enerPLUS

2018

financial summary

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2018 FINANCIAL SUMMARY

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Financial (000's)				
Net Income	$ 249,315	$ 15,272	$ 378,279	$ 236,998
Cash Flow from Operating Activities	221,619	135,332	738,784	476,125
Adjusted Funds Flow(4)	214,285	199,559	753,506	524,064
Dividends to Shareholders - Declared	7,234	7,264	29,256	29,033
Total Debt Net of Cash(4)	333,523	325,831	333,523	325,831
Capital Spending	72,058	116,827	593,876	458,015
Property and Land Acquisitions	9,474	3,805	25,840	13,276
Property Divestments	886	(1,385)	6,912	56,196
Net Debt to Adjusted Funds Flow Ratio(4)	0.4x	0.6x	0.4x	0.6x
Financial per Weighted Average Shares Outstanding				
Net Income - Basic	$ 1.03	$ 0.06	$ 1.55	$ 0.98
Net Income - Diluted	1.02	0.06	1.53	0.96
Weighted Average Number of Shares Outstanding (000's) - Basic	242,344	242,129	244,076	241,929
Weighted Average Number of Shares Outstanding (000's) - Diluted	245,242	248,122	247,261	247,874
Selected Financial Results per BOE(1)(2)				
Oil & Natural Gas Sales(3)	$ 45.43	$ 41.72	$ 47.35	$ 36.93
Royalties and Production Taxes	(11.58)	(10.65)	(11.92)	(8.91)
Commodity Derivative Instruments	(0.31)	(0.39)	(1.05)	0.28
Cash Operating Expenses	(6.99)	(6.42)	(7.00)	(6.39)
Transportation Costs	(3.71)	(3.20)	(3.63)	(3.60)
General and Administrative Expenses	(1.40)	(1.55)	(1.47)	(1.63)
Cash Share-Based Compensation	0.23	(0.01)	(0.01)	(0.03)
Interest, Foreign Exchange and Other Expenses	(0.90)	(1.17)	(0.92)	(1.24)
Current Income Tax Recovery	3.03	6.15	0.80	1.55
Adjusted Funds Flow(4)	$ 23.80	$ 24.48	$ 22.15	$ 16.96

SELECTED OPERATING RESULTS	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Average Daily Production(2)				
Crude Oil (bbls/day)	49,968	42,374	45,424	36,935
Natural Gas Liquids (bbls/day)	4,483	4,448	4,486	3,858
Natural Gas (Mcf/day)	260,453	250,607	259,837	263,506
Total (BOE/day)	97,860	88,590	93,216	84,711
% Crude Oil and Natural Gas Liquids	56%	53%	54%	48%
Average Selling Price(2)(3)				
Crude Oil (per bbl)	$ 64.18	$ 65.91	$ 74.59	$ 58.69
Natural Gas Liquids (per bbl)	26.72	32.26	28.31	30.01
Natural Gas (per Mcf)	4.28	3.03	3.42	3.21
Net Wells Drilled	12	7	61	46

(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 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 December 31, 2018	2017	Twelve months ended December 31, 2018	2017
WTI crude oil (US$/bbl)	$ 58.81	$ 55.40	$ 64.77	$ 50.95
Brent (ICE) crude oil (US$/bbl)	68.08	61.54	71.53	54.83
NYMEX natural gas – last day (US$/Mcf)	3.64	2.93	3.09	3.11
AECO natural gas – monthly index (CDN$/Mcf)	1.90	1.96	1.53	2.43
US/CDN average exchange rate	1.32	1.27	1.30	1.30

Share Trading Summary For the twelve months ended December 31, 2018	CDN[1] – ERF (CDN$)	U.S.[2] – ERF (US$)
High	$ 18.04	$ 13.87
Low	$ 9.65	$ 6.84
Close	$ 10.62	$ 7.76

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

2018 Dividends per Share	CDN$	US$[1]
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.12	$ 0.08

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

2018 HIGHLIGHTS

Financial and Operational Highlights

- Fourth quarter 2018 production was at the high-end of the Company's guidance range and modestly higher than the prior quarter. Total fourth quarter production averaged 97,860 BOE per day, including oil and natural gas liquids production of 54,451 barrels per day (92% oil).
- Full year 2018 production was also at the high-end of the Company's guidance range, averaging 93,216 BOE per day, including 49,910 barrels per day of crude oil and natural gas liquids (91% oil). Year-over-year, the Company's 2018 production increased by 10%, with liquids production increasing by 22%. This growth was largely driven by North Dakota production which increased by 42%.
- Higher realized commodity prices and increased production volumes resulted in significant increases to cash flow from operating activities and adjusted funds flow for 2018 compared to 2017.
    - Fourth quarter cash flow from operating activities increased to $221.6 million from $216.1 million in the third quarter. Full year 2018 cash flow from operating activities was $738.8 million, 55% higher than 2017.
    - Fourth quarter adjusted funds flow increased to $214.3 million from $210.4 million in the third quarter. Fourth quarter adjusted funds flow benefited from a $27.2 million Alternative Minimum Tax ("AMT") refund expected to be realized in 2019. Enerplus expects to realize the remaining $27.2 million in AMT refund in 2020 and 2021. Full year 2018 adjusted funds flow was $753.5 million, 44% higher than 2017.
- Fourth quarter net income was $249.3 million ($1.03 per share) compared to $86.9 million ($0.35 per share) in the prior quarter. Full year 2018 net income was $378.3 million ($1.55 per share) compared to $237.0 million ($0.98 per share) in 2017.
- Fourth quarter adjusted net income was $102.2 million ($0.42 per share) compared to $97.3 million ($0.40 per share) in the prior quarter. Full year 2018 adjusted net income was $344.8 million ($1.41 per share) compared to $132.2 million ($0.55 per share) in 2017.
- Capital spending was $72.1 million in the fourth quarter of 2018, bringing full year 2018 capital spending to $593.9 million, in-line with the Company's $585 million 2018 budget.
- Enerplus remains in a strong financial position. The Company's net debt at December 31, 2018 was $333.5 million, comprised of $696.8 million of senior notes less $363.3 million in cash. At December 31, 2018, Enerplus was undrawn on its $800 million bank credit facility and had a net debt to adjusted funds flow ratio of 0.4 times.
- During 2018 Enerplus repurchased 5,925,084 common shares at an average share price of $13.33 and a cost of $79.0 million.

Reserves Highlights

- Replaced 194% of 2018 production, adding 65.7 MMBOE (51% oil) of 2P reserves from development activities (including revisions and economic factors).
- Material reserves growth was realized in North Dakota and the Marcellus. The Company replaced 244% of 2018 North Dakota production, adding 35.1 MMBOE of 2P reserves and 247% of 2018 Marcellus production, adding 187.4 Bcf of 2P reserves (including revisions and economic factors).
- Finding and development ("F&D") costs were $13.08 per BOE for proved developed producing ("PDP") reserves, $16.69 per BOE for proved reserves, and $13.74 per BOE for 2P reserves, including future development costs ("FDC").
- Three-year average F&D costs were $10.17 per BOE for PDP reserves, $10.27 per BOE for proved reserves, and $10.04 per BOE for 2P reserves, including FDC.
- Finding, development and acquisition ("FD&A") costs were $17.42 per BOE for proved reserves and $14.37 per BOE for 2P reserves, including FDC.
- Three-year average FD&A costs were $7.55 per BOE for proved reserves and $8.26 per BOE for 2P reserves, including FDC.
- Total 2P reserves were 427.7 MMBOE at year-end 2018, representing an 8% increase from year-end 2017.
- 2P reserves were comprised of 49% crude oil, 5% natural gas liquids, and 46% natural gas at year-end 2018.
- Proved developed producing reserves and total proved reserves represent 46% and 70% of 2P reserves, respectively.

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

The following discussion and analysis of financial results is dated February 21, 2019 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016.

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

BASIS OF PRESENTATION

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

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, 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. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101–Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities. All reserves information presented herein has been prepared in accordance with NI 51-101 and is presented at December 31, 2018 unless otherwise stated.

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

The following table provides a reconciliation of our production volumes:

	Year ended December 31,		
Average Daily Production Volumes	**2018**	**2017**	**2016**
Company interest production volumes			
Crude oil (bbls/day)	45,424	36,935	38,353
Natural gas liquids (bbls/day)	4,486	3,858	4,903
Natural gas (Mcf/day)	259,837	263,506	299,214
Company interest production volumes (BOE/day)	93,216	84,711	93,125
Royalty volumes			
Crude oil (bbls/day)	9,054	7,531	7,198
Natural gas liquids (bbls/day)	951	777	932
Natural gas (Mcf/day)	48,923	47,722	50,270
Royalty volumes (BOE/day)	18,159	16,262	16,508
Net production volumes			
Crude oil (bbls/day)	36,370	29,404	31,155
Natural gas liquids (bbls/day)	3,535	3,081	3,971
Natural gas (Mcf/day)	210,914	215,784	248,944
Net production volumes (BOE/day)	75,057	68,449	76,617

2018 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 97,860 BOE/day, which was higher than our third quarter production of 96,861 BOE/day. Crude oil and natural gas liquids production increased by 2% to 54,451 bbls/day compared to the third quarter and was at the high end of our fourth quarter liquids production guidance range of 53,500 – 54,500 bbls/day. Our fourth quarter capital spending of $72.1 million was largely focused on drilling in North Dakota in preparation for the 2019 capital program.

We reported net income of $249.3 million in the fourth quarter compared to net income of $86.9 million in the third quarter. The increase is primarily the result of a $253.7 million gain on commodity derivative instruments compared to a $54.1 million loss in the third quarter of 2018 due to crude oil prices falling below the swap and purchased put levels on our three-way collars.

Fourth quarter cash flow from operating activities and adjusted funds flow increased to $221.6 million and $214.3 million, respectively, from $216.1 million and $210.4 million, respectively, in the third quarter. The increases were due to higher realized natural gas prices in the Marcellus, offset by a decrease in crude oil revenue. Adjusted funds flow in the fourth quarter benefited from a $27.2 million Alternative Minimum Tax ("AMT") refund, expected to be realized in 2019.

During the fourth quarter, we had $142.2 million in free cash flow, enabling our repurchase of 5.4 million common shares for $70.6 million, bringing total repurchases in 2018 to $79.0 million (5.9 million shares), and further enhancing our per share growth and the return of capital to shareholders.

Selected Fourth Quarter Canadian and U.S. Financial Results

	Three months ended December 31, 2018			Three months ended December 31, 2017		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	9,237	40,731	49,968	9,478	32,896	42,374
Natural gas liquids (bbls/day)	956	3,527	4,483	1,198	3,250	4,448
Natural gas (Mcf/day)	23,357	237,096	260,453	37,265	213,342	250,607
Total average daily production (BOE/day)	14,086	83,774	97,860	16,887	71,703	88,590
Pricing[2]						
Crude oil (per bbl)	$ 33.76	$ 71.07	$ 64.18	$ 57.05	$ 68.46	$ 65.91
Natural gas liquids (per bbl)	39.69	23.20	26.72	44.07	27.91	32.26
Natural gas (per Mcf)	3.74	4.33	4.28	3.01	3.04	3.03
Capital Expenditures						
Capital spending	$ 13.5	$ 58.6	$ 72.1	$ 10.9	$ 105.9	$ 116.8
Acquisitions	1.2	8.3	9.5	1.1	2.7	3.8
Divestments	0.9	(1.8)	(0.9)	0.9	0.5	1.4
Netback[3] Before Hedging						
Oil and natural gas sales	$ 40.9	$ 368.3	$ 409.2	$ 64.9	$ 275.2	$ 340.1
Royalties	(5.4)	(77.0)	(82.4)	(13.9)	(55.1)	(69.0)
Production taxes	(0.4)	(21.5)	(21.9)	(0.7)	(17.1)	(17.8)
Cash operating expenses	(17.8)	(45.1)	(62.9)	(18.2)	(34.1)	(52.3)
Transportation costs	(2.6)	(30.8)	(33.4)	(2.9)	(23.3)	(26.2)
Netback before hedging	$ 14.7	$ 193.9	$ 208.6	$ 29.2	$ 145.6	$ 174.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (253.7)	$ —	$ (253.7)	$ 41.0	$ —	$ 41.0
General and administrative expense[4]	11.6	7.5	19.1	13.9	5.8	19.7
Current income tax recovery	—	(27.4)	(27.4)	—	(50.2)	(50.2)

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

Comparing the fourth quarter of 2018 with the same period in 2017:

- Average daily production was 97,860 BOE/day, an increase of 10% from 88,590 BOE/day, primarily due to a 24% increase in U.S. crude oil production as a result of strong well performance and a larger capital spending program in North Dakota in 2018.

- Our crude oil and natural gas liquids production accounted for 56% of our total production mix in the fourth quarter of 2018, an increase from 53% in 2017.

- Capital spending decreased to $72.1 million compared to $116.8 million in the fourth quarter of 2017 due to the timing of our 2018 capital program and limited completions activity in the fourth quarter. The majority of our capital investment in the fourth quarter was focused on drilling our U.S. crude oil properties, with spending of $51.7 million.

- Operating expenses increased to $62.9 million ($6.99/BOE) compared to $52.1 million ($6.39/BOE) in the fourth quarter of 2017 as a result of an increased weighting of crude oil and liquids production with higher associated operating cost metrics.

- Cash general and administrative ("G&A") expenses were unchanged but improved on a per BOE basis from $12.6 million ($1.40/BOE) compared to $12.6 million ($1.55/BOE) in 2017 with increased production volumes.

- During the fourth quarter of 2018, our Bakken crude oil price differential widened to US$5.60/bbl below WTI compared to US$1.61/bbl below WTI for the same period in 2017, as a result of significant refinery maintenance reducing demand in the region. Our Marcellus natural gas differential narrowed in the fourth quarter to US$0.34/Mcf below NYMEX compared to US$0.81/Mcf below NYMEX in 2017, due to additional pipeline capacity that came online during the year.

- We reported net income of $249.3 million in the fourth quarter of 2018 compared to net income of $15.3 million in the fourth quarter of 2017. Net income increased by $234.0 million primarily due to a $253.7 million gain on commodity derivative instruments in 2018 compared to a $41.0 million loss recorded in 2017.

- Cash flow from operating activities and adjusted funds flow increased to $221.6 million and $214.3 million, respectively, compared to $135.3 million and $199.6 million, respectively, in the fourth quarter of 2017. The increases were the result of higher production and stronger natural gas prices in the Marcellus offset by wider Bakken crude oil differentials in the fourth quarter of 2018.

- During the fourth quarter of 2018, we repurchased 5.4 million common shares under our Normal Course Issuer Bid ("NCIB") for total consideration of $70.6 million, bringing our total repurchases to 5.9 million shares for total consideration of $79.0 million in 2018.

- Net debt to adjusted funds flow improved to 0.4x compared to 0.6x in the fourth quarter of 2017.

2018 OVERVIEW AND 2019 OUTLOOK

Summary of Guidance and Results	**Revised 2018 Guidance**	**2018 Results**	**2019 Guidance**
Capital spending ($ millions)	$585	$594	$565 - $635
Average annual production (BOE/day)	92,500 - 93,000	93,216	94,000 – 100,000
Average annual crude oil and natural gas liquids production (bbls/day)	49,500 - 50,000	49,910	52,500 – 56,000
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	53,500 - 54,500	54,451	
Average royalty and production tax rate (% of gross sales, before transportation)	25%	25%	25%
Operating expenses (per BOE)	$7.00	$7.00	$8.00
Transportation costs (per BOE)	$3.60	$3.63	$4.00
Cash G&A expenses (per BOE)	$1.50	$1.47	$1.50

2019 Differential/Basis Outlook and Results(1)			
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.80)/bbl	US$(3.78)/bbl	US$(4.00)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	US$(0.40)/Mcf	US$(0.43)/Mcf	US$(0.30)/Mcf

(1) Excludes transportation costs

2018 Overview

In 2018, we continued to focus on maximizing returns, sustainable growth, as well as returning capital to our shareholders. We delivered total production growth of 10% and liquids growth of 22% compared to 2017 and returned $108.3 million of capital to our shareholders through share repurchases and dividends, while maintaining our balance sheet strength.

