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 derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize the Corporation's price risk management positions at August 7, 2019:

Crude Oil Instruments:

Instrument Type[(1)(2)]	bbls/day	US$/bbl
Jul 1, 2019 – Sep 30, 2019		
WTI Purchased Put	24,500	54.81
WTI Sold Call	24,500	65.95
WTI Sold Put	24,500	44.64
WCS Differential Swap	1,500	(14.83)
WTI – Brent Swap	2,700	(8.10)
Aug 1, 2019 – Aug 31, 2019		
UHC Differential Swap	2,000	(0.10)
Oct 1, 2019 – Dec 31, 2019		
WTI Purchased Put	24,500	54.81
WTI Sold Call	24,500	65.99
WTI Sold Put	24,500	44.64
WCS Differential Swap	1,500	(14.83)
WTI – Brent Swap	2,700	(8.10)

Jan 1, 2020 – Dec 31, 2020		
WTI Purchased Put	16,000	57.50
WTI Sold Put	16,000	46.88
WTI – Brent Swap	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$2.00/bbl from July 1, 2019 to December 31, 2020.

For the remainder of 2019, Enerplus has physical sales contracts in place for approximately 26,300 bbls/day of Bakken production with fixed differentials averaging approximately US$2.66/bbl below WTI, a portion of which is sold directly into the U.S. Gulf Coast that utilizes the Company's firm capacity on the Dakota Access Pipeline.

Natural Gas Instruments:

Instrument Type(1)	MMcf/day	US$/Mcf
Jul 1, 2019 – Jul 31, 2019		
NYMEX Swap (Sale)	90.0	2.85
NYMEX Swap (Purchase)	60.0	2.34
Aug 1, 2019 – Oct 31, 2019		
NYMEX Swap (Sale)	90.0	2.85
NYMEX Swap (Purchase)	90.0	2.34

(1) Transactions with a common term have been aggregated and presented at a weighted average price/Mcf.

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 June 30, 2019, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At June 30, 2019, 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 between 2019 and 2020 that effectively fix the future settlement cost on 264,000 shares at a weighted average price of $17.82 per share.

ii) Credit Risk

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At June 30, 2019, 86% 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. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at June 30, 2019 was $3.8 million (December 31, 2018 – $3.9 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 June 30, 2019, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

17) COMMITMENTS AND CONTINGENCIES

As of the date of this report, other than changes related to the adoption of the new lease accounting standard as described in Note 3, 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, 2018.

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 June 30,		Six months ended June 30,	
($ thousands)	2019	2018	2019	2018
Accounts receivable	$ 37,580	$ (44,863)	$ 23,401	$ (51,500)
Other assets	4,891	1,539	1,864	3,160
Accounts payable	8,985	13,436	(28,223)	25,921
	$ 51,456	$ (29,888)	$ (2,958)	$ (22,419)

b) Changes in Other Non-Cash Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2019	2018	2019	2018
Non-cash financing activities(1)	$ (65)	$ 3	$ (77)	$ 29
Non-cash investing activities(2)	41,039	31,463	91,140	76,123

(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 June 30,		Six months ended June 30,	
($ thousands)	2019	2018	2019	2018
Income taxes paid/(received)	$ (57,663)	$ 2	$ (57,599)	$ (83)
Interest paid	14,390	14,937	17,649	18,193

BOARD OF DIRECTORS

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Corporate Director
Boerne, Texas

Karen E. Clarke-Whistler[3][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

Hilary A. Foulkes[4][7][9][11]
Corporate Director
Calgary, Alberta

Robert B. Hodgins[3][6][9]
Corporate Director
Calgary, Alberta

Susan M. MacKenzie[5][7][12]
Corporate Director
Calgary, Alberta

Jeffrey W. Sheets[5][9][11]
Corporate Director
Houston, Texas

Sheldon B. Steeves[8][11]
Corporate Director
Calgary, Alberta

(1) Chairman 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

Raymond J. Daniels
Senior Vice President, Operations, People & Culture

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

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Calgary, Alberta

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KPMG LLP
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TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
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U.S. CO-TRANSFER AGENT

Computershare Trust Company, N.A.
Golden, Colorado

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McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto 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

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