Cona Resources Ltd.

Management's Discussion and Analysis

For the Years Ended December 31, 2017 and 2016

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Cona Resources Ltd. (formerly Northern Blizzard Resources Inc.) for the year ended December 31, 2017. This information is provided as of March 6, 2018. In this MD&A, references to ''Cona", the ''Company'', ''we'', ''us'' and ''our'' and similar terms refer to Cona Resources Ltd. and its subsidiaries on a consolidated basis, except where the context requires otherwise. Other terms and abbreviations used in this MD&A have the meanings set forth under the heading "Advisories – Abbreviations". This MD&A should be read in conjunction with the consolidated financial statements for the years ended December 31, 2017 and 2016 as well as Cona's annual information form. This MD&A should also be read in conjunction with the information found under the headings "Advisories – Non-IFRS Financial Measures" and "Forward-Looking Statements" included at the end of this MD&A. All currency is expressed in Canadian dollars unless otherwise indicated. Additional information about Cona is available on Cona's website at www.conaresources.com or on SEDAR at www.sedar.com.

Advisories and abbreviations are located at the end of this document.

DESCRIPTION OF THE COMPANY

Cona Resources Ltd. is incorporated under the *Business Corporations Act* (Alberta). On July 12, 2017, the Company changed its name to Cona Resources Ltd. from Northern Blizzard Resources Inc. and the Company's stock symbol on the Toronto Stock Exchange was changed to "CONA" from "NBZ".

Cona is a Canadian crude oil production and development company focused on maximizing free cash flow from its low decline oil resource base. The Company's operations, infrastructure and concentrated land position are focused in southwest Saskatchewan.

Cona's strategic objective is to utilize its free cash flow generating assets to provide an attractive risk adjusted total return to shareholders. Cona expects to realize its strategic objective through the following key elements of its business strategy:

1) Development of Cona's low decline production base by evaluating and implementing enhanced oil recovery opportunities;

2) Strengthen Cona's balance sheet and manage debt through free cash flow generation and divestment of non-core assets; and

3) Assessing external opportunities for growth.

CHANGE OF CONTROL

As at December 31, 2017, the significant shareholders of the Company were affiliates of Waterous Energy Fund ("WEF").

On May 11, 2017, WEF, through its affiliates WEF GP (International) Ltd., the general partner of Waterous Energy Fund (International) L.P., and WEF GP (Canadian) Corp., the general partner of Waterous Energy Fund (Canadian) L.P., acquired the common shares of the Company held by NGP IX Northern Blizzard S.àr.l. ("NGP IX") and R/C Canada Coöperatief U.A. ("R/C Canada"). The purchase represented approximately 67% of the Company's outstanding shares.

The acquisition of the shares was a change of control of the Company as defined in the indenture dated January 29, 2014 (the "Indenture") governing the 7.25% senior unsecured notes due 2022 ("Senior Notes"). The Indenture included a provision that in the event of a change of control, the Company must offer to purchase all outstanding Senior Notes. Following a tender offer announced on June 9, 2017, Cona repurchased all of the outstanding Senior Notes during the third quarter of 2017.

The acquisition of the shares also triggered a provision in the Company's Compensation Award Incentive Plan (the "Incentive Plan") whereby the awards outstanding under the Incentive Plan (the "Awards") became payable. The Company settled the value of the Awards that became payable with cash and common shares soon after the change of control on May 11, 2017.

GUIDANCE

The guidance provided is based on a number of material assumptions and factors set out below and under the heading "Forward-Looking Statements". This financial outlook is included to provide readers with an understanding of the Company's operations for 2017 and 2018. Readers are cautioned that the information may not be appropriate for other purposes. The actual results of Cona's operations for the corresponding period will vary from the financial outlook and such variations may be material. See "Forward-Looking Statements" for a discussion of the risks that could cause actual results to vary. This summary has been approved by management as of the date of this MD&A.

The table below provides a comparison of Cona's operational guidance and actual results for the year ended December 31, 2017, as well as a summary of Cona's prior and revised operational guidance for the year ended December 31, 2018.