In 2018, our annual average production was 93,216 BOE/day with crude oil and liquids volumes of 49,910 bbls/day, at the high end of our revised production guidance targets of 92,500 – 93,000 BOE/day and 49,500 – 50,000 bbls/day, respectively. Our capital spending for the year totaled $593.9 million, in line with our guidance of $585 million. The majority of our spending (88%) was focused on our liquids properties, primarily in North Dakota.

Our Bakken sales price differentials remained consistent with the prior year averaging US$3.78/bbl below WTI, which was in line with our revised guidance of US$3.80/bbl below WTI. Our Marcellus differential narrowed to US$0.43/Mcf below NYMEX, a 43% improvement compared to 2017, due to additional pipeline capacity coming into service. Canadian crude oil and natural gas differentials weakened significantly in 2018, averaging US$21.83/bbl below WTI and US$0.81/Mcf below NYMEX, respectively, mainly due to limited pipeline takeaway capacity and storage concerns.

Operating expenses and cash G&A expenses were $7.00/BOE and $1.47/BOE, respectively, consistent with our guidance of $7.00/BOE and $1.50/BOE, respectively.

Net income for 2018 was $378.3 million, an increase from $237.0 million in 2017 primarily due to higher revenue as a result of an increase in production, realized pricing and gains on commodity derivative instruments. The higher production also increased operating, royalty and depletion expenses, which partially offset the higher revenue in 2018 when compared to 2017.

Cash flow from operations and adjusted funds flow increased significantly to $738.8 million and $753.5 million, respectively, from $476.1 million and $524.1 million, respectively, in 2017. Oil and natural gas sales increased by $469.1 million, compared to 2017, largely due to higher realized commodity prices, narrower sales price differentials in the Marcellus and higher production volumes. This increase was partially offset by higher operating and royalty expenses in 2018.

Total debt net of cash at December 31, 2018 was $333.5 million, comprised of $696.8 million of senior notes less $363.3 million in cash. At December 31, 2018, we were undrawn on our $800 million senior unsecured bank credit facility and had a net debt to adjusted funds flow ratio of 0.4x.

2019 Outlook

Our focus in 2019 is to continue to maximize returns, while delivering sustainable liquids production growth, returning capital to shareholders and preserving our balance sheet strength. Our capital budget range for 2019 is between $565 million and $635 million, with the majority of capital being allocated to our North Dakota crude oil properties. As a result, we expect annual liquids production growth of approximately 9% at the mid-point of production guidance in 2019.

Annual 2019 production is expected to average between 94,000 – 100,000 BOE/day, with crude oil and natural gas liquids production expected to average between 52,500 – 56,000 bbls/day. As a result of lower capital spending in the fourth quarter of 2018, we expect the majority of our production growth to occur during the second half of 2019.

We expect our Bakken sales price differential to widen slightly in 2019 to be approximately US$4.00/bbl below WTI, which includes 16,000 bbls/day of fixed price differential sales at approximately US$3.00/bbl below WTI. In the Marcellus, we expect our sales price differential to improve to approximately US$0.30/Mcf below NYMEX as a result of excess pipeline egress out of the region.

To support our 2019 capital program, we have hedged 63% of our 2019 forecasted crude oil production, after royalties, primarily through the use of three-way collar structures. We also have additional natural gas hedges in 2019 for approximately 34% of our forecasted 2019 natural gas production, after royalties.

Operating expenses are expected to average approximately $8.00/BOE in 2019, an increase from 2018, as a result of the increase to our crude oil and liquids weighting throughout 2019, as well as an increase in gas processing costs and the use of electrical submersible pumps in North Dakota. We continue to focus our capital program on crude oil production growth, which has higher operating cost metrics.

We expect cash G&A expenses and transportation costs for 2019 to average approximately $1.50/BOE and $4.00/BOE, respectively. The increase in transportation costs reflects additional transportation commitments that provide access to sell a portion of our production at U.S. gulf coast or Brent pricing.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2018	2017	2016
Crude oil (bbls/day)	45,424	36,935	38,353
Natural gas liquids (bbls/day)	4,486	3,858	4,903
Natural gas (Mcf/day)	259,837	263,506	299,214
Total daily sales (BOE/day)	93,216	84,711	93,125

Production in 2018 averaged 93,216 BOE/day, in line with our revised guidance range of 92,500 – 93,000 BOE/day and a 10% increase when compared to 2017. Crude oil and liquids production averaged 49,910 BOE/day, meeting our revised guidance of 49,500 – 50,000 bbls/day, as a result of a successful capital program focused on our U.S. crude oil properties.

Our U.S. production volumes increased by 20% to 78,287 BOE/day compared to 2017, mainly due to a 10,743 bbl/day increase in crude oil and natural gas liquids production as a result of strong well performance in North Dakota and an increase to our 2018 capital spending program. Our U.S. natural gas production increased by 7% with no price related curtailments in the Marcellus during the year.

Canadian production volumes decreased by 4,748 BOE/day or 24% compared to the prior year, largely due to the full year impact of non-core asset divestments that occurred throughout 2017.

Our crude oil and natural gas liquids production accounted for 54% of our total average daily production in 2018, a significant increase when compared to 48% in 2017 and 46% in 2016.

Production for 2017 compared to 2016 decreased 9% or 8,414 bbls/day. The decrease was primarily a result of non-core Canadian divestments throughout 2017 and the sale of our U.S. non-operated North Dakota properties, which closed on December 30, 2016. The impact of divestments was somewhat offset by growth in our operated U.S. crude oil production with the additional capital spending on our North Dakota assets.

2019 Guidance

We expect annual average production for 2019 of 94,000 – 100,000 BOE/day, including 52,500 – 56,000 bbls/day of crude oil and natural gas liquids, resulting in year over year production growth of 4% and liquids production growth of 9% based on a WTI price of US$50/bbl – US$55/bbl.

Pricing

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

Pricing (average for the period)	2018	2017	2016
Benchmarks			
WTI crude oil (US$/bbl)	$ 64.77	$ 50.95	$ 43.32
Brent (ICE) crude oil (US$/bbl)	71.53	54.83	45.04
NYMEX natural gas – last day (US$/Mcf)	3.09	3.11	2.46
AECO natural gas – monthly index ($/Mcf)	1.53	2.43	2.09
US/CDN average exchange rate	1.30	1.30	1.32
US/CDN period end exchange rate	1.36	1.26	1.34
Enerplus selling price(1)			
Crude oil ($/bbl)	$ 74.59	$ 58.69	$ 44.84
Natural gas liquids ($/bbl)	28.31	30.01	15.29
Natural gas ($/Mcf)	3.42	3.21	2.06
Average benchmark differentials			
Brent (ICE) - WTI (US$/bbl)	$ 6.77	$ 3.88	$ 1.72
MSW Edmonton – WTI (US$/bbl)	(11.12)	(2.46)	(3.21)
WCS Hardisty – WTI (US$/bbl)	(26.31)	(11.98)	(13.84)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.64)	(0.96)	(1.15)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.73)	(1.03)	(1.21)
AECO monthly – NYMEX (US$/Mcf)	(1.90)	(1.26)	(0.89)

Enerplus realized differentials(1)(2)			
Bakken crude oil – WTI (US$/bbl)	$ (3.78)	$ (3.72)	$ (7.46)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.43)	(0.76)	(0.93)
Canada crude oil – WTI (US$/bbl)	(21.83)	(10.94)	(13.21)
Canada natural gas – NYMEX (US$/Mcf)	(0.81)	(0.62)	(0.80)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Benchmark WTI prices increased by 27% to US$64.77/bbl in 2018 compared to 2017, largely due to lower global inventories as a result of the supply reductions made by the Organization of Petroleum Exporting Countries ("OPEC"). In addition, supply concerns, particularly in Venezuela, and the reimposition of U.S. sanctions on Iran supported global crude oil prices for the majority of the year. However, WTI prices declined significantly during the fourth quarter of 2018, closing at US$45.41/bbl. The decline in oil prices was due to concerns over global trade and ongoing geopolitical issues, which may reduce global demand. Our 2018 realized crude oil price averaged $74.59/bbl, a 27% increase compared to 2017, in line with changes in the underlying benchmark price.

Our Bakken sales price differentials weakened slightly in 2018 compared to the prior year, averaging US$3.78/bbl below WTI, which was in line with our revised guidance of US$3.80/bbl below WTI. Bakken prices were strong during the second and third quarter of 2018 but weakened significantly during the fourth quarter. This was due to a large amount of demand lost during seasonal refinery maintenance and higher than anticipated production increases that put pressure on regional pipeline capacity. Our realized Bakken differentials were somewhat insulated from the weakness in the fourth quarter of 2018 due to a portion of our physical sales being based on term negotiated fixed differentials to WTI. We expect Bakken differentials to widen slightly in 2019 and are guiding to US$4.00/bbl below WTI, which includes 16,000 bbls/day of fixed price differential sales at approximately US$3.00/bbl below WTI.

Canadian crude oil differentials weakened substantially in 2018, with both heavy and light differentials trading at much wider levels compared to the prior year. This was especially evident during the fourth quarter of 2018, as pipeline capacity leaving the region was fully utilized, resulting in a large increase in Canadian crude oil held in storage and a significant volume of production using rail to clear the region. However, differentials have recently strengthened due to Alberta government mandated production curtailments, which were announced in December 2018. Inadequate pipeline takeaway continues to be a major concern throughout the Canadian oil and gas industry.

We realized an average price of $28.31/bbl on our natural gas liquids production in 2018, which represents a 6% decrease in prices when compared to 2017. This decrease was mainly due to lower condensate prices in both Canada and the U.S.

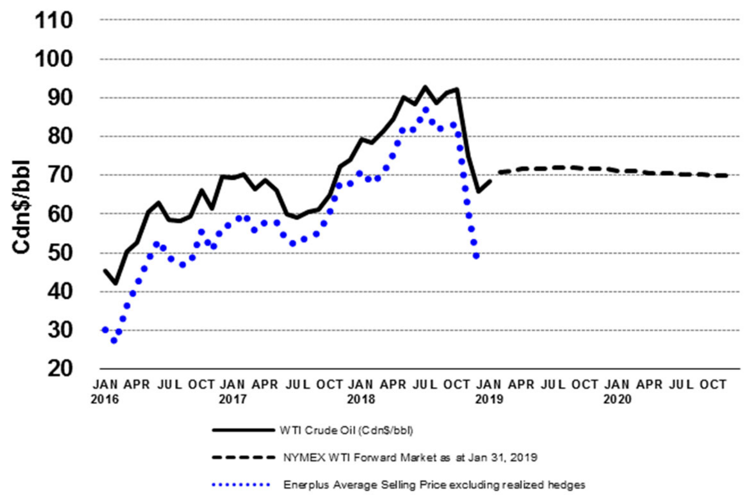
NATURAL GAS

Our realized natural gas price averaged $3.42/Mcf in 2018, a 7% increase from 2017 realized prices, despite NYMEX and AECO prices both declining on a year-over-year basis. Our realized natural gas price outperformed the benchmarks due to stronger Marcellus basis differentials in 2018 and the positive impact of our multi-year term AECO physical sales which had average fixed basis differentials of US$0.64/Mcf below NYMEX.

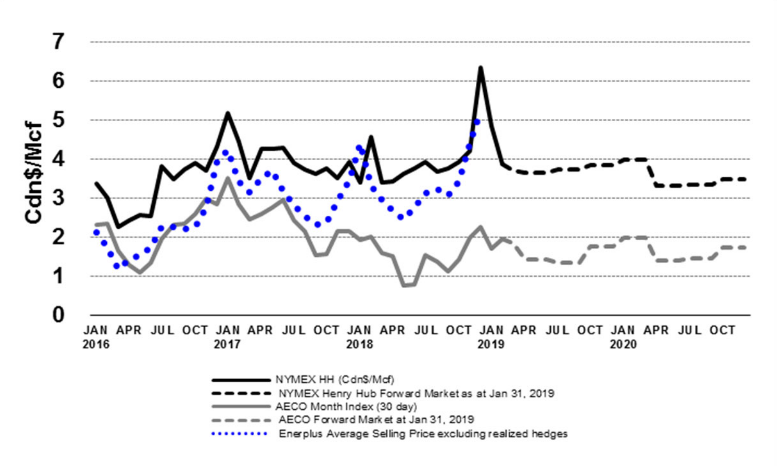
In the Marcellus, the Tennessee Gas Pipeline Zone 4 - 300 Leg and Transco Leidy monthly benchmark differentials averaged US$0.73/Mcf and US$0.64/Mcf below NYMEX, respectively, compared to US$1.03/Mcf and US$0.96/Mcf, respectively, below NYMEX in 2017. The strengthening in local Marcellus prices was due to additional pipeline capacity coming into service, as well as stronger weather-related demand in the region. As a result, our realized portfolio sales price differential, before transportation costs, averaged US$0.43/Mcf below NYMEX for the year, which was in line with our guidance of US$0.40/Mcf below NYMEX. We expect our Marcellus differential to average US$0.30/Mcf below NYMEX in 2019 as regional prices continue to benefit from excess pipeline takeaway capacity.

In Alberta, congestion on regional and export pipelines and continued production growth resulted in benchmark AECO monthly prices averaging US$1.90/Mcf below NYMEX in 2018 compared to US$1.26/Mcf below NYMEX in 2017. We continue to benefit from our term AECO physical sales.

Monthly Crude Oil Prices



Monthly Natural Gas Prices

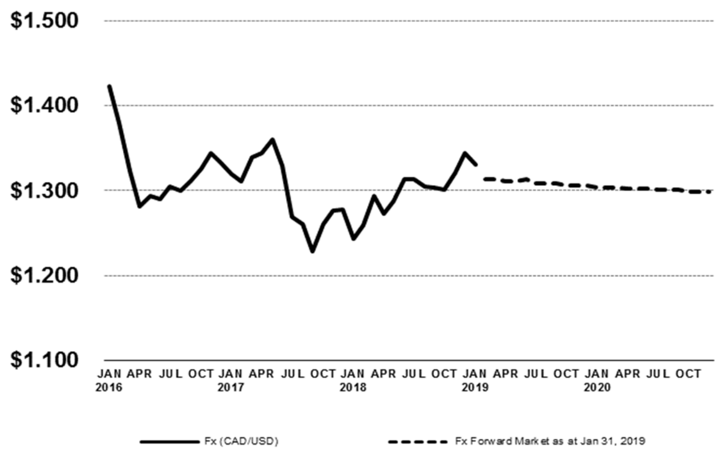


FOREIGN EXCHANGE

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

The Canadian dollar weakened throughout 2018, closing the year at 1.36 US/CDN compared to 1.26 US/CDN at December 31, 2017 and averaging 1.30 US/CDN throughout the year. The weakness in the Canadian dollar was driven by decelerating domestic economic growth, changing U.S. and Canada trade policies including the renegotiation of the North American Free Trade Agreement, as well as interest rates in the U.S. and Canada.

Monthly USD/CDN Exchange Rate



Price Risk Management

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

As of February 20, 2019, we have hedged approximately 23,100 bbls/day of our expected crude oil production for 2019, which represents approximately 63% of our 2019 forecasted crude oil production, after royalties. For 2020, we have hedged 16,000 bbls/day, which represents approximately 43% of our 2019 forecasted crude oil production, after royalties. Our crude oil hedges are predominantly three-way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike price, the three-way collars 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.

As of February 20, 2019, we have hedged approximately 65,700 Mcf/day of our forecasted natural gas production for 2019. This represents approximately 34% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at February 20, 2019, expressed as a percentage of our forecasted 2019 net production volumes:

	WTI Crude Oil (US$/bbl)(1)(2)				
	Jan 1, 2019 – Mar 31, 2019	**Apr 1, 2019 – Jun 30, 2019**	**July 1, 2019 – Sep 30, 2019**	**Oct 1, 2019 – Dec 31, 2019**	**Jan 1, 2020 – Dec 31, 2020**
Swaps					
Sold Swaps	$ 53.73	-	-	-	-
%	8%	-	-	-	-
Three Way Collars					
Sold Puts	$ 44.28	$ 44.50	$ 44.64	$ 44.64	$ 46.88
%	46%	63%	66%	66%	43%
Purchased Puts	$ 54.12	$ 54.59	$ 54.81	$ 54.81	$ 57.50
%	46%	63%	66%	66%	43%
Sold Calls	$ 64.12	$ 65.52	$ 65.95	$ 65.99	$ 72.50
%	46%	63%	66%	66%	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 97,000 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 spent on our three-way collars is US$1.61/bbl from January 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[1]	
	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Oct 31, 2019
Swaps		
Sold Swaps	$ 4.23	$ 2.85
%	26%	36%
Collars		
Purchased Puts	$ 3.80	-
%	26%	-
Sold Calls	$ 6.01	-
%	26%	-

(1) Based on weighted average price (before premiums) assuming average annual production of 97,000 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)

($ millions)	2018	2017	2016
Cash gains/(losses):			
Crude oil	$ (52.0)	$ 0.9	$ 75.0
Natural gas	16.2	7.7	5.3
Total cash gains/(losses)	$ (35.8)	$ 8.6	$ 80.3
Non-cash gains/(losses):			
Crude oil	$ 114.8	$ (5.4)	$ (96.2)
Natural gas	9.2	11.1	(13.5)
Total non-cash gains/(losses)	$ 124.0	$ 5.7	$ (109.7)
Total gains/(losses)	$ 88.2	$ 14.3	$ (29.4)

(Per BOE)	2018	2017	2016
Total cash gains/(losses)	$ (1.05)	$ 0.28	$ 2.36
Total non-cash gains/(losses)	3.64	0.18	(3.22)
Total gains/(losses)	$ 2.59	$ 0.46	$ (0.86)

During 2018, we realized cash losses of $52.0 million on our crude oil contracts and gains of $16.2 million on our natural gas contracts. The realized cash losses were the result of crude oil prices rising above the swap level and the sold call strike price on our three-way collars. Cash gains on our natural gas contracts included a gain of $15.1 million on the unwind of a portion of our AECO-NYMEX basis physical contracts. In 2017, we realized cash gains of $0.9 million on our crude oil contracts and $7.7 million on our natural gas contracts, which included a gain of $8.5 million on the unwind of a portion of our AECO-NYMEX basis physical contracts. During 2016, we realized cash gains of $75.0 million on our crude oil contracts and $5.3 million on our natural gas contracts. The cash gains in 2017 and 2016 were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. The fair value of our crude oil contracts and natural gas contracts at December 31, 2018 were in a net asset position of $80.5 million and $10.9 million, respectively (December 31, 2017 – net liability position of $34.3 million and net asset position of $1.7 million, respectively). The change in fair value of our crude oil and natural gas contracts represented gains of $114.8 million and $9.2 million, respectively, during 2018 and losses of $5.4 million and gains of $11.1 million, respectively, during 2017.

Revenues

($ millions)	2018	2017	2016
Oil and natural gas sales	$ 1,610.9	$ 1,141.8	$ 882.1
Royalties	(318.2)	(221.1)	(159.4)
Oil and natural gas sales, net of royalties	$ 1,292.7	$ 920.7	$ 722.7

Oil and natural gas sales revenue for 2018 totaled $1,610.9 million, an increase of 41% from $1,141.8 million in 2017. The increase in revenue was a result of higher liquids production and an improvement in crude oil prices.

In 2017, oil and natural gas sales revenue increased 29% to $1,141.8 million from $882.1 million in 2016. The increase in 2017 is a result of the improvement in commodity prices and realized sales price differentials, along with a higher crude oil and natural gas liquids weighting of 48% compared to 46% in 2016.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2018	2017	2016
Royalties	$ 318.2	$ 221.1	$ 159.4
Per BOE	$ 9.35	$ 7.15	$ 4.67
Production taxes	$ 87.3	$ 54.3	$ 37.4
Per BOE	$ 2.57	$ 1.76	$ 1.10
Royalties and production taxes	$ 405.5	$ 275.4	$ 196.8
Per BOE	$ 11.92	$ 8.91	$ 5.77
Royalties and production taxes (% of oil and natural gas sales)	25%	24%	22%

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

Royalties and production taxes were in line with our guidance for 2018, averaging 25% of oil and natural gas sales, before transportation. Royalties and production taxes increased to $405.5 million in 2018 from $275.4 million in 2017 and $196.8 million in 2016, mainly due to a larger portion of production volumes coming from our U.S. properties, as well as higher crude oil and natural gas realized prices.

2019 Guidance

We expect royalty and production taxes in 2019 to average 25% of our oil and gas sales before transportation, which is consistent with 2018 levels.

Operating Expenses

($ millions, except per BOE amounts)	2018	2017	2016
Cash operating expenses	$ 238.3	$ 197.7	$ 249.0
Non-cash (gains)/losses[1]	-	(0.6)	(1.1)
Total operating expenses	$ 238.3	$ 197.1	$ 247.9
Per BOE	$ 7.00	$ 6.37	$ 7.27

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

Operating expenses for 2018 were $238.3 million or $7.00/BOE, consistent with our revised guidance of $7.00/BOE and representing an increase of $41.2 million ($0.63/BOE) from the prior year. The increase is mainly attributable to our higher liquids production as our liquids weighting increased to 54% from 48% in the prior year. Our liquids production has higher associated operating cost metrics, which was partially offset by the divestment of higher operating cost Canadian properties during 2017.

Operating expenses during 2017 were $197.1 million or $6.37/BOE compared to $247.9 million or $7.27/BOE in 2016. The improvement was mainly the result of cost savings initiatives combined with the divestment of higher operating cost Canadian properties.

2019 Guidance

We expect operating expenses of $8.00/BOE in 2019. The increase from 2018 is primarily a result of our liquids growth contributing to a higher proportion of our total production, as well as an increase in gas processing costs and use of electrical submersible pumps in North Dakota.

Transportation Costs

($ millions, except per BOE amounts)	2018	2017	2016
Transportation costs	$ 123.5	$ 111.3	$ 107.1
Per BOE	$ 3.63	$ 3.60	$ 3.14

Transportation costs in 2018 were in line with our guidance of $3.60/BOE averaging $3.63/BOE, and similar to $3.60/BOE in 2017. Transportation costs increased to $3.60/BOE in 2017, compared to $3.14/BOE in 2016 due to additional transportation commitments in the Marcellus that commenced in August 2016 and our growing U.S. production volumes which have higher associated transportation costs.

2019 Guidance

We expect transportation costs to increase to $4.00/BOE in 2019, due to additional crude oil firm transportation commitments that provide access to sell a portion of our production at U.S. gulf coast or Brent pricing.

Netbacks

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

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

	Year ended December 31, 2017		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,496 BOE/day	241,290 Mcfe/day	84,711 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 53.38	$ 3.12	$ 36.93
Royalties and production taxes	(13.89)	(0.57)	(8.91)
Cash operating expenses	(10.20)	(0.36)	(6.39)
Transportation costs	(2.21)	(0.86)	(3.60)
Netback before hedging	$ 27.08	$ 1.33	$ 18.03
Cash gains/(losses)	0.06	0.09	0.28
Netback after hedging	$ 27.14	$ 1.42	$ 18.31
Netback before hedging ($ millions)	$ 439.8	$ 117.6	$ 557.4
Netback after hedging ($ millions)	$ 440.7	$ 125.2	$ 566.0

	Year ended December 31, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	47,206 BOE/day	275,538 Mcfe/day	93,125 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 37.86	$ 2.26	$ 25.88
Royalties and production taxes	(9.38)	(0.34)	(5.77)
Cash operating expenses	(10.29)	(0.72)	(7.31)
Transportation costs	(1.97)	(0.72)	(3.14)
Netback before hedging	$ 16.22	$ 0.48	$ 9.66
Cash gains/(losses)	4.34	0.05	2.36
Netback after hedging	$ 20.56	$ 0.53	$ 12.02
Netback before hedging ($ millions)	$ 280.4	$ 48.8	$ 329.2
Netback after hedging ($ millions)	$ 355.3	$ 54.2	$ 409.5

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

Crude oil and natural gas netbacks per BOE before hedging were higher during 2018 compared to 2017 and 2016 primarily due to higher realized crude oil prices. During 2018, our crude oil properties accounted for 84% and 82% of our netback before and after hedging, respectively. During 2017, our crude oil properties accounted for 79% and 78% of our netback before and after hedging, respectively.

General and Administrative Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 10, Note 13 and Note 14 to the Financial Statements for further details.

($ millions)	2018	2017	2016
Cash:			
G&A expense	$ 50.0	$ 50.5	$ 59.8
Share-based compensation expense	0.1	1.0	3.1
Non-Cash:			
Share-based compensation expense	25.9	22.6	27.0
Equity swap loss/(gain)	(0.2)	0.2	(3.6)
Total G&A expenses	$ 75.8	$ 74.3	$ 86.3

(Per BOE)	2018	2017	2016
Cash:			
G&A expense	$ 1.47	$ 1.63	$ 1.75
Share-based compensation expense	0.01	0.03	0.09
Non-Cash:			
Share-based compensation expense	0.76	0.73	0.80
Equity swap loss/(gain)	(0.01)	0.01	(0.11)
Total G&A expenses	$ 2.23	$ 2.40	$ 2.53

Cash G&A expenses in 2018 totaled $50.0 million ($1.47/BOE), beating our guidance of $1.50/BOE and consistent with $50.5 million ($1.63/BOE) in 2017.

During the year, we reported cash SBC on our Deferred Share Unit ("DSU") plan of $0.1 million, compared to $1.0 million in 2017 due to a decrease in our share price at December 31, 2018 on outstanding deferred share units. We recorded non-cash SBC of $25.9 million ($0.76/BOE) in 2018 compared to $22.6 million ($0.73/BOE) in 2017. The increase in non-cash SBC in 2018 was a result of a recovery recorded in 2017 due to the forfeiture of units that were previously expensed.

Cash G&A expenses in 2017 were $50.5 million ($1.63/BOE), a decrease of 16% from $59.8 million ($1.75/BOE) in 2016. Cash SBC expense was $1.0 million ($0.03/BOE) in 2017 compared to an expense of $3.1 million ($0.09/BOE) in 2016. We recorded non-cash SBC of $22.6 million ($0.73/BOE) in 2017 compared to $27.0 million ($0.80/BOE) in 2016. The decrease in non-cash SBC was a result of the increased forfeiture of units in 2017.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. We recorded a non-cash mark-to-market gain of $0.2 million on these hedges in 2018 (2017 – $0.2 million loss; 2016 – $3.6 million gain), which included the settlement of a portion of our equity swaps. As of December 31, 2018, we have 195,000 units hedged at a weighted average price of $20.60 per share.

2019 Guidance

We expect our cash G&A expense to be $1.50/BOE in 2019, which is consistent with 2018.

Interest Expense

Interest on our senior notes and bank credit facility in 2018 totaled $36.8 million compared to $38.7 million in 2017 and $45.4 million in 2016. Interest expense decreased 5% in 2018 when compared to 2017 primarily due to the repayment of a portion of our 2009 senior notes which carry a higher coupon rate.

Interest expense decreased 15% in 2017 when compared to 2016 due to our undrawn bank credit facility, the impact of the strengthening Canadian dollar on our U.S. denominated interest payments and the payment of the first of five annual principal instalments on our 2009 senior notes.

At December 31, 2018, we were undrawn on our $800 million bank credit facility and our debt consisted of fixed interest rate senior notes with a weighted average interest rate of 4.8%. See Note 7 to the Financial Statements for further details on our outstanding notes.

Foreign Exchange

($ millions)	2018	2017	2016
Realized:			
Foreign exchange loss/(gain) on settlements	$ 0.5	$ 1.5	$ 0.1
Translation of U.S. dollar cash held in Canada loss/(gain)	(19.6)	11.0	—
Unrealized loss/(gain)	58.6	(42.6)	(40.6)
Total foreign exchange loss/(gain)	$ 39.5	$ (30.1)	$ (40.5)
US/CDN average exchange rate	1.30	1.30	1.32
US/CDN period end exchange rate	1.36	1.26	1.34

We recorded a net foreign exchange loss of $39.5 million in 2018 compared to gains of $30.1 million and $40.5 million in 2017 and 2016, respectively. 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.

In 2018, we recorded a realized foreign exchange gain of $19.1 million, due to the weakening Canadian dollar compared to a loss of $12.5 million and $0.1 million in 2017 and 2016, respectively.

Comparing December 31, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $58.6 million. See Note 11 to the Financial Statements for further details.

Capital Investment

($ millions)	2018	2017	2016
Capital spending	$ 593.9	$ 458.0	$ 209.1
Office capital	6.5	2.7	1.5
Sub-total	600.4	460.7	210.6
Property and land acquisitions	$ 25.8	$ 13.3	$ 126.1
Property divestments	(6.9)	(56.2)	(670.4)
Sub-total	18.9	(42.9)	(544.3)
Total(1)	$ 619.3	$ 417.8	$ (333.7)

(1) Excludes changes in non-cash investing working capital. See Note 17(b) of the Consolidated Financial Statements for additional information.

2018

Capital spending in 2018 totaled $593.9 million, in line with our guidance of $585 million. Our capital spending in 2018 was 30% higher than 2017, as we continued to execute on our growth plans. In 2018, we spent $474.4 million on our U.S. crude oil properties, $46.3 million on our Canadian crude oil properties, and $66.2 million on our Marcellus natural gas assets. Through our capital program in 2018, we added 65.7 MMBOE of gross proved plus probable reserves, replacing 194% of our 2018 production, before accounting for acquisitions and divestments.

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

2017

Capital spending in 2017 totaled $458.0 million and was more than twice our spending levels in 2016, as we repositioned ourselves for growth. In 2017 we spent $343.0 million on our U.S. crude oil properties, $55.3 million on our Canadian crude oil properties, and $58.5 million on our Marcellus natural gas assets. In 2017, we added 58.0 MMBOE of gross proved plus probable reserves, replacing 189% of our 2017 production, before accounting for acquisitions and divestments.

We recorded net divestment proceeds of $56.2 million in 2017 consisting mainly of our second quarter sale of our Brooks waterflood property and Canadian shallow gas assets. Total divestments had combined production of 7,700 BOE/day and resulted in a $72.3 million reduction to future asset retirement obligations. Property and land acquisitions in 2017 totaled $13.3 million and included additional leases and minor undeveloped land.

2016

Capital spending in 2016 totaled $209.1 million and was focused on our core areas with spending of $136.4 million on our North Dakota crude oil properties, $44.4 million on our Canadian crude oil waterflood properties and $24.3 million on our Marcellus natural gas assets.

We recorded net divestment proceeds of $670.4 million in 2016. In Canada, we sold properties consisting mainly of natural gas assets, which included certain Deep Basin natural gas properties and non-core properties in northwest Alberta with combined production of approximately 8,500 BOE/day. On December 30, 2016, we closed the sale of our non-operated assets in North Dakota with production of approximately 5,000 BOE/day for proceeds of $392.0 million. Through our capital program in 2016 we added 43 MMBOE of gross proved plus probable reserves, replacing 126% of our 2016 production, before accounting for acquisitions and divestments.

Property and land acquisitions in 2016 totaled $126.1 million, largely due to our acquisition of a Canadian waterflood property for a purchase price of $110.3 million, net of closing adjustments.