	2017			2018	
	Guidance[1]	**Actual**	**Variance (%)**	**Prior Guidance[1]**	**Revised Guidance[1]**
Production (boe/d)	**17,400**	17,206	(1)	17,400	**16,300**
Pricing					
WTI (US$/bbl)	**49.60**	50.95	3	53.50	**60.00**
WCS differential (US$/bbl)	**11.75**	11.98	2	13.75	**21.50**
CAD/USD exchange rate	**1.298**	1.298	-	1.280	**1.265**
WCS ($/bbl)	**49.12**	50.54	3	50.88	**48.70**
AECO ($/mcf)	**2.60**	2.16	(17)	2.00	**1.30**
Average realized price ($/boe)[2]	**45.18**	46.22	2	46.84	**42.25**
Expenses					
Average royalty rate (%)	**12**	11	(8)	13	**13**
Operating ($/boe)	**16.50**	17.37	5	17.65	**17.65**
Transportation ($/boe)	**2.20**	2.14	(3)	2.15	**2.05**
General & administrative ($/boe)	**2.04**	2.13	4	2.15	**2.20**
Finance and other ($/boe)	**4.06**	4.09	2	3.85	**4.55**
Change of control costs ($/boe)[3]	**0.70**	0.69	(1)	-	**-**
Funds from operations ($ millions)[4,5]					
Excluding hedging	**94**	94	-	97	**63**
Including hedging	**94**	90	(4)	82	**32**
Funds from operations per boe ($boe)[4,5]					
Excluding hedging	**14.85**	14.94	1	15.20	**10.70**
Including hedging	**14.90**	14.32	(4)	12.90	**5.45**
Capital expenditures ($ millions)	**60**	58	(3)	61.5	**44.5**

Notes:

(1) The 2017 guidance was provided in a news release dated August 14, 2017, the prior 2018 guidance was provided in a news release dated November 14, 2017 and the revised 2018 guidance was provided in a news release dated March 6, 2018. The news releases are available on Cona's website at www.conaresources.com or at www.sedar.com.

(2) Average realized prices are calculated based on oil and natural gas sales net of blending expenses.

(3) Includes termination payments of $4.0 million and other costs of $0.4 million related to the change of control that occurred in May 2017.

(4) Includes costs related to the change of control (see Note 3).

(5) "Funds from operations" and "funds from operations per boe" are non-IFRS financial measures. See discussion under the heading "Non-IFRS Financial Measures".

2017 Actual Results Compared to Guidance

Production for the year ended December 31, 2017 of 17,206 boe/d was 1% lower than guidance of 17,400 boe/d.

Capital expenditures in 2017 were $57.9 million (compared to guidance of $60.0 million), which included the drilling of 70 (67.0 net) wells compared to guidance of 68 (65.6 net) wells.

The average royalty rate for 2017 was lower than annual guidance due to a reduction in freehold production taxes.

Operating expenses of $17.37/boe for the year ended December 31, 2017 were higher than the annual guidance of $16.50/boe mainly due to higher than anticipated surface and downhole maintenance costs

Funds from operations (including hedging) of $14.32/boe for 2017 were slightly lower than the annual guidance of $14.90/boe due to increased operating costs and losses on financial derivative contracts, partially offset by higher realized oil prices.

2018 Guidance

Our revised guidance for 2018, based on a WTI price of US$60.00/bbl and WTI/WCS differential of US$21.50/bbl, includes production of 16,300 boe/d and funds from operations of $32.0 million ($63.0 million excluding hedging) or $0.32 per common share ($0.62 per common share excluding hedging).

Capital expenditures are forecast to be $44.5 million in 2018, which includes drilling 31 gross wells. During the first quarter of 2018, Cona drilled the majority of the wells planned for 2018 including 15 wells at Cactus Lake, 11 wells at Winter and 5 wells at Court.

Cona operates and controls virtually all of our development program, which provides flexibility in our capital expenditures. We will continue to review and evaluate our capital spending program in light of commodity prices and will align spending with the appropriate economic returns.