2019 Guidance

Our capital spending guidance for 2019 is between $565 million and $635 million, and is expected to deliver annual liquids production growth of 9%. Our spending is focused on our core areas, with approximately $480 million allocated to North Dakota, $45 million to our Marcellus gas properties, $45 million to our Canadian crude oil waterflood properties, and $30 million allocated to the DJ Basin.

Gain on Asset Sales and Note Repurchases

Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. No gains or losses were recorded on asset sales in 2018. We recorded gains of $78.4 million during 2017 related to the divestment of our Brooks waterflood property and Canadian shallow gas assets. In 2016, a gain of $559.2 million was recorded on asset divestments, which included a gain of $339.4 million on the fourth quarter sale of our non-operated North Dakota property. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment.

During 2018 and 2017 we did not repurchase any of our senior notes. During the first half of 2016, we recorded a total gain of $19.3 million on the repurchase of US$267 million of outstanding senior notes at prices between 90% of par and par value.

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

($ millions, except per BOE amounts)	2018	2017	2016
DD&A expense	$ 304.3	$ 250.8	$ 329.0
Per BOE	$ 8.94	$ 8.11	$ 9.65

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. Total DD&A in 2018 increased from 2017 mainly due to a 10% percent increase in overall production. On a per BOE basis, DD&A for 2018 increased as a result of higher capital spending and additional future development capital associated with undeveloped reserve additions. In 2017, DD&A decreased from the prior year mostly due to asset impairments recorded during 2016 under the U.S. GAAP full cost ceiling test methodology.

Impairments

PP&E

($ millions)	2018	2017	2016
Canada cost centre	$ —	$ —	$ 89.4
U.S. cost centre	—	—	211.8
Total Impairments	$ —	$ —	$ 301.2

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

The trailing twelve-month average crude oil and natural gas prices generally improved throughout 2018 and 2017 and no impairments were recorded. In comparison, trailing twelve-month average commodity prices weakened significantly in 2016, resulting in non-cash impairments totaling $301.2 million (before taxes).

The following table outlines the twelve-month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2018, 2017 and 2016:

Year	WTI Crude Oil US$/bbl	Exchange Rate US/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
2018	$ 65.56	1.28	$ 69.58	$ 3.10	$ 1.67
2017	$ 51.34	1.30	$ 63.57	$ 2.98	$ 2.32
2016	$ 42.75	1.32	$ 52.26	$ 2.49	$ 2.17

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the next year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. There is the potential for trailing twelve-month average commodity prices to decline, impacting the ceiling value which could result in non-cash impairments.

Goodwill

Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We first perform a qualitative assessment of goodwill by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value we perform a quantitative impairment test. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss) in the Financial Statements.

Our annual goodwill impairment assessments at December 31, 2018, 2017, and 2016 resulted in no impairment.

Asset Retirement Obligation

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

We have estimated the net present value of our asset retirement obligation to be $126.1 million at December 31, 2018, compared to $117.7 million at December 31, 2017. The increase was largely due to an increase in expected remediation and reclamation estimates and a decrease in our weighted average credit-adjusted risk-free rate used to determine the net present value of the liability. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2018, we spent $11.3 million (2017 – $12.9 million) on our asset retirement obligations and we expect to spend approximately $12.0 million in 2019. The majority of our abandonment, reclamation and remediation costs are expected to be incurred between 2025 and 2055. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment, reclamation and remediation costs are anticipated to be funded out of cash flow and available credit facilities.

Income Taxes

($ millions)	2018	2017	2016
Current tax expense/(recovery)	$ (27.1)	$ (48.0)	$ (2.4)
Deferred tax expense/(recovery)	130.3	129.9	(234.8)
Total tax expense/(recovery)	$ 103.2	$ 81.9	$ (237.2)

Our current tax recovery in 2018 was $27.1 million compared to $48.0 in 2017. The recoveries primarily related to the reclassification of AMT refunds from our deferred income tax asset in the amounts of $27.2 million and $50.1 million, respectively. The remaining $27.2 million in AMT refunds are expected to be reclassified to current tax in 2019 and 2020.

The total tax expense in 2018 was $103.2 million compared to $81.9 in 2017 primarily due to higher overall income in 2018. The deferred tax expense in 2017 included $46.2 million from the remeasurement of our U.S. deferred income tax assets for the federal income tax rate reduction from 35% to 21% after enactment of the U.S. Tax Cuts and Jobs Act, offset by the reversal of the valuation allowance previously recorded on our AMT refund. We assess the recoverability of our deferred income tax assets each period to determine whether it is, more likely than not, all or a portion of our deferred income tax assets will be realized. We consider available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. Our overall deferred income tax asset, net of valuation allowance, was $465.1 million as at December 31, 2018 (2017 - $569.9 million). Our remaining valuation allowance is primarily related to our net capital loss carryforward balance. We do not anticipate future capital gains that will allow us to utilize these losses.

Our estimated tax pools at December 31, 2018 are as follows:

Pool Type ($ millions)		**2018**
Canada		
Canadian oil and gas property ("COGPE")	$	6
Canadian development expenditures ("CDE")		91
Canadian exploration expenditures ("CEE")		238
Undepreciated capital costs ("UCC")		149
Non-capital losses and other credits		428
	$	912
U.S.		
Alternative minimum tax credit ("AMT")	$	58
Net operating losses		1,052
Depletable and depreciable assets		870
	$	1,980
Total tax pools and credits	$	2,892
Capital losses	$	1,226

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. Our senior debt to adjusted EBITDA ratio decreased to 0.9x at December 31, 2018 from 1.2x at December 31, 2017 as a result of an increase in our trailing twelve-month EBITDA, which benefited from increased revenue in 2018. Our net debt to adjusted funds flow ratio improved to 0.4x at December 31, 2018 from 0.6x at December 31, 2017 as a result of the significant increase in our adjusted funds flow in 2018. 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 December 31, 2018 increased slightly to $333.5 million compared to $325.8 million at December 31, 2017. Total debt was comprised of $696.8 million in senior notes less $363.3 million in cash. The increase compared to the prior year was a result of the impact of a weaker Canadian dollar at December 31, 2018 on our U.S. dollar denominated senior notes, which more than offset a $16.8 million increase in cash. Our next scheduled senior note repayments of $30 million and US$22 million are due in May and June 2019, respectively, with remaining maturities extending to 2026. At December 31, 2018, we were undrawn on our $800 million bank facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 84% for 2018 compared to 93% in 2017. After adjusting for net acquisition and divestment proceeds, our funding surplus for the year ended December 31, 2018 was $104.9 million compared to $77.2 million in 2017. A portion of the funding surplus in 2018 was used to return approximately $79.0 million of capital to shareholders through repurchasing 5,925,084 common shares under the NCIB at an average price of $13.33 per share. The Company also paid $29.3 million in dividends in 2018. We expect to continue to pay monthly dividends to our shareholders of $0.01 per share, however, if economic conditions change we may make adjustments.

Our working capital deficiency, excluding cash and cash equivalents and current derivative assets and liabilities, increased to $143.1 million at December 31, 2018 from $107.6 million at December 31, 2017. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under "Commitments" below.

During the fourth quarter, we completed a one-year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2021. There were no significant amendments to the agreement terms or debt covenants. Drawn fees on our bank credit facility range between 125 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 125 basis points over Banker's Acceptance rates based on our current reported senior net debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior unsecured covenant-based notes.

At December 31, 2018 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants at December 31, 2018:

Covenant Description		December 31, 2018
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [1]	3.5x	0.9x
Total debt to adjusted EBITDA [1]	4.0x	0.9x
Total debt to capitalization	50%	19%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [1][2]	3.0x – 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves [3]	60%	21%
	Minimum Ratio	
Adjusted EBITDA to interest [1]	4.0x	21.3x

Definitions
"Senior Debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended December 31, 2018 were $209.7 million and $782.8 million, respectively.
"Total Debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.
(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Counterparty Credit

OIL AND NATURAL GAS SALES COUNTERPARTIES

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

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. All of our derivative counterparties are considered investment grade. At December 31, 2018, we had $91.5 million in mark-to-market assets offset by $1.9 million of mark-to-market liabilities resulting in a net asset position of $89.6 million.

Dividends

($ millions, except per share amounts)	2018	2017	2016
Cash dividends [(1)]	$ 29.3	$ 29.0	$ 35.4
Per weighted average share (Basic)	$ 0.12	$ 0.12	$ 0.16

(1) Excludes changes in non-cash financing working capital. See Note 17(b) of the Consolidated Financial Statements for additional information.

We reported total dividends of $29.3 million or $0.12 per share to our shareholders in 2018. During 2017 and 2016, we reported total dividends of $29.0 million or $0.12 per share and $35.4 million or $0.16 per share, respectively.

Effective for our April 2016 dividend, we reduced our monthly dividend to $0.01 per share from $0.03 per share.

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

	2018	2017	2016
Share capital ($ millions)	$ 3,337.6	$ 3,386.9	$ 3,366.0
Common shares outstanding (thousands)	239,411	242,129	240,483
Weighted average shares outstanding – basic (thousands)	244,076	241,929	226,530
Weighted average shares outstanding – diluted (thousands)	247,261	247,874	231,293

During 2018, a total of 668,000 shares were issued pursuant to our stock option plan resulting in additional share capital of $9.1 million, and $0.7 million transferred from paid-in capital to share capital (2017 and 2016 – nil). During 2018, a total of 2,539,000 shares were issued pursuant to our treasury-settled LTI plans and $23.4 million was transferred from paid-in capital to share capital (2017 – 1,646,000 and $21.0 million; 2016 – 594,000 and $9.4 million).

On March 21, 2018, Enerplus announced the acceptance of its NCIB by the Toronto Stock Exchange ("TSX"). The bid allows Enerplus to purchase up to 17,095,598 common shares on the TSX, the New York Stock Exchange and/or alternative Canadian trading systems over a period of twelve months commencing on March 26, 2018. All common shares purchased under the bid will be cancelled. During the year ended December 31, 2018, the Company repurchased 5,925,084 common shares under the NCIB at an average price of $13.33 per share, for total consideration of $79.0 million. Of the amount paid, $82.6 million was recorded to share capital and $3.6 million was credited to accumulated deficit. Subsequent to the year, and up to February 20, 2019, the Company repurchased 586,953 common shares under the NCIB at an average price of $11.40 per share, for consideration of $6.7 million. The Company also received approval from the Board of Directors to renew the NCIB upon expiry of the existing term on March 25, 2019, subject to approval by the TSX. The proposed renewal will be for 7% of public float (within the meaning under the TSX rules) consistent with the current bid.

On May 31, 2016, 33,350,000 common shares were issued at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs before tax).

At February 20, 2019, we had 238,824,149 shares outstanding. In addition, an aggregate of 8,599,059 common shares may be issued to settle outstanding grants under the PSU, RSU, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

For further details see Note 13 to the Financial Statements.

Commitments

We have the following minimum annual commitments:

($ millions)	Total	2019	2020	2021	2022	2023	Total Committed after 2023
		Minimum Annual Commitment Each Year					
Senior notes[1]	$ 696.8	$ 60.0	$ 111.3	$ 111.3	$ 109.9	$ 108.6	$ 195.7
Transportation commitments[2]	367.6	36.8	37.9	34.1	31.4	30.3	197.1
Processing commitments	16.2	3.5	3.2	1.5	1.5	1.5	5.0
Drilling and completions	51.4	20.0	20.0	11.4	—	—	—
Office lease commitments	73.7	9.4	10.7	11.2	11.3	11.4	19.7
Sublease recoveries	(15.4)	(3.2)	(3.4)	(3.2)	(2.4)	(1.7)	(1.5)
Net office lease commitments	58.3	6.2	7.3	8.0	8.9	9.7	18.2
Total commitments[3][4]	$ 1,190.3	$ 126.5	$ 179.7	$ 166.3	$ 151.7	$ 150.1	$ 416.0

(1) Interest payments have not been included.
(2) Includes additional firm transportation commitments executed subsequent to year-end.
(3) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(4) US$ commitments have been converted to CDN$ using the December 31, 2018 foreign exchange rate of 1.3637.

In the Marcellus, we have firm transportation agreements in place for approximately 66,000 Mcf/day, which expire between 2020 and 2036. This includes an agreement for firm pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections for 30,000 Mcf/day of natural gas until mid-2027, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of US$90.4 million through 2036. We have also entered into a binding contract for five years of firm transportation capacity for 30,000 Mcf/day on the PennEast pipeline project. This project has been approved by the Federal Energy Regulatory Commission, however, it is currently awaiting state level approvals with an expected in-service date during 2020. In the Bakken region, subsequent to year end, we entered into a multi-year contract for firm pipeline capacity to transport a portion of our crude oil production to the U.S. Gulf Coast.

In Canada, we have various firm transportation agreements for approximately 3,200 BOE/day of our crude oil and natural gas liquids production in 2019, decreasing to approximately 1,400 BOE/day on average from 2020 to 2027. We also have firm natural gas transportation contracts in 2019 for approximately 48,000 Mcf/day. At December 31, 2018, we have firm natural gas liquids fractionation contracts for 1,100 BOE/day through 2027.

Our commitments and contingencies are more fully described in Note 15 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

(millions, except per unit amounts)	Year ended December 31, 2018 Canada	U.S.	Total	Year ended December 31, 2017 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	9,282	36,142	45,424	10,779	26,156	36,935
Natural gas liquids (bbls/day)	1,064	3,422	4,486	1,193	2,665	3,858
Natural gas (Mcf/day)	27,497	232,340	259,837	46,228	217,278	263,506
Total average daily production (BOE/day)	14,929	78,287	93,216	19,677	65,034	84,711
Pricing[2]						
Crude oil (per bbl)	$ 55.50	$ 79.49	$ 74.59	$ 51.87	$ 61.50	$ 58.69
Natural gas liquids (per bbl)	45.22	23.05	28.31	38.13	26.38	30.01
Natural gas (per Mcf)	2.90	3.49	3.42	3.30	3.19	3.21
Capital Expenditures						
Capital spending	$ 53.3	$ 540.6	$ 593.9	$ 56.5	$ 401.5	$ 458.0
Acquisitions	4.2	21.6	25.8	4.7	8.6	13.3
Divestments	1.2	(8.1)	(6.9)	(56.6)	0.4	(56.2)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 237.9	$ 1,373.0	$ 1,610.9	$ 276.3	$ 865.5	$ 1,141.8
Royalties	(39.6)	(278.6)	(318.2)	(49.3)	(171.8)	(221.1)
Production taxes	(3.1)	(84.2)	(87.3)	(3.3)	(51.0)	(54.3)
Cash operating expenses	(75.2)	(163.1)	(238.3)	(82.1)	(115.6)	(197.7)
Transportation costs	(11.4)	(112.1)	(123.5)	(13.3)	(98.0)	(111.3)
Netback before hedging	$ 108.6	$ 735.0	$ 843.6	$ 128.3	$ 429.1	$ 557.4
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (88.2)	$ —	$ (88.2)	$ (14.3)	$ —	$ (14.3)
General and administrative expense[4]	43.3	32.5	75.8	48.9	25.4	74.3
Current income tax expense/(recovery)	(0.4)	(26.7)	(27.1)	(0.4)	(47.6)	(48.0)

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

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2018	2017	2016
Oil and natural gas sales, net of royalties	$ 1,292.7	$ 920.7	$ 722.7
Net income/(loss)	378.3	237.0	397.4
Per share (Basic)	1.55	0.98	1.75
Per share (Diluted)	1.53	0.96	1.72
Adjusted net income[1]	344.8	132.2	240.2
Cash flow from operating activities	738.8	476.1	312.3
Adjusted funds flow[1]	753.5	524.1	305.6
Cash dividends[2]	29.3	29.0	35.4
Per share (Basic)[2]	0.12	0.12	0.16
Total assets	3,118.3	2,645.8	2,638.9
Total debt	696.8	672.4	768.8
Total debt net of cash[1]	333.5	325.8	375.5

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

2018 versus 2017

Net oil and natural gas sales were $1,292.7 million in 2018 compared to $920.7 million in 2017 due to higher realized commodity prices, increased production and higher crude oil and natural gas liquids weighting in 2018.

We reported net income of $378.3 million in 2018 compared to $237.0 million in 2017. The increase in 2018 was primarily due to increased oil and natural gas sales and higher gains on commodity derivative instruments, which were offset in part by no gains on asset divestments and increased foreign exchange losses compared to 2017.

Cash flow from operating activities and adjusted funds flow increased to $738.8 million and $753.5 million, respectively, in 2018 from $476.1 million and $524.1 million in 2017. The increase was mainly due to a $372.0 million increase in net oil and gas natural gas sales, offset by realized losses on derivative instruments and higher operating expenses and production taxes resulting from higher production.

2017 versus 2016

Net oil and natural gas sales were $920.7 million in 2017 compared to $722.7 million in 2016 due to higher realized commodity prices, offset by the impact of lower production volumes as a result of our asset divestments over that period.

We reported net income of $237.0 million in 2017 compared to $397.4 million in 2016. The decrease in 2017 was primarily due to a $480.8 million decrease in gains being recorded on the divestment of assets during the period and a gain recorded in 2016 for $19.3 million related to the prepayment of senior notes. We also recorded a deferred tax expense of $129.9 million in 2017 compared to a deferred tax recovery of $234.8 million in 2016, due to higher net income before taxes and the impact of the U.S. Tax Legislation on our U.S. deferred income tax assets.

Cash flow from operating activities and adjusted funds flow increased to $476.1 million and $524.1 million, respectively, in 2017 from $312.3 million and $305.6 million in 2016. The increase was mainly due to a $198.0 million increase in net oil and gas natural gas sales, lower operating costs, interest, and cash G&A expenses, offset by lower realized cash gains on commodity hedges. Adjusted funds flow in 2017 benefited from a $50.1 million AMT refund realized in 2018.

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
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 in 2018 compared to 2017 due to an increase in realized commodity prices and higher production volumes. Although production levels increased throughout 2018, declining commodity prices during the fourth quarter of 2018 resulted in lower net sales for this period.

Net income increased to $378.3 million in 2018 due to higher net sales and non-cash gains on commodity derivatives as commodity prices fell during the fourth quarter.

During 2017, we reported net income of $237.0 million which included a gain of $78.4 million on the divestment of certain Canadian assets during the second quarter.

ENVIRONMENT

We strive to carry out our activities and operations in compliance with all applicable regulations and best industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to maintain our strong environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

We have a Safety and Social Responsibility Policy ("S&SR Policy"), which articulates our commitment to health and safety, stakeholder engagement, environmental and regulatory compliance. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with the S&SR Policy. The Safety & Social Responsibility Committee of our Board of Directors (the "S&SR Committee") is responsible for overseeing our S&SR performance, ensuring there are adequate systems in place to support ongoing compliance, and to plan the Company's activities in a safe and socially responsible manner.

We have established processes and programs designed to evaluate and minimize health, safety, and environmental risks, and strive for continuous improvement in our S&SR performance. We also actively participate in industry recognized programs that support our sustainability goals.

The S&SR Policy articulates our commitment to protecting the health and safety of all persons and communities involved in, or affected by, our business activities, and articulates our commitment to the environment. It states we endeavor to: (i) proactively manage our impact on the environment and consider innovative improvement opportunities; (ii) work to reduce our environmental impact in the areas in which we operate; (iii) improve our water and land use practices; (iv) limit the waste we generate; (v) prevent and manage environmental releases; (vi) provide transparent disclosure; and (vii) provide resources and training to meet our environmental commitments. Our commitment to building meaningful and transparent relationships, engaging with our stakeholders, and adhering to responsible development of resources and regulatory compliance is also stated.

We intend to continue to improve energy efficiencies and proactively manage our greenhouse gas emissions in compliance with applicable government regulations, including regulations enacted at the provincial, state, and federal levels in which we operate.

There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have an active site inspection program, corrosion risk management strategy and asset integrity management program to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of releases should they occur.

Some of our operations use hydraulic fracturing techniques, which involves the injection of pressurized fluids, sand, and small amounts of additives into a well bore. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations and industry best practices in the U.S. and Canada.

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

We publish a Corporate Sustainability Report in accordance with the Global Reporting Initiative (GRI) international standard. The report summarizes our environmental, safety, social responsibility and governance performance, and can be found on our website at www.enerplus.com.

Overall, we strive to operate in a socially responsible manner and believe our health, safety and environmental initiatives and performance confirm our ongoing commitment to environmental stewardship and the health and safety of our employees, contractors, and the public in the communities in which we operate.

CRITICAL ACCOUNTING ESTIMATES

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

Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, valuation allowance on deferred income tax and gain or loss calculations. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

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

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net assets acquired. Goodwill is allocated to reporting units and is assessed for impairment at least annually. To assess impairment, the Company first evaluates qualitative factors, such as industry and market considerations and overall financial performance, to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value including goodwill, a quantitative impairment test is performed. If the carrying amount of the reporting unit exceeds its related fair value, goodwill is written down to its implied fair value. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates.

Income Taxes

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

Asset Retirement Obligation

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

Business Combinations

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

Derivative Financial Instruments

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

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Effective in 2018, Enerplus adopted ASC 606 – *Revenue from contracts with customers.* The adoption of this standard had no impact on the Consolidated Financial Statements, with the exception of additional note disclosures. See Notes 2(o) and 9 to the Consolidated Financial Statements for further details.

Effective January 1, 2019, Enerplus is required to adopt ASC 842 – *Leases.* The adoption of this standard is expected to have a material impact on the Company's Consolidated Financial Statements. See Note 2(o) to the Consolidated Financial Statements for further details.

Refer to Note 2(o) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2018.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and natural gas liquids, economic conditions including currency fluctuations, weather conditions, the level of consumer demand, the ability to export oil and liquefied natural gas and natural gas liquids from North America and the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American crude oil, natural gas and natural gas liquids, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the effect of world-wide energy conservation and greenhouse gas reduction measures, the price and availability of alternative fuels and existing and proposed changes to government regulations.

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

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of crude oil, natural gas liquids, and natural gas price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 20, 2019, approximately 63% of our 2019 forecasted crude oil production, net of royalties, and 34% of our 2019 forecasted natural gas production, net of royalties, are hedged at price levels disclosed in the "Price Risk Management" section above. For 2020 we have also hedged approximately 43%, of our forecasted 2019 crude oil production, net of royalties. Refer to the "Price Risk Management" section for further details on our price risk management program.

Regulatory Risk and Greenhouse Gas Emissions

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

Government regulations may be changed from time to time in response to economic or political conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. Canadian and U.S. governments have enhanced their oversight and reporting obligations associated with fracturing procedures and increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures. Additionally, various levels of Canadian and U.S. governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds ("VOC"), and methane gas emissions.

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

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

Access to Transportation and Processing Capacity

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

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

Access to Field Services

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

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services through 2019, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of proppant, and operating costs such as electricity, chemicals, gas processing, supplies, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our 2019 capital and operating costs protected with existing agreements and contract reopeners, changing regulatory conditions, such as those in the U.S. requiring that certain raw materials be sourced from the U.S., may result in higher than expected supply costs.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation, government regulation or third party operational practices, it could result in a reduction to cash flow and production levels and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. With regard to curtailment, the Government of Alberta announced industry-wide mandatory crude oil production curtailments on December 9, 2018. However, based on our current and anticipated Alberta oil production levels, we are currently exempt from this legislation. Combined with the ongoing volatility in commodity prices, any shortage in pipeline infrastructure in producing regions where we operate may result in discounted prices and an ongoing risk of price-related production curtailments.

Risk of Public Opposition and Activism

The oil and natural gas industry elicits concerns over climate change, as well as general public opposition to the industry. As a result, industry participants such as Enerplus may be subject to increased public activism, as well as extensive environmental regulation. Activist activity may result in increased costs due to delays or damage.

The expansion of our business activities, both geographically and with a focus on exploration, may draw increased attention from shareholder activists who oppose our strategy, which could have an adverse effect on market value. Our ongoing participation in the Canadian and U.S. capital markets may expose us to greater risk of class action lawsuits related to securities law, title, contractual and environmental matters.

Access to Capital Markets

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

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

Anticipated Benefits of Acquisitions or Divestments

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

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

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

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

Changes in Income Tax and Other Laws

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

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

Health, Safety and Environmental Risk

Health, safety and environmental risks impact our workforce and operating costs and result in the enhancement of our business practices and standards. There may be risks associated with hydraulic fracturing or produced water disposal including the risk of induced seismicity with the injection of fluid into any reservoir. We expect regulatory frameworks will be amended or continue to emerge in this regard. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements surrounding hydraulic fracturing. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

We have an S&SR department that develops standards and systems to manage health, safety and environmental risks, and regulatory compliance. The S&SR Committee of our Board of Directors is responsible for overseeing the organization’s health, safety and environmental performance and ensuring there are adequate systems in place to support ongoing compliance, and to plan activities in a safe and socially responsible manner. We have insurance to cover a portion of our property losses, liability and business interruption. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations.

Production Replacement Risk

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

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

Oil and Gas Reserves and Resources Risk

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

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluate or audit the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 95% of the total proved plus probable net present value (discounted at 10% and using NI 51-101 standards) of our reserves at December 31, 2018. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 70% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluations of contingent resources associated with a portion of our Canadian waterflood properties and our North Dakota assets were conducted by Enerplus' qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

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

Cyber Security Risks

We are subject to a variety of information technology and system risks as part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of our information technology systems by third parties or insiders. Although we have security measures and controls in place that are designed to mitigate these risks, a breach of our security and/or a loss of information could occur and result in a loss of material and confidential information, reputation damage, a breach in privacy laws and disruption to business activities. The significance of any such event is difficult to quantify, but may be material in certain circumstances and could have a material effect on our business, financial condition and results of operations.

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

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

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

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We first perform a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, a quantitative impairment test is performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to net income.

We recorded no impairment on our crude oil and natural gas assets in 2018 and 2017. Similarly, no impairment was recognized on our goodwill and deferred tax asset in 2018 and 2017. There is a risk of impairment on our oil and gas properties, deferred tax asset and goodwill if commodity prices weaken, costs increase, or if there is a downward revision to reserves. Please refer to the "Impairments" and "Income Taxes" sections of the MD&A and Notes 5 and 12 of the Financial Statements for further details.

Counterparty and Joint Venture Credit Exposure

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

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

See the "Liquidity and Capital Resources" section for further information.

Title Defects or Litigation

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

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

Foreign Currency Exposure

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

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

Ability to Divest Properties

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

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

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

Our most restrictive debt covenant is a maximum senior debt to adjusted EBITDA ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2018, our senior debt to adjusted EBITDA ratio was 0.9x. We routinely review our compliance with covenants based on actual and forecasted results and have the ability to adjust our capital spending levels and dividends or pursue asset divestments and equity issuances to comply with our covenants.

See the "Liquidity and Capital Resources" section for further information.

Interest Rate Exposure

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

Currently, we do not have any floating interest rate debt. At December 31, 2018, we were undrawn on our $800 million bank credit facility and our debt consisted of fixed interest rate senior notes.

ADJUSTED FUNDS FLOW SENSITIVITY

The sensitivities below reflect all commodity contracts listed in Note 14 to the Financial Statements and are based on 2019 guidance price levels of: WTI - US$50.00/bbl, NYMEX - US$3.00/Mcf and a USD/CDN exchange rate of 1.32. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table		Estimated Effect on 2019 Adjusted Funds Flow per Share(1)
Increase of US$5.00 per barrel in the price of WTI crude oil	$	0.20
Decrease of US$5.00 per barrel in the price of WTI crude oil	$	(0.17)
Change of US$0.50 per Mcf in the price of NYMEX natural gas	$	0.12
Change of 1,000 BOE/day in production	$	0.04
Change of $0.01 in the US/CDN exchange rate	$	0.02
Change of 1% in interest rate(2)	$	nil

(1) Calculated using 239.4 million shares outstanding at December 31, 2018.
(2) There is no impact to adjusted funds flow for an increase in interest rates, as Enerplus is currently undrawn on its floating interest rate bank credit facility and all outstanding senior notes are based on fixed interest rates.

2019 GUIDANCE

A summary of our previously released 2019 guidance is below.

Summary of 2019 Expectations	Target
Capital spending	$565 - $635 million
Average annual production	94,000 – 100,000 BOE/day
Average annual crude oil and natural gas liquids production	52,500 – 56,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$8.00/BOE
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.50/BOE

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.00)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	US$(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 ($ millions)	**Year ended December 31,** **2018**	**2017**	**2016**
Oil and natural gas sales, net of royalties	$ 1,292.7	$ 920.7	$ 722.7
Less:			
Production taxes	(87.3)	(54.3)	(37.4)
Cash operating expenses[1]	(238.3)	(197.7)	(249.0)
Transportation costs	(123.5)	(111.3)	(107.1)
Netback before hedging	$ 843.6	$ 557.4	$ 329.2
Cash gains/(losses) on derivative instruments	(35.8)	8.6	80.3
Netback after hedging	$ 807.8	$ 566.0	$ 409.5

(1) Total operating expenses have been adjusted to exclude non-cash gains of nil in 2018, $0.6 million in 2017, and $1.1 million in 2016.

"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 ($ millions)	**Year ended December 31,** **2018**	**2017**	**2016**
Cash flow from operating activities	$ 738.8	$ 476.1	$ 312.3
Asset retirement obligation expenditures	11.3	12.9	8.4
Changes in non-cash operating working capital	3.4	35.1	(15.1)
Adjusted funds flow	$ 753.5	$ 524.1	$ 305.6

"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 ($ millions)	**Year ended December 31,** **2018**	**2017**	**2016**
Adjusted funds flow	$ 753.5	$ 524.1	$ 305.6
Capital spending	(593.9)	(458.0)	(209.1)
Free cash flow	$ 159.6	$ 66.1	$ 96.5

"Adjusted net income" is used by Enerplus and is useful to investors and securities analyst in evaluating the financial performance of the company by understanding the impact of certain non-cash items and other items that the company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income is calculated as net income adjusted for unrealized derivative instrument gain/loss, asset impairment, gain on divestment of assets, gain on prepayment of senior notes, unrealized foreign exchange gain/loss, and the tax effect of these items.

Calculation of Adjusted Net Income ($ millions)	**Year ended December 31,** **2018**	**2017**	**2016**
Net income/(loss)	$ 378.3	$ 237.0	$ 397.4
Unrealized derivative instrument (gain)/loss	(124.3)	(6.2)	105.0
Asset impairment	-	-	301.2
Gain on divestment of assets	-	(78.4)	(559.2)
Gain on prepayment of senior notes	-	-	(19.3)
Unrealized foreign exchange (gain)/loss	58.6	(42.6)	(40.6)
Tax effect on above items	32.2	22.4	55.7
Adjusted net income	$ 344.8	$ 132.2	$ 240.2

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

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

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

Calculation of Adjusted Payout Ratio	Year ended December 31,		
($ millions)	**2018**	**2017**	**2016**
Cash dividends	$ 29.3	$ 29.0	$ 35.4
Capital and office expenditures	600.4	460.7	210.6
Sub-total	$ 629.7	$ 489.7	$ 246.0
Adjusted funds flow	$ 753.5	$ 524.1	$ 305.6
Adjusted payout ratio (%)	84%	93%	80%

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

Reconciliation of Net Income to Adjusted EBITDA[(1)]	
($ millions)	**December 31, 2018**
Net income/(loss)	$ 378.3
Add:	
Interest	36.8
Current and deferred tax expense/(recovery)	103.2
DD&A and asset impairment	304.3
Other non-cash charges[(2)]	(39.8)
Adjusted EBITDA	$ 782.8

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

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "senior net debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum 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 controls 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 Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2018, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2018 and ended December 31, 2018 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, 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; anticipated production volumes subject to curtailment; 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; operating and transportation costs; our anticipated share 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 current NCIB and share repurchases thereunder; 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 2019 guidance contained in this MD&A is based on the following: a WTI price of US$50.00/bbl to US$55.00/bbl, a NYMEX price of US$3.00/Mcf, and a USD/CDN exchange rate of 1.32. 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 and Form 40-F as at December 31, 2018).

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

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2018, our internal control over financial reporting is effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018, has been audited by KPMG LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2018.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 22, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Enerplus Corporation's (the "Corporation") internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Corporation as of December 31, 2018 and 2017, the related consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the "consolidated financial statements") and our report dated February 22, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 22, 2019

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 21, 2019. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

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

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

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

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 22, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Enerplus Corporation (the "Corporation") as of December 31, 2018 and 2017, the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2018 and 2017, and the results of operations and its cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 22, 2019 expressed an unqualified opinion on the effectiveness of the Corporation's internal control over financial reporting.

Basis for Opinion

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

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

Comparative information

The consolidated financial statements of the Corporation for the year ended December 31, 2016, excluding the impact of adoption of ASU 2016-18 as described in Note 2(f) to the consolidated financial statements, were audited by another auditor who expressed an unqualified (unmodified) opinion on the consolidated financial statements on February 24, 2017.

As part of our audits of the consolidated financial statements as at and for the years ended December 31, 2018 and 2017, we audited the adoption of ASU 2016-18 as described in Note 2(f) to the consolidated financial statements that was applied to amend the comparative information presented for the year ended December 31, 2016. In our opinion, the adoption of ASU 2016-18 has been properly applied.

We were not engaged to audit, review, or apply any procedures to the consolidated financial statements of the Corporation for the year ended December 31, 2016, other than with respect to the amendment described in Note 2(f) to the consolidated financial statements. Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

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

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 22, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

We have audited, before the effects of the adjustments to retrospectively apply ASU 2016-18 adopted in 2017 as discussed in Note 2(f) to the consolidated financial statements, the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the “Company”), which comprise the consolidated statements of income/(loss) and comprehensive income/(loss), consolidated statements of changes in shareholders’ equity, and consolidated statements of cash flows for the year ended December 31, 2016, and the notes to the consolidated financial statements.

Management’s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, such consolidated financial statements, before the effects of the adjustments to retrospectively apply ASU 2016-18 adopted in 2017 as discussed in Note 2(f) to the consolidated financial statements, present fairly, in all material respects, the financial performance and cash flows of Enerplus Corporation and subsidiaries for the year ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

Other Matter

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively adopt ASU 2016-18 as discussed in Note 2(f) to the consolidated financial statements and, accordingly, we do not express an opinion or any other form of assurance about whether such retrospective adjustments are appropriate and have been properly applied. Those retrospective adjustments were audited by other auditors.

/s/ Deloitte LLP

Chartered Professional Accountants
February 24, 2017

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2018	December 31, 2017
Assets			
Current assets			
Cash and cash equivalents		$ 363,327	$ 346,548
Accounts receivable	3	145,206	129,386
Income tax receivable	12	55,172	1,190
Derivative financial assets	14(b)	59,258	3,852
Other current assets		8,928	5,902
		631,891	486,878
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	1,293,941	889,967
Other capital assets, net	4	13,130	10,064
Property, plant and equipment		1,307,071	900,031
Goodwill	5(b)	654,799	638,878
Derivative financial assets	14(b)	32,220	—
Deferred income tax asset	12	465,124	569,937
Income tax receivable	12	27,195	50,108
Total Assets		$ 3,118,300	$ 2,645,832
Liabilities			
Current liabilities			
Accounts payable	6	$ 290,045	$ 213,978
Dividends payable		2,395	2,421
Current portion of long-term debt	7, 14(a)	60,001	27,656
Derivative financial liabilities	14(b)	1,909	28,642
		354,350	272,697
Derivative financial liabilities	14(b)	—	9,907
Long-term debt	7, 14(a)	636,849	644,723
Asset retirement obligation	8	126,112	117,736
		762,961	772,366
Total Liabilities		1,117,311	1,045,063
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2018 – 239 million shares			
December 31, 2017 – 242 million shares	13(a)	3,337,608	3,386,946
Paid-in capital		46,524	75,375
Accumulated deficit		(1,772,084)	(2,124,676)
Accumulated other comprehensive income		388,941	263,124
		2,000,989	1,600,769
Total Liabilities & Shareholders' Equity		$ 3,118,300	$ 2,645,832
Commitments and Contingencies	15		
Subsequent Event	13(a)		

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

Approved on behalf of the Board of Directors:

/s/ Elliott Pew
Director

/s/ Robert B. Hodgins
Director

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

For the year ended December 31 (CDN$ thousands)	Note	2018	2017	2016
Revenues				
Oil and natural gas sales, net of royalties	9	$ 1,292,736	$ 920,693	$ 722,732
Commodity derivative instruments gain/(loss)	14(b)	88,232	14,310	(29,397)
		1,380,968	935,003	693,335
Expenses				
Operating		238,261	197,101	247,917
Transportation		123,463	111,265	107,147
Production taxes		87,286	54,318	37,417
General and administrative	10	75,783	74,301	86,319
Depletion, depreciation and accretion		304,274	250,774	328,964
Asset impairment	5(a)	—	—	301,171
Interest		36,799	38,714	45,443
Foreign exchange (gain)/loss	11	39,521	(30,150)	(40,526)
Gain on divestment of assets	4	—	(78,400)	(559,235)
Gain on prepayment of senior notes	7	—	—	(19,270)
Other expense /(income)		(5,909)	(1,906)	(2,230)
		899,478	616,017	533,117
Income/(Loss) Before Taxes		481,490	318,986	160,218
Current income tax expense/(recovery)	12	(27,093)	(47,957)	(2,351)
Deferred income tax expense/(recovery)	12	130,304	129,945	(234,847)
Net Income/(Loss)		$ 378,279	$ 236,998	$ 397,416
Other Comprehensive Income/(Loss)				
Change in cumulative translation adjustment		125,817	(90,277)	(49,271)
Total Comprehensive Income/(Loss)		$ 504,096	$ 146,721	$ 348,145
Net Income/(Loss) per Share				
Basic	13(c)	$ 1.55	$ 0.98	$ 1.75
Diluted	13(c)	$ 1.53	$ 0.96	$ 1.72

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

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2018**	**2017**	**2016**
Share Capital			
Balance, beginning of year	$ 3,386,946	$ 3,365,962	$ 3,133,524
Public offering (net of issue costs)	—	—	223,031
Purchase of common shares under Normal Course Issuer Bid	(82,596)	—	—
Share-based compensation – settled	23,389	20,984	9,407
Stock Option Plan – cash	9,138	—	—
Stock Option Plan – exercised	731	—	—
Balance, end of year	$ 3,337,608	$ 3,386,946	$ 3,365,962
Paid-in Capital			
Balance, beginning of year	$ 75,375	$ 73,783	$ 56,176
Share-based compensation – cash settled	(30,648)	—	—
Share-based compensation – non-cash settled	(23,389)	(20,984)	(9,407)
Share-based compensation – non-cash	25,917	22,576	27,014
Stock Option Plan – exercised	(731)	—	—
Balance, end of year	$ 46,524	$ 75,375	$ 73,783
Accumulated Deficit			
Balance, beginning of year	$ (2,124,676)	$ (2,332,641)	$ (2,694,618)
Purchase of common shares under Normal Course Issuer Bid	3,569	—	—
Net income/(loss)	378,279	236,998	397,416
Dividends declared	(29,256)	(29,033)	(35,439)
Balance, end of year	$ (1,772,084)	$ (2,124,676)	$ (2,332,641)
Accumulated Other Comprehensive Income			
Balance, beginning of year	$ 263,124	$ 353,401	$ 402,672
Change in cumulative translation adjustment	125,817	(90,277)	(49,271)
Balance, end of year	$ 388,941	$ 263,124	$ 353,401
Total Shareholders' Equity	$ 2,000,989	$ 1,600,769	$ 1,460,505

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

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	Note	2018	2017	2016
Operating Activities				
Net income/(loss)		$ 378,279	$ 236,998	$ 397,416
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		304,274	250,774	328,964
Asset impairment	5(a)	—	—	301,171
Changes in fair value of derivative instruments	14(b)	(124,266)	(6,184)	105,026
Deferred income tax expense/(recovery)	12	130,304	129,945	(234,847)
Foreign exchange (gain)/loss on debt and working capital	11	58,628	(42,623)	(40,634)
Share-based compensation	13(b)	25,917	22,576	27,014
Translation of U.S. dollar cash held in Canada (gain)/loss	11	(19,630)	10,978	—
Gain on the divestment of assets	4	—	(78,400)	(559,235)
Gain on prepayment of senior notes	7	—	—	(19,270)
Asset retirement obligation expenditures	8	(11,263)	(12,907)	(8,390)
Changes in non-cash operating working capital	17(a)	(3,459)	(35,032)	15,075
Cash flow from operating activities		738,784	476,125	312,290
Financing Activities				
Proceeds from the issuance of shares (net of issue costs)	13(a)	9,138	—	220,410
Dividends	13(a),17(b)	(29,282)	(29,017)	(39,230)
Bank credit facility	7	—	(23,272)	(55,999)
Senior notes	7	(29,044)	(29,084)	(335,400)
Purchase of common shares under Normal Course Issuer Bid	13(a)	(79,027)	—	—
Cash flow from/(used in) financing activities		(128,215)	(81,373)	(210,219)
Investing Activities				
Capital and office expenditures	17(b)	(604,110)	(459,152)	(260,083)
Property and land acquisitions	4	(18,009)	(13,276)	(126,126)
Property divestments	4	(919)	56,196	670,364
Cash flow from/(used in) investing activities		(623,038)	(416,232)	284,155
Effect of exchange rate changes on cash and cash equivalents		29,248	(25,277)	(419)
Change in cash and cash equivalents		16,779	(46,757)	385,807
Cash and cash equivalents, beginning of year		346,548	393,305	7,498
Cash and cash equivalents, end of year		$ 363,327	$ 346,548	$ 393,305

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

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

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

2) SIGNIFICANT ACCOUNTING POLICIES

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

a) Basis of Preparation

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

i. Reporting Currency

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

ii. Use of Estimates

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

iii. Basis of Consolidation

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

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

b) Revenue

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

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

c) Transportation

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

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

d) Oil and Natural Gas Properties

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

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

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and deferred income tax liabilities, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

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

e) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements and computer equipment. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

f) Cash and Cash Equivalents and Restricted Cash

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

In 2017, Enerplus adopted ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash.* As a result of the adoption of ASU 2016-18, restricted cash of $392.0 million at December 31, 2016 has been included in cash and cash equivalents on the Consolidated Statements of Cash Flows, with a corresponding increase to change in cash and cash equivalents. Prior to adoption, changes in restricted cash were included in investing activities. Enerplus' 2016 Consolidated Statement of Cash Flows was restated as required to reflect this change in presentation.

g) Goodwill

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

Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). For the purposes of goodwill impairment testing, Enerplus has two reporting units. The change in goodwill in 2018 and 2017 related to the impact of foreign exchange movements on U.S. dollar denominated goodwill balances. No impairment has been recorded in 2018, 2017 or 2016.

h) Asset Retirement Obligations

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

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

i) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest related to income tax are recognized in income tax expense.

j) Financial Instruments

i. Fair Value Measurements

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

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

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

ii. Non-derivative financial instruments

The carrying amount of cash, accounts receivable, income tax receivable, accounts payable, dividends payable and bank credit facilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of the senior notes are considered a level 2 fair value measurement. The fair value of debt has been disclosed in Note 14.

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

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

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

k) Foreign Currency

i. Foreign currency transactions

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

ii. Foreign operations

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

l) Share-Based Compensation

Enerplus' share-based compensation plans include its equity-settled Restricted Share Unit ("RSU") and Performance Share Unit ("PSU") plans. The Company is authorized to issue up to 3.8% of outstanding common shares from treasury in relation to these plans. Enerplus also has a cash-settled Deferred Share Unit ("DSU") plan.

Enerplus' Stock Option Plan was suspended in 2014 and is now closed.

i. RSU, PSU, and DSU plans

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

Under Enerplus' PSU plan, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual retainer value and they vest upon the director leaving the Board. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All DSU grants are settled in cash.

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

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

ii. Stock options

Enerplus' Stock Option Plan was suspended in 2014 and is now closed. All options outstanding under the plan are fully vested and the expense has been fully recognized.

m) Net Income Per Share

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

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

n) Contingencies

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

o) Accounting Changes and Recent Pronouncements Issued

i. Recently adopted accounting standards

Except for the changes below, the Company has consistently applied the accounting policies to all periods presented in these Consolidated Financial Statements.

Enerplus adopted ASC 606 *Revenue from contracts with customers* effective January 1, 2018 as detailed in Note 2(b). Enerplus used the modified retrospective method to adopt the new standard, with ASC 606 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. The adoption of the new standard had no impact on the Consolidated Financial Statements, with the exception of the additional disclosures which are detailed in Note 9.

Management has applied the following practical expedients as part of the adoption of the standard:

- No changes have been made to the revenue recognized under the previous revenue standard for contracts that were completed during the comparative period; and
- The effect of contract modifications before the beginning of the comparative reporting period have not been evaluated separately. Instead, Enerplus has reflected the aggregated effect of those modifications when identifying the performance obligations, determining the transaction price and allocating the transaction price to the satisfied and unsatisfied performance obligations.

ii. 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 February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduced a lessee accounting model that requires lessees to recognize a right-of-use (ROU) asset and related lease liability on the balance sheet for all leases, including operating leases. The FASB further issued several ASUs in 2018 which provide clarification on implementation of the new standard, technical corrections, improvements and practical expedients that can be applied under certain circumstances. The standard does not apply to oil and gas exploration rights, intangible assets or inventory. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach using either 1) the effective date or 2) the beginning of the earliest comparative period presented in the financial statements as the Company's date of initial adoption. The Company is required to adopt the new standard on January 1, 2019 and will use the effective date as its date of initial application. The standard also provides for certain practical expedients at the date of adoption and for an entity's ongoing accounting. The Company currently expects to elect the practical expedient pertaining to land easements and the short-term lease recognition exemption which allows it to not recognize ROU assets or lease liabilities for leases with a term shorter than twelve months.

The Company has developed an inventory of existing lease agreements, and expects that there will be a material impact on its Consolidated Financial Statements. While the Company continues to finalize the impact of adoption, the most significant effects relate to 1) the recognition of new ROU assets and lease liabilities on the Balance Sheet for office and drilling rig operating leases and 2) providing significant new disclosures about the Company's leasing activities. The Company continues to address system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard. On adoption, we currently expect to recognize lease liabilities ranging from $40.0 million to $45.0 million, with corresponding ROU assets within the same range.

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 to 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, and will be applied prospectively. Enerplus does not expect to early adopt the standard. The amended standard may affect goodwill impairment tests post the adoption date, the impact of which is not known.

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815),* making more hedging strategies eligible for hedge accounting. The new guidance is effective January 1, 2019, and will be applied prospectively. Hedge accounting continues to be an elective accounting policy choice. Enerplus does not currently apply hedge accounting, and therefore does not expect this ASU to have a material impact to its Consolidated Financial Statements.

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2018	December 31, 2017
Accrued revenue	$ 118,821	$ 102,051
Accounts receivable – trade	30,252	30,787
Allowance for doubtful accounts	(3,867)	(3,452)
Total accounts receivable, net of allowance for doubtful accounts	$ 145,206	$ 129,386

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

As at 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

As at December 31, 2017 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties[1]	$ 13,622,266	$ (12,732,299)	$ 889,967
Other capital assets	107,582	(97,518)	10,064
Total PP&E	$ 13,729,848	$ (12,829,817)	$ 900,031

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

Acquisitions:

For the years ended December 31, 2018 and 2017, Enerplus acquired property and land totaling $25.8 million, and $13.3 million, respectively.

Divestments:

For the years ended December 31, 2018 and 2017, Enerplus disposed of properties for proceeds of $6.9 million and $56.2 million, respectively. Certain asset divestments may result in gains if the divestments cause a significant alteration in the relationship between the cost centre's capitalized costs and proved reserves. During 2018, Enerplus did not recognize any gains on asset divestments (2017 – $78.4 million, 2016 – $559.2 million).

5) IMPAIRMENT

a) Impairment of PP&E

There was no impairment recorded for the years ended December 31, 2018 and 2017. The $301.2 million impairment for the year ended December 31, 2016 was due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2018, 2017 and 2016:

Period	WTI Crude Oil US$/bbl	Exchange Rate US$/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
2018	$ 65.56	1.28	$ 69.58	$ 3.10	$ 1.67
2017	51.34	1.30	63.57	2.98	2.32
2016	42.75	1.32	52.26	2.49	2.17

b) Goodwill Impairment

Goodwill is tested for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

There were no additions or impairments to goodwill for the year ended December 31, 2018 or the comparative years.

6) ACCOUNTS PAYABLE

($ thousands)	December 31, 2018	December 31, 2017
Accrued payables	$ 115,388	$ 96,743
Accounts payable – trade	174,657	117,235
Total accounts payable	$ 290,045	$ 213,978

7) DEBT

($ thousands)	December 31, 2018	December 31, 2017
Current:		
Senior notes	$ 60,001	$ 27,656
Long-term:		
Bank credit facility	$ —	$ —
Senior notes	636,849	644,723
Total debt	$ 696,850	$ 672,379

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, $800 million bank credit facility that matures on October 31, 2021. Drawn fees range between 125 and 315 basis points over bankers' acceptance rates. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility or repay the entire balance at the end of the term. At December 31, 2018, Enerplus was undrawn on the facility (December 31, 2017 – undrawn). During 2018, a fee of $0.4 million (2017 – $0.5 million, 2016 – $0.7 million) was paid to extend the facility.

Senior Notes

During 2018 and 2017, Enerplus made its first and second US$22 million principal repayments on its 2009 senior notes. During 2016, Enerplus repurchased US$267 million in outstanding senior notes at a discount, resulting in gains of $19.3 million.

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

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 143,189
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	27,274
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	406,383
June 18, 2009	June 18 and Dec 18	3 equal annual installments beginning June 18, 2019 - 2021	7.97%	US$225,000	US$66,000	90,004
					Total carrying value	$ 696,850

8) ASSET RETIREMENT OBLIGATION

($ thousands)	December 31, 2018	December 31, 2017
Balance, beginning of year	$ 117,736	$ 181,700
Change in estimates	16,755	13,064
Property acquisition and development activity	1,565	1,322
Divestments	(4,585)	(72,306)
Settlements	(11,263)	(12,907)
Accretion expense	5,904	6,863
Balance, end of year	$ 126,112	$ 117,736

Enerplus has estimated the present value of its asset retirement obligation to be $126.1 million at December 31, 2018 based on a total undiscounted liability of $343.9 million (December 31, 2017 – $117.7 million and $318.8 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.59% and inflation rate of 1.8% (December 31, 2017 – 5.73% and 1.8%, respectively). The majority of Enerplus' asset retirement obligation expenditures are expected to be incurred between 2025 and 2055.

9) OIL AND NATURAL GAS SALES

($ thousands)	2018	2017	2016
Oil and natural gas sales	$ 1,610,899	$ 1,141,770	$ 882,126
Royalties(1)	(318,163)	(221,077)	(159,394)
Oil and natural gas sales, net of royalties	$ 1,292,736	$ 920,693	$ 722,732

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

Oil and natural gas revenue by country and by product for the year ended December 31, 2018 is as follows:

Year ended December 31, 2018 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 198,263	$ 148,949	$ 32,109	$ 14,075	$ 3,130
United States	1,094,473	834,146	236,825	23,502	—
Total	$ 1,292,736	$ 983,095	$ 268,934	$ 37,577	$ 3,130

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

Enerplus sells the majority of its production pursuant to variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, natural gas liquids or natural gas to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, and any variability in revenue relates to the Company's ability to deliver product. As a result, revenue is allocated to the production delivered in the period.

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2018	2017	2016
General and administrative expense	$ 49,943	$ 50,544	$ 59,773
Share-based compensation expense(1)	25,840	23,757	26,546
General and administrative expense	$ 75,783	$ 74,301	$ 86,319

(1) Includes cash and non-cash share-based compensation.

11) FOREIGN EXCHANGE

($ thousands)	2018	2017	2016
Realized:			
Foreign exchange (gain)/loss	$ 523	$ 1,495	$ 108
Translation of U.S. dollar cash held in Canada (gain)/loss	(19,630)	10,978	—
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	58,628	(42,623)	(40,634)
Foreign exchange (gain)/loss	$ 39,521	$ (30,150)	$ (40,526)

12) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2018	2017	2016
Current tax expense/(recovery)			
Canada	$ (400)	$ (407)	$ (661)
United States	(26,693)	(47,550)	(1,690)
Current tax expense/(recovery)	(27,093)	(47,957)	(2,351)
Deferred tax expense/(recovery)			
Canada	$ 3,915	$ (17,127)	$ (23,714)
United States	126,389	147,072	(211,133)
Deferred tax expense/(recovery)	130,304	129,945	(234,847)
Income tax expense/(recovery)	$ 103,211	$ 81,988	$ (237,198)

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

($ thousands)	2018	2017	2016
Income/(loss) before taxes			
Canada	$ 104,204	$ 146,953	$ 121,257
United States	377,286	172,033	38,961
Total income/(loss) before taxes	481,490	318,986	160,218
Canadian statutory rate	27.00%	27.00%	27.00%
Expected income tax expense/(recovery)	$ 130,002	$ 86,126	$ 43,259
Impact on taxes resulting from:			
Foreign and statutory rate differences	$ (23,859)	$ 157,320	$ (12,826)
Share-based compensation	(18,102)	5,067	6,611
Non-taxable capital (gains)/losses	7,254	(6,337)	(6,478)
Change in valuation allowance	6,292	(162,992)	(266,896)
Other	1,624	2,804	(868)
Income tax expense/(recovery)	$ 103,211	$ 81,988	$ (237,198)

The deferred income tax asset consists of the following:

As at December 31 ($ thousands)	2018	2017
Deferred income tax liabilities		
Property, plant and equipment	$ (46,284)	$ —
Derivative financial instruments	(24,184)	—
Total deferred income tax liabilities	(70,468)	—
Deferred income tax assets		
Property, plant and equipment	$ 60,665	$ 132,879
Tax loss carry-forwards and other credits	429,651	397,081
Capital loss carryforwards and other capital items	188,409	181,334
Asset retirement obligation	33,935	31,677
Derivative financial instruments	—	8,795
Other assets	14,099	3,046
Deferred income tax asset before valuation allowance	726,759	754,812
Valuation allowance	(191,167)	(184,875)
Deferred income tax assets, net	535,592	569,937
Total deferred income tax asset	$ 465,124	$ 569,937

As of December 31, 2018, $27.2 million was reclassified from deferred income tax asset to income tax receivable for the AMT refund expected to be realized in 2019 (December 31, 2017 – $50.1 million).

Loss carry-forwards and tax credits available for tax reporting purposes:

As at December 31 ($ thousands)	2018	Expiration Date
Canada		
Capital losses	$ 1,226,000	Indefinite
Non-capital losses	410,000	2028-2038
United States		
Net operating losses – prior to 2018	$ 933,000	2030-2037
Net operating losses – 2018 and thereafter	119,000	Indefinite
Alternative minimum tax credits	58,000	Recoverable 2019-2021

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

($ thousands)	2018	2017	2016
Balance, beginning of year	$ 13,300	$ 13,300	$ 15,100
Settlements	—	—	(1,800)
Balance, end of year	$ 13,300	$ 13,300	$ 13,300

If recognized, all of Enerplus’ unrecognized tax benefits as at December 31, 2018 would affect Enerplus’ effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

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

Jurisdiction	Taxation Years
Canada – Federal & Provincial	2013-2018
United States – Federal & State	2015-2018

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

13) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized: unlimited number of common shares Issued: (thousands)	2018 Shares	2018 Amount	2017 Shares	2017 Amount	2016 Shares	2016 Amount
Balance, beginning of year	242,129	$ 3,386,946	240,483	$ 3,365,962	206,539	$ 3,133,524
Issued for cash:						
Purchase of common shares under Normal Course Issuer Bid	(5,925)	(82,596)	—	—	—	—
Stock Option Plan	668	9,138	—	—	—	—
Public offering	—	—	—	—	33,350	230,115
Share issue costs (net of tax of $2,621)	—	—	—	—	—	(7,084)
Non-cash:						
Share-based compensation – settled	2,539	23,389	1,646	20,984	594	9,407
Stock Option Plan – exercised	—	731	—	—	—	—
Balance, end of year	239,411	$ 3,337,608	242,129	$ 3,386,946	240,483	$ 3,365,962

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

For the year ended December 31, 2018, Enerplus declared dividends of $0.12 per weighted average common share totaling $29.3 million (December 31, 2017 – $0.12 per share and $29.0 million, December 31, 2016 – $0.16 per share and $35.4 million).

On March 21, 2018, Enerplus announced the acceptance of its Normal Course Issuer Bid ("NCIB") 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, the Company was permitted to repurchase for cancellation up to 17,095,598 common shares over a period of twelve months commencing on March 26, 2018. 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. For the year ended December 31, 2018, the Company repurchased 5,925,084 common shares under the NCIB at an average price of $13.33 per share, for total consideration of $79.0 million. Of the amount paid, $82.6 million was charged to share capital and $3.6 million was credited to accumulated deficit.

Subsequent to the year, and up to February 20, 2019, the Company repurchased an additional 586,953 common shares under the NCIB at an average price of $11.40 per share, for consideration of $6.7 million. The Company also received approval from the Board of Directors to renew the NCIB upon expiry of the existing term on March 25, 2019, subject to approval by the TSX. The proposed renewal will be for 7% of public float (within the meaning under the TSX rules) consistent with the current bid.

b) Share-based Compensation

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

($ thousands)	2018	2017	2016
Cash:			
Long-term incentive plans expense	$ 133	$ 997	$ 3,114
Non-Cash:			
Long-term incentive plans expense	25,917	22,576	26,951
Equity swap (gain)/loss	(210)	184	(3,582)
Stock option plan expense	—	—	63
Share-based compensation expense	$ 25,840	$ 23,757	$ 26,546

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

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Deferred Share Unit ("DSU") activity for the twelve months ended December 31, 2018:

For the year ended December 31, 2018	Cash-settled LTI Plans	Equity-settled LTI Plans		Total
(thousands of units)	DSU	PSU[(1)]	RSU	
Balance, beginning of year	368	2,713	2,109	5,190
Granted	78	735	809	1,622
Vested	(55)	(2,071)	(1,080)	(3,206)
Forfeited	—	(6)	(85)	(91)
Balance, end of year	391	1,371	1,753	3,515

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

Cash-settled LTI Plans

For the year ended December 31, 2018, the Company made cash payments of $0.5 million related to its cash-settled plans (2017 – $0.1 million, 2016 – $2.7 million).

The 2016 PSU's which vested in December 2018 were cash settled in January 2019, resulting in $30.6 million being recorded to Accounts Payable and Paid-in Capital on the Consolidated Balance Sheets at December 31, 2018.

As of December 31, 2018, a liability of $4.1 million (December 31, 2017 – $4.5 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

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

At December 31, 2018 ($ thousands, except for years)	PSU[(1)]	RSU	Total
Cumulative recognized share-based compensation expense	$ 17,042	$ 12,765	$ 29,807
Unrecognized share-based compensation expense	15,131	5,429	20,560
Fair value	$ 32,173	$ 18,194	$ 50,367
Weighted-average remaining contractual term (years)	1.8	1.4	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

At December 31, 2018, all stock options are fully vested and all non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the year ended December 31, 2018:

Year ended December 31, 2018	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	5,486	$ 18.25
Exercised	(668)	13.66
Forfeited	(49)	21.17
Expired	(638)	30.20
Options outstanding and exercisable, end of year	4,131	$ 17.12

At December 31, 2018, 4,130,921 options were exercisable at a weighted average exercise price of $17.12 with a weighted average remaining contractual term of 0.8 years, giving an aggregate intrinsic value of nil (December 31, 2017 – nil, December 31, 2016 – nil). The intrinsic value of options exercised during the year ended December 31, 2018 was $1.9 million (December 31, 2017 – nil, December 31, 2016 – nil).

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

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

(thousands, except per share amounts)	2018	2017	2016
Net income/(loss)	$ 378,279	$ 236,998	$ 397,416
Weighted average shares outstanding – Basic	244,076	241,929	226,530
Dilutive impact of share-based compensation	3,185	5,945	4,763
Weighted average shares outstanding – Diluted	247,261	247,874	231,293
Net income/(loss) per share			
Basic	$ 1.55	$ 0.98	$ 1.75
Diluted	$ 1.53	$ 0.96	$ 1.72

14) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2018, senior notes had a carrying value of $696.9 million and a fair value of $695.4 million (December 31, 2017 – $672.4 million and $687.2 million, respectively).

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

b) Derivative Financial Instruments

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

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

Gain/(Loss) ($ thousands)	2018	2017	2016	Income Statement Presentation
Equity Swaps	$ 210	$ (184)	$ 3,582	G&A expense
Electricity Swaps	—	639	1,135	Operating expense
Commodity Derivative Instruments:				
Oil	114,822	(5,445)	(96,238)	Commodity derivative
Gas	9,234	11,174	(13,505)	instruments
Total Unrealized Gain/(Loss)	$ 124,266	$ 6,184	$ (105,026)	

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

($ thousands)	2018	2017	2016
Change in fair value gain/(loss)	$ 124,056	$ 5,729	$ (109,743)
Net realized cash gain/(loss)	(35,824)	8,581	80,346
Commodity derivative instruments gain/(loss)	$ 88,232	$ 14,310	$ (29,397)

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

	December 31, 2018			December 31, 2017		
	Assets		Liabilities	Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Current	Current	Long-term
Equity Swaps	$ —	$ —	$ 1,909	$ —	$ 2,119	$ —
Commodity Derivative Instruments:						
Oil	48,314	32,220	—	2,142	26,523	9,907
Gas	10,944	—	—	1,710	—	—
Total	$ 59,258	$ 32,220	$ 1,909	$ 3,852	$ 28,642	$ 9,907

c) Risk Management

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

i) Market Risk

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

Commodity Price Risk:

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

The following tables summarize Enerplus' price risk management positions at February 20, 2019:

Crude Oil Instruments:

Instrument Type(1)(2)	bbls/day	US$/bbl
Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	17,000	54.12
WTI Sold Call	17,000	64.12
WTI Sold Put	17,000	44.28
WCS Differential Swap	1,500	(14.17)
Apr 1, 2019 – Jun 30, 2019		
WTI Purchased Put	23,500	54.59
WTI Sold Call	23,500	65.52
WTI Sold Put	23,500	44.50
WCS Differential Swap	1,500	(14.83)
WTI - Brent Swap	2,700	(8.10)
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)
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 Call	16,000	72.50
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 as the weighted average price/bbl before premiums.
(2) The total average deferred premium on three way collars is US$1.61/bbl from January 1, 2019 to December 31, 2020.

Natural Gas Instruments:

Instrument Type[1]	MMcf/day	US$/Mcf
Jan 1, 2019 – Mar 31, 2019		
NYMEX Swap	50.0	4.23
NYMEX Purchased Put	50.0	3.80
NYMEX Sold Call	50.0	6.01
Apr 1, 2019 – Oct 31, 2019		
NYMEX Swap	70.0	2.85

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

Enerplus has physical sales contracts in place for approximately 16,000 bbls/day of 2019 Bakken production with fixed differentials averaging approximately US$3.00/bbl below WTI.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a significant portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At December 31, 2018, Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

At December 31, 2018, all of Enerplus' debt was based on fixed interest rates, and Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 13. Enerplus has entered into various equity swaps maturing in 2019 and has effectively fixed the future settlement cost on 195,000 shares at a weighted average price of $20.60 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 December 31, 2018, approximately 80% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2018 was $3.9 million (December 31, 2017 – $3.5 million).

iii) Liquidity Risk & Capital Management

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

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

At December 31, 2018, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

15) COMMITMENTS AND CONTINGENCIES

a) Commitments

Enerplus has the following minimum annual commitments:

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2019	2020	2021	2022	2023	Thereafter
Senior notes[1]	$ 696,850	$ 60,001	$ 111,278	$ 111,278	$ 109,914	$ 108,551	$ 195,828
Transportation commitments[2]	367,646	36,817	37,951	34,102	31,410	30,317	197,049
Processing commitments	16,174	3,506	3,174	1,519	1,519	1,519	4,937
Drilling and completions	51,433	20,005	20,005	11,423	—	—	—
Office lease commitments	73,746	9,421	10,662	11,146	11,328	11,453	19,736
Sublease recoveries	(15,405)	(3,151)	(3,401)	(3,198)	(2,434)	(1,720)	(1,501)
Net office lease commitments[5]	58,341	6,270	7,261	7,948	8,894	9,733	18,235
Total commitments[3][4]	$ 1,190,444	$ 126,599	$ 179,669	$ 166,270	$ 151,737	$ 150,120	$ 416,049

(1) Interest payments have not been included.
(2) Includes additional firm transportation commitments executed subsequent to year-end.
(3) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(4) US$ commitments have been converted to CDN$ using the December 31, 2018 foreign exchange rate of 1.3637.
(5) Net office lease payments in 2018 were $8.0 million (2017 – $9.7 million, 2016 – $10.5 million).

b) Contingencies

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

16) GEOGRAPHICAL INFORMATION

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

As at and for the year ended December 31, 2017 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 227,031	$ 693,662	$ 920,693
Depletion, depreciation and accretion	89,936	160,838	250,774
Property, plant and equipment	246,604	653,427	900,031
Goodwill	451,121	187,757	638,878
Long term income tax receivable	—	50,108	50,108

As at and for the year ended December 31, 2016 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 233,391	$ 489,341	$ 722,732
Depletion, depreciation and accretion	126,062	202,902	328,964
Property, plant and equipment	304,048	434,382	738,430
Goodwill	451,121	200,542	651,663
Long term income tax receivable	—	—	—

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2018	December 31, 2017	December 31, 2016
Accounts receivable	$ (45,385)	$ (66,860)	$ 16,982
Other current assets	(3,026)	(154)	2,154
Accounts payable	44,952	31,982	(4,061)
	$ (3,459)	$ (35,032)	$ 15,075

b) Changes in Other Non-Cash Working Capital

($ thousands)	December 31, 2018	December 31, 2017	December 31, 2016
Non-cash financing activities[1]	$ (26)	$ 16	$ (3,791)
Non-cash investing activities[2]	$ (3,753)	$ 1,523	$ (49,472)

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

c) Other

($ thousands)	December 31, 2018	December 31, 2017	December 31, 2016
Income taxes paid/(received)	$ (481)	$ 2,640	$ (21,244)
Interest paid	$ 36,161	$ 38,149	$ 48,545

5 YEAR DETAILED STATISTICAL REVIEW

	2018	2017	2016	2015	2014
Daily Production Volumes(1)					
Crude oil (bbls/day)	45,424	36,935	38,353	41,639	40,208
Natural gas liquids (bbls/day)	4,486	3,858	4,903	4,763	3,565
Natural gas (Mcf/day)	259,837	263,506	299,214	360,733	356,142
BOE per day	93,216	84,711	93,125	106,524	103,130
Drilling Activity (net wells)	61	46	25	46	88
Average Benchmark Pricing					
WTI crude oil (US$ per bbl)	$ 64.77	$ 50.95	$ 43.32	$ 48.80	$ 93.00
AECO natural gas - monthly (per Mcf)	1.53	2.43	2.09	2.77	4.42
NYMEX natural gas - last day (US$ per Mcf)	3.09	3.11	2.46	2.66	4.41
US/CDN exchange rate (average)	1.30	1.30	1.32	1.28	1.10
Realized Pricing(2)					
Crude oil (per bbl)	$ 74.59	$ 58.69	$ 44.84	$ 48.43	$ 86.28
Natural gas liquids(per bbl)	28.31	30.01	15.29	18.06	51.72
Natural gas (per Mcf)	3.42	3.21	2.06	2.15	3.94
Financial ($ thousands, except per share amounts)					
Oil and natural gas sales(2)	$ 1,610,899	$ 1,141,770	$ 882,126	$ 1,052,381	$ 1,849,312
Cash flow from operating activities	738,784	476,125	312,290	465,336	787,197
Adjusted funds flow(3)	753,506	524,064	305,605	493,101	859,020
Cash and stock dividends to Shareholders	29,256	29,033	35,439	131,955	221,098
Per share	0.12	0.12	0.16	0.64	1.08
Capital spending	593,876	458,015	209,135	493,403	811,026
Property and land acquisitions	25,840	13,276	126,126	9,552	18,491
Property divestitures	6,912	56,196	670,364	286,614	203,576
Total net capital expenditures(4)	619,285	417,755	(333,627)	220,813	632,883
Total assets	3,118,300	2,645,832	2,638,850	2,581,234	4,031,492
Total debt net of cash and restricted cash	333,523	325,831	375,520	1,216,184	1,134,894
Adjusted payout ratio(3)(5)	84%	93%	80%	128%	118%
Net debt to adjusted funds flow ratio	0.4x	0.6x	1.2x	2.5x	1.3x
Royalties and production taxes rate	25%	24%	22%	21%	23%
Oil and Gas Economics per BOE					
Oil & natural gas sales(2)	$ 47.35	$ 36.93	$ 25.88	$ 27.07	$ 49.13
Transportation costs	(3.63)	(3.60)	(3.14)	(2.95)	(2.69)
Royalties and production taxes	(11.92)	(8.91)	(5.77)	(5.63)	(10.75)
Cash gains/(losses) on commodity derivative instruments	(1.05)	0.28	2.36	7.40	0.09
Average realized price, net	30.75	24.70	19.33	25.89	35.78
Cash operating expenses	(7.00)	(6.39)	(7.31)	(8.75)	(9.23)
Operating netback, after hedging	23.75	18.31	12.02	17.14	26.55
Cash general and administrative expenses	(1.48)	(1.66)	(1.84)	(2.11)	(2.19)
Cash interest, foreign exchange and other expenses	(0.92)	(1.24)	(1.28)	(2.78)	(1.42)
Current income tax recovery/(expense)	0.80	1.55	0.07	0.43	(0.12)
Adjusted funds flow(3)	$ 22.15	$ 16.96	$ 8.97	$ 12.68	$ 22.82
Trading Information					
Canadian trading summary(6)					
High	$ 18.04	$ 13.35	$ 13.55	$ 16.09	$ 27.05
Low	$ 9.65	$ 8.97	$ 2.68	$ 4.24	$ 9.02
Close	$ 10.62	$ 12.31	$ 12.74	$ 4.75	$ 11.19
Volume (in 000's)	533,666	520,460	688,243	550,742	360,805
U.S. trading summary(7)					
High	$ 13.87	$ 10.21	$ 10.33	$ 13.16	$ 25.37
Low	$ 6.84	$ 6.52	$ 1.84	$ 3.01	$ 7.75
Close	$ 7.76	$ 9.79	$ 9.48	$ 3.42	$ 9.60
Volume (in 000's)	245,759	261,215	347,941	382,094	203,965
Weighted average number of shares outstanding (basic)(8)	244,076	241,929	226,530	206,205	204,510
Number of shares outstanding at December 31(8)	239,411	242,129	240,483	206,539	205,732

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

($ thousands)	2018	2017	2016	2015	2014
Reserves (1)					
Proved Reserves					
Crude oil (Mbbls)	137,348	122,543	119,419	131,778	127,007
NGLs (Mbbls)	13,783	13,000	11,825	10,704	8,137
Conventional natural gas (MMcf)	31,007	55,992	95,769	183,564	331,709
Shale gas (MMcf)	849,063	803,018	726,614	625,081	564,583
MBOE	297,809	278,711	268,308	277,255	284,525
Probable Reserves					
Crude oil (Mbbls)	70,870	68,479	56,798	58,222	73,424
NGLs (Mbbls)	7,277	7,752	6,273	4,993	4,662
Conventional natural gas (MMcf)	10,129	21,289	30,521	53,802	124,721
Shale gas (MMcf)	300,449	233,742	276,169	338,288	275,357
MBOE	129,909	118,737	114,186	128,563	144,766
Proved Plus Probable Reserves					
Crude oil (Mbbls)	208,215	191,022	176,216	189,999	200,431
NGLs (Mbbls)	21,060	20,752	18,098	15,697	12,798
Conventional natural gas (MMcf)	41,137	77,281	126,290	237,366	456,430
Shale gas (MMcf)	1,149,511	1,036,760	1,002,783	963,368	839,940
MBOE	427,718	397,448	382,493	405,818	429,291
Reserves Life Index(2)					
Proved (years)	8.4	9.2	9.0	9.0	7.8
Proved plus probable (years)	11.3	12.6	12.3	12.2	10.7
Finding & Development Costs and Finding, Development & Acquisition Costs(3)					
Proved Reserves					
Finding & Development Costs					
Capital expenditures	$ 593.8	$ 458.0	$ 209.1	$ 493.4	$ 811.0
Net change in future development costs	$ 309.3	$ 114.0	$ (124.4)	$ 210.0	$ 13.8
Gross reserves additions (MMBOE)	54.1	50.5	47.2	50.7	69.1
F&D costs ($/BOE)	**$ 16.69**	**$ 11.32**	**$ 1.79**	**$ 13.88**	**$ 11.94**
Finding, Development & Acquisition Costs					
Capital expenditures and net acquisitions	$ 612.7	$ 415.1	$ (335.1)	$ 216.2	$ 625.9
Net change in future development costs	$ 308.3	$ 96.7	$ (202.1)	$ 139.7	$ 4.9
Gross reserves additions (MMBOE)	52.9	41.0	24.7	31.1	60.9
FD&A costs ($/BOE)	**$ 17.42**	**$ 12.48**	**$ (21.74)**	**$ 11.44**	**$ 10.36**
Proved Plus Probable Reserves					
Finding & Development Costs					
Capital expenditures	$ 593.8	$ 458.0	$ 209.1	$ 493.4	$ 811.0
Net change in future development costs	$ 309.1	$ 102.8	$ (4.0)	$ (142.2)	$ (71.3)
Gross reserves additions (MMBOE)	65.7	58.0	42.6	41.6	75.5
F&D costs ($/BOE)	**$ 13.74**	**$ 9.68**	**$ 4.82**	**$ 8.44**	**$ 9.80**
Finding, Development & Acquisition Costs					
Capital expenditures and net acquisitions	$ 612.7	$ 415.1	$ (335.1)	$ 216.2	$ 625.9
Net change in future development costs	$ 308.1	$ 85.1	$ (94.5)	$ (212.5)	$ (59.2)
Gross reserves additions (MMBOE)	64.1	45.6	10.3	14.9	65.8
FD&A costs ($/BOE)	**$ 14.37**	**$ 10.98**	**$ (41.60)**	**$ 0.25**	**$ 8.62**

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

NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserves engineers, McDaniel and Netherland, Sewell & Associates, Inc. at year-end, plus the estimated value of our undeveloped acreage, less asset retirement obligations, total debt net of cash and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of contingent resources. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a significant increase in our booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value (Forecast Prices and Costs at December 31, 2018)

($ millions, except per share amounts)	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$ 10,113	$ 6,405	$ 4,582	$ 3,524
Undeveloped acreage (2018 year end)(1)	65	65	65	65
Asset retirement obligations(2)	(117)	(100)	(48)	(32)
Total debt net of cash	(334)	(334)	(334)	(334)
Net working capital(3)	-	-	-	-
Net Asset Value	$ 9,727	$ 6,036	$ 4,265	$ 3,223
Net Asset Value per Share(4)	$ 40.63	$ 25.21	$ 17.81	$ 13.46

(1) U.S. Acreage is carried at historical acquisition cost. Canadian acreage in S.E. Saskatchewan is carried at market price. All other acreage is valued at a nominal value of $25/acre. U.S. values were converted to Canadian dollars at the year end US/CDN exchange rate of 1.3637.

(2) Asset retirement obligations ("ARO") may not equal the balance sheet as a portion of ARO costs are already reflected in the present value of 2P reserves, and the discount rates applied may differ.

(3) Net working capital includes current derivative financial assets and liabilities, income tax receivable and excludes the current portion of long-term debt and cash.

(4) Based on 239,411,102 shares outstanding at December 31, 2018.

AECO a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices

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

Bcf billion cubic feet

BOE(1) barrels of oil equivalent

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

LTI long-term incentive

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

MMcf million cubic feet

MMBOE million barrels of oil equivalent

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

NCIB Normal Course Issuer Bid

NGL natural gas liquid

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

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

2P Reserves proved plus probable reserves

RLI reserves life index

SBC share based compensation

SEC United States Securities and Exchange Commission

TGP Z4 300L Price benchmark for Marcellus natural gas delivered into the 300 Leg within Zone 4 of the Tennessee Gas Pipeline system between Tioga and Susquehanna Counties in Pennsylvania

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

DAPL Dakota Access Pipeline

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

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

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

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

DEFINTIONS

Contingent Resources Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as “contingent resources” the estimated discovered recoverable quantities associated with a project in the early project stage. “Economic” contingent resources are those resources that are economically recoverable based on the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd., and Sproule Associates Limited as of January 1, 2019.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

BOARD OF DIRECTORS

Elliott Pew[(1)(2)]

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[(3)(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

Glen D. Roane[(4)(5)]

Corporate Director
Canmore, Alberta

Jeffrey W. Sheets[(5)(9)(11)]

Corporate Director
Houston, Texas

Sheldon B. Steeves[(8)(11)]

Corporate Director
Calgary, Alberta

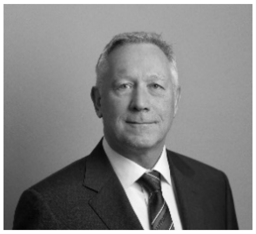
(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(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 & Engineering

Nathan D. Fisher

Vice President, U.S.
Development &
Geosciences

Daniel J. Fitzgerald

Vice President, Business
Development

John E. Hoffman

Vice President,
Canadian Operations

David A. McCoy

Vice President, General
Counsel & Corporate
Secretary

Edward L. McLaughlin

President,
U.S. Operations

Shaina B. Morihira

Vice President, Finance

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
KPMG LLP
Calgary, Alberta

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

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

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

Netherland, Sewell & Associates, Inc.
Dallas, Texas

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

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

Telephone: 720.279.5500
Fax: 720.279.5550

Annual Meeting
Shareholders are encouraged to attend the Annual Meeting being held on:

Thursday, May 9, 2019
1:00 p.m., MT
Bankers Hall Auditorium
P3 level, Bankers Hall
315 – 8th Avenue SW
Calgary, Alberta

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