SELECTED ANNUAL INFORMATION

($000s, except per share figures and unless otherwise noted)	2017	2016	2015
Financial			
Oil and natural gas sales	368,084	308,754	422,305
Funds from operations[1]	89,869	134,980	165,566
Per share – basic	0.87	1.14	1.53
Per share – diluted	0.86	1.11	1.50
Net loss	(86,996)	(196,213)	(124,171)
Per share – basic	(0.85)	(1.66)	(1.15)
Per share – diluted	(0.85)	(1.66)	(1.15)
Total assets	1,187,107	1,475,953	1,703,630
Total long-term financial liabilities	328,586	403,322	383,801
Net debt[1]	332,958	252,348	400,508
Total capital expenditures[2]	57,932	51,445	70,035
Total dispositions	1,698	72,954	-
Dividends declared	14,590	54,397	81,715
Per share – diluted	0.14	0.46	0.76
Weighted average shares outstanding, basic (000s)	102,951	117,955	107,878
Weighted average shares outstanding, diluted (000s)	105,037	121,792	110,231
Shares outstanding, period end (000s)	101,006	123,506	112,790
Operating			
Production			
Heavy oil (bbl/d)	16,953	17,476	18,940
Light oil (bbl/d)	-	538	1,036
Natural gas (mcf/d)	1,520	2,358	5,447
Total (boe/d)	17,206	18,407	20,884
Sales (boe/d)	17,211	18,295	21,020
Netbacks ($/boe)			
Average realized price[3]	46.22	35.09	41.90
Royalties	(4.86)	(3.69)	(4.62)
Production and operating expenses	(17.37)	(15.91)	(16.72)
Transportation expenses	(2.14)	(1.82)	(1.85)
Operating netback[1]	21.85	13.67	18.71
Realized gains (losses) on financial derivative contracts[4]	(0.62)	13.97	8.82
General and administrative expenses	(2.13)	(3.22)	(2.76)
Change of control costs[5]	(0.69)	-	-
Cash finance costs	(3.89)	(4.30)	(4.17)
Other[6]	(0.20)	0.05	0.99
Funds from operations	14.32	20.17	21.59

Notes:

(1) "Funds from operations", "net debt" and "operating netback" are non-IFRS financial measures. See discussion under the heading "Advisories – Non-IFRS Financial Measures".

(2) Total capital expenditures include cash expenditures for property, plant and equipment, intangible assets and property acquisitions. Property dispositions have been excluded.

(3) Cona's risk management strategy includes both physical delivery contracts (fixed price forward sales) and financial derivative contracts. There were physical delivery contracts in effect in 2015 and 2016, the impact of which has been included in the average realized prices in the table above.

(4) Unrealized gains or losses are not included in the determination of funds from operations.

(5) Includes termination payments of $4.0 million and other costs of $0.4 million related to the change of control that occurred in May 2017.

(6) Other includes realized foreign exchange gains (losses) and other income.

SELECTED QUARTERLY INFORMATION

	2017				2016			
($000s, except per share figures and unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
Oil and natural gas sales	99,104	84,839	93,110	91,031	94,072	76,045	81,977	56,660
Funds from operations[1]	27,882	25,347	15,727	20,913	40,179	34,038	33,971	26,792
Per share – basic	0.28	0.25	0.16	0.19	0.33	0.29	0.29	0.23
Per share – diluted	0.27	0.25	0.15	0.18	0.32	0.28	0.28	0.23
Net income (loss)	(108,295)	(6,440)	6,853	20,886	(120,531)	(16,775)	(69,027)	10,120
Per share – basic	(1.07)	(0.06)	0.07	0.19	(0.99)	(0.14)	(0.59)	0.09
Per share – diluted	(1.07)	(0.06)	0.06	0.18	(0.99)	(0.14)	(0.59)	0.09
Total assets	1,187,107	1,279,281	1,327,308	1,352,059	1,475,953	1,611,810	1,608,338	1,672,554
Total long-term financial liabilities	328,586	347,890	2,333	381,129	403,322	384,784	380,506	365,935
Net debt[1]	332,958	344,273	359,350	345,909	252,348	335,912	337,535	360,621
Total capital expenditures[2]	15,446	7,782	13,674	21,030	14,889	22,111	7,523	6,922
Total dispositions	-	1,488	-	210	73,266	-	-	-
Dividends declared	-	2,020	6,060	6,510	12,229	14,347	14,062	13,759
Per share	-	0.02	0.06	0.06	0.10	0.12	0.12	0.12
Weighted average shares outstanding, basic (000s)	101,006	101,006	100,745	109,160	121,914	118,940	116,718	114,208
Weighted average shares outstanding, diluted (000s)	102,575	101,006	103,194	113,539	126,484	122,355	120,350	117,995
Shares outstanding, period end (000s)	101,006	101,006	101,006	101,006	123,506	120,445	117,972	115,494
Operating								
Production								
Heavy oil (bbl/d)	16,556	17,297	16,986	16,974	17,524	16,924	17,209	18,255
Light oil (bbl/d)	-	-	-	-	399	480	570	706
Natural gas (mcf/d)	1,099	1,854	1,762	1,363	2,146	2,159	2,568	2,562
Total (boe/d)	16,739	17,606	17,280	17,201	18,281	17,764	18,207	19,388
Sales (boe/d)	17,193	17,305	17,253	17,090	18,508	17,457	18,269	18,955
Netbacks ($/boe)								
Average realized price[3]	50.03	45.08	46.01	43.68	42.93	38.08	37.68	22.07
Royalties	(5.18)	(4.53)	(5.06)	(4.69)	(4.58)	(4.23)	(4.25)	(1.77)
Production and operating expenses	(17.55)	(17.36)	(18.87)	(15.65)	(15.42)	(17.26)	(16.40)	(14.66)
Transportation expenses	(2.16)	(1.97)	(2.18)	(2.26)	(1.97)	(2.03)	(1.95)	(1.37)
Operating netback[1]	25.14	21.22	19.90	21.08	20.96	14.56	15.08	4.27
Realized gains (losses) on financial derivative contracts	(2.34)	0.83	(0.28)	(0.71)	8.84	13.44	12.58	20.87
General and administrative expenses	(2.14)	(1.90)	(2.13)	(2.37)	(2.76)	(2.87)	(2.79)	(4.43)
Change of control costs[4]	-	-	(2.77)	-	-	-	-	-
Cash finance costs	(3.43)	(3.50)	(4.41)	(4.22)	(3.96)	(4.39)	(4.46)	(4.40)
Other[5]	0.40	(0.74)	(0.29)	(0.18)	0.52	0.47	0.03	(0.79)
Funds from operations	17.63	15.91	10.02	13.60	23.60	21.21	20.44	15.52

Notes:

(1) "Funds from operations", "net debt" and "operating netback" are non-IFRS financial measures. See discussion under the heading "Advisories – Non-IFRS Financial Measures".

(2) Total capital expenditures include cash expenditures for property, plant and equipment, intangible assets and property acquisitions.

(3) Cona's risk management strategy includes both physical delivery contracts (fixed price forward sales) and financial derivative contracts. There were physical delivery contracts in effect for the year ended December 31, 2016, the impact of which is included in the average realized prices in the table above.

(4) Includes termination payments of $4.0 million and other costs of $0.4 million related to the change of control that occurred in May 2017.

(5) Other includes realized foreign exchange gains (losses) and other income.

Over the past eight quarters, oil and natural gas sales have fluctuated predominantly due to changes in oil prices and changes in production volumes.

Funds from operations were impacted primarily by changes in oil and natural gas sales, associated royalties, production and operating expenses and realized gains or losses on financial derivative contracts.

Changes in net income (loss) were driven primarily by funds from operations, share-based compensation expense, unrealized gains or losses on financial derivative contracts, depletion, depreciation, amortization and impairment and unrealized foreign exchange gains or losses.

Capital expenditures fluctuated over the past eight quarters as a result of timing of the Company's development program and spending on facilities projects during the periods.

The following outlines the significant events over the past eight quarters:

During the fourth quarter of 2016, Cona disposed of its Coleville and Smiley properties for total net consideration of $73.3 million. The properties produced approximately 1,200 boe/d at the time of the dispositions. The Company also discontinued its stock dividend program in December 2016.

During the first quarter of 2017, the Company completed an issuer bid, whereby 22,500,000 common shares were purchased at $4.00 per common share for $90.0 million and subsequently cancelled. The common shares purchased represented 18.2% of the then-outstanding common shares of the Company. The issuer bid was funded with cash on hand. After the issuer bid, Cona had 101,005,757 common shares outstanding.

During the second quarter of 2017, affiliates of WEF acquired an aggregate of 67,742,345 common shares, representing approximately 67% of the outstanding common shares, held by NGP IX and R/C Canada. In connection with the change of control, the Company was required to offer to repurchase all of the outstanding Senior Notes and all Awards under the Incentive Plan became payable and were settled for consideration of $14.9 million. The Company also incurred termination payments of $4.0 million in connection with the change of control.

During the third quarter of 2017, Cona repurchased US$269.7 million principal of outstanding Senior Notes from holders. The repurchase of the Senior Notes was financed through the Company's existing revolving credit facility, the Term Loan and cash on hand. The Company also suspended its monthly dividend during the third quarter of 2017 with the last dividend paid on on August 15, 2017.

During the fourth quarter of 2017, Cona classified a number of minor properties as held for sale and recorded an associated impairment charge of $60.6 million. Additionally, as a result of recent property disposition activity with anticipated proceeds lower than carrying values, the Company recorded an impairment charge of $15.0 million attributed to PP&E.

RESULTS OF OPERATIONS

Production

	Three months ended December 31			Years ended December 31		
	2017	2016(2)	% Change	**2017**	2016(2)	% Change
Daily Production						
Heavy oil (bbl/d)(1)	**16,556**	17,524	(6)	**16,953**	17,476	(3)
Light oil (bbl/d)	**-**	399	(100)	**-**	538	(100)
Natural gas (mcf/d)	**1,099**	2,146	(49)	**1,520**	2,358	(36)
Total (boe/d)	**16,739**	18,281	(8)	**17,206**	18,407	(7)
Production Mix						
Heavy oil (%)	**99**	96	3	**99**	95	4
Light oil (%)	**-**	2	(100)	**-**	3	(100)
Natural gas (%)	**1**	2	(50)	**1**	2	(50)

Note:

(1) Oil sales volumes differ from production volumes due to changes in oil inventory. For the three months ended December 31, 2017, oil sales volumes were 454 bbl/d higher (2016 – 227 bbl/d higher) than production volumes. For the year ended December 31, 2017, oil sales volumes were 5 bbl/d higher (2016 – 112 bbl/d lower) than production volumes. See "Netbacks".

(2) In late 2016, Cona sold two properties that contributed 962 boe/d and 1,317 boe/d of total production during the three months and year-ended December 31, 2016, respectively. Cona's light oil production was from the Viking development and was one of the disposed properties.

Cona's operations, infrastructure and concentrated land position are focused in southwest Saskatchewan. During the year ended December 31, 2017, 100% of Cona's production volumes were produced from Saskatchewan (2016 – 100%).

Heavy oil production for the fourth quarter of 2017 decreased 6% to 16,556 bbl/d compared to 17,524 bbl/d for the same period in 2016. The decrease was mainly due to the dispositions at the end of 2016, natural declines on existing production and inclement weather that increased well downtime in late 2017. This was partially offset by production increases resulting from development activity during the prior twelve months.

Natural gas production of 1,099 mcf/d for the fourth quarter of 2017 decreased from 2,146 mcf/d in the last quarter of 2016 primarily due to gas plant outages, property dispositions and natural declines, partially offset by a lower amount of natural gas used internally as lease fuel.

Combined average daily production for the fourth quarter of 2017 decreased 8% to 16,739 boe/d compared to 18,281 boe/d for the same period in 2016. The dispositions at the end of 2016 accounted for 5% of the decrease and the balance was due to the reasons noted above.

Heavy oil production for the year ended December 31, 2017 decreased 3% to 16,953 bbl/d compared to 17,476 bbl/d for the same period in 2016. After adjusting for the dispositions at the end of 2016, heavy oil production increased 1% from the prior period mainly due to development activity during the last 12 months, partially offset by natural declines on existing production.

Natural gas production of 1,520 mcf/d for the year ended December 31, 2017 decreased from 2,358 mcf/d primarily due to property dispositions and natural declines, partially offset by a lower amount of natural gas used internally as lease fuel.

Combined average daily production for the year ended December 31, 2017 was 17,206 boe/d versus 18,407 boe/d for the same period in 2016. After adjusting for the dispositions, total production remained in line with the prior period. In response to commodity price levels and volatility and given the nature of the Company's asset base, Cona has been able to maintain a conservative capital program with minimal production impact.

Commodity Prices

	Three months ended December 31			Years ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Average Benchmark Prices & Rates						
WTI oil (US$/bbl)[1]	**55.40**	49.29	12	**50.95**	43.32	18
CAD/USD exchange rate	**1.2717**	1.3339	(5)	**1.2979**	1.3256	(2)
WTI oil (CAD$/bbl)	**70.47**	65.74	7	**66.11**	57.26	15
Edmonton par oil (CAD$/bbl)	**69.02**	61.58	12	**62.91**	52.99	19
WCS heavy oil (CAD$/bbl)[2]	**54.87**	46.63	18	**50.54**	38.90	30
Heavy oil differential[3]	**22%**	29%	(24)	**23%**	33%	(30)
AECO natural gas (CAD$/mcf)[4]	**1.69**	3.09	(45)	**2.16**	2.16	-
Cona Average Realized Prices						
Excluding physical hedging						
Heavy oil ($/bbl)[5]	**50.38**	43.48	16	**46.68**	35.74	31
Light oil ($/bbl)	**-**	55.03	(100)	**-**	46.16	(100)
Oil ($/bbl)	**50.38**	43.73	15	**46.68**	36.05	29
Natural gas ($/mcf)	**2.95**	2.97	(1)	**2.50**	2.01	24
Combined ($/boe)	**50.03**	43.23	16	**46.22**	35.54	30
Including physical hedging[6]						
Heavy oil – excluding physical hedging ($/bbl)	**50.38**	43.48	16	**46.68**	35.74	31
Impact of physical delivery contracts ($/bbl)	**-**	(0.32)	(100)	**-**	(0.47)	(100)
Heavy oil – including physical hedging ($/bbl)	**50.38**	43.16	17	**46.68**	35.27	32
Light oil ($/bbl)	**-**	55.03	(100)	**-**	46.16	(100)
Oil – including physical hedging ($/bbl)	**50.38**	43.42	16	**46.68**	35.59	31
Combined – excluding physical hedging ($/boe)	**50.03**	43.23	16	**46.22**	35.54	30
Impact of physical delivery contracts ($/boe)	**-**	(0.30)	(100)	**-**	(0.45)	(100)
Combined – including physical hedging ($/boe)	**50.03**	42.93	17	**46.22**	35.09	32

Notes:

(1) WTI refers to the calendar monthly average based on the NYMEX prompt month.

(2) WCS refers to the calendar monthly average posting price in Canadian dollars for the Western Canadian Select oil blend at Hardisty.

(3) WTI/WCS differential refers to the discount of the WCS benchmark price relative to WTI.

(4) AECO refers to the monthly average of AECO Daily (5A) index price.

(5) Realized oil prices are calculated based on oil sales net of blending expenses. See “Blending, Transportation and Other Expenses”.

(6) Cona’s risk management strategy includes both physical delivery contracts (fixed price forward sales) and financial derivative contracts. The impact of financial derivative contracts is disclosed separately in the consolidated statement of operations. There was a physical contract in effect for 2016. The impact of physical delivery contracts (when applicable) is included in oil and natural gas sales in the consolidated statement of operations on their settlement dates.

Oil Prices

Cona’s oil has average gravities of 12 to 17 degrees API. The Company markets oil based on prices linked to the WCS oil stream, adjusted for the quality of Cona’s oil, specific to each delivery point. The WCS benchmark price is influenced by WTI (a North American benchmark price for light sweet crude oil), the WTI/WCS differential and the US/Canadian foreign exchange rate. The WTI/WCS differential is impacted by the availability of midstream infrastructure, transportation costs, quality adjustments and the supply of and demand for particular crude oil streams.

During the fourth quarter of 2017, average WTI prices were US$55.40/bbl compared to US$49.29/bbl for the same period in 2016. During 2017, average WTI prices were US$50.95/bbl compared to US$43.32/bbl for the same period in 2016.

The WTI/WCS differential averaged 22% of WTI in the fourth quarter of 2017 compared to 29% for the same period in 2016. For 2017, the WTI/WCS differential averaged 23% compared to 33% for the same period in 2016.

During the fourth quarter of 2017, the Canadian dollar averaged $1.2717 per US dollar compared to $1.3339 for the same period in 2016. During 2017, the Canadian dollar averaged $1.2979 per US dollar, strengthening from $1.3256 for the same period in 2016. A weakening in the Canadian dollar positively impacts oil revenue, whereas a strengthening in the Canadian dollar will decrease oil revenues as sales prices of North American crude oil are denominated in US dollars.

Cona’s average realized oil price, prior to the effect of physical delivery contracts (when applicable), increased to $50.38/bbl in the fourth quarter of 2017 from $43.73/bbl for the same period in 2016. The 15% increase in realized oil price was due to higher WTI oil prices and narrower WTI/WCS differentials partially offset by a strengthening in the Canadian dollar. The discount of Cona’s average realized oil price to WCS largely reflects the cost of blending Cona’s oil with diluents to meet pipeline specifications.

Cona’s average realized oil price increased to $46.68/bbl for the year ended December 31, 2017 from $36.05/bbl for the same period in 2016. The 29% increase was mainly due to higher WTI oil prices and narrower WTI/WCS differentials.

Natural Gas Prices

Cona's natural gas is sold under a marketing arrangement tied to the AECO index. Natural gas prices are impacted by supply and demand dynamics that include natural gas storage levels and weather conditions.

For the fourth quarter of 2017, average realized natural gas prices were $2.95/mcf compared to $2.97/mcf for the same period in 2016. For the year ended December 31, 2017, average realized natural gas prices were $2.50/mcf compared to $2.01/mcf for the same period in 2016. The movements in realized prices corresponded with the changes in AECO benchmark prices plus an adjustment to the TransGas Energy Pool price.

Risk Management

Cona's risk management strategy includes physical delivery, financial derivative and foreign exchange contracts that is designed to protect realized prices on crude oil volumes. The Company's revolving credit facility allows it to hedge commodity prices for up to four years, with certain limitations. In the first two forward years, hedged volumes are limited to 70% of working interest production. In the third and fourth years, hedged volumes are limited to 50% of working interest production. On the measurement date, the percentages of hedged working interest production are calculated based on production volumes from the immediately preceding fiscal quarter.

Cona enters into WTI contracts and WTI/WCS differential contracts to protect against commodity price movements. Cona may also enter into foreign exchange contracts to manage Canadian and US dollar foreign exchange rate volatility.

Total hedged volumes are as follows:

	2018		2019	
(C$)(1,2)	Hedged volumes (bbl/d)	Average WTI Price (C$/bbl)	Hedged volumes (bbl/d)	Average WTI Price (C$/bbl)
As at December 31, 2017	8,000	63.89	-	-
Subsequent to December 31, 2017				
Revised contract	(2,000)	(59.84)	-	-
Revised contract	2,000	65.00	2,000	65.00
Total	8,000	64.91	2,000	65.00

Notes:

(1) Contracts denominated in US dollars have been converted to Canadian dollars at the CAD/USD daily exchange rate for December 29, 2017.

(2) The prices and volumes in this table represent averages for several contracts over the 2018 calendar year. The average price of a group of contracts is for indicative purposes only and does not have the same settlement profile as the individual contracts. Details of the risk management contracts in place are disclosed in Note 20 of the Company's consolidated financial statements for the years ended December 31, 2017 and 2016.

Physical delivery contracts (when applicable) are included in oil and natural gas sales in the consolidated statement of operations and are not recorded on the consolidated statement of financial position. See "Commodity Prices – Cona Average Realized Prices" above.

The Company records commodity and foreign exchange contracts (when applicable) at fair value in the consolidated statement of financial position. The fair values are based on an approximation of the amounts that would have been paid to, or received from, counterparties to settle the contracts outstanding as at the end of the period with reference to forward prices for commodities, forward exchange rates and market values provided by independent sources. The actual amounts realized may differ from these estimates. Gains and losses on financial derivative contracts are shown on the consolidated statement of operations and comprise both realized and unrealized gains and losses. Realized gains and losses represent the portion of contracts that have settled during the period and unrealized gains or losses represent the change in the fair value of outstanding contracts from one period to the next.

The following is a summary of the gain (loss) on the financial derivative contracts:

	Three months ended December 31			Years ended December 31		
($000s, unless otherwise noted)	**2017**	2016	% Change	**2017**	2016	% Change
Realized gain (loss)	**(3,699)**	15,055	(125)	**(3,908)**	93,557	(104)
Unrealized gain (loss)	**(23,722)**	(48,232)	(51)	**22,106**	(163,630)	114
Total	**(27,421)**	(33,177)	(17)	**18,198**	(70,073)	126
Realized gain (loss) per boe ($)[1]	**(2.34)**	8.84	(126)	**(0.62)**	13.97	(104)

Note:

(1) Realized gain (loss) per boe is calculated using sales volumes. See “Production”.

During the fourth quarter of 2017, Cona realized $3.7 million in losses on financial derivative contracts compared to $15.1 million in gains for the same period in 2016. During the three months ended December 31, 2017, losses on WCS differential contracts were due to narrower than hedged WTI/WCS differentials and losses on WTI contracts were due to higher than hedged oil prices for the period. During the three months ended December 31, 2016, gains realized on Canadian dollar WTI contracts were mainly due to lower than hedged oil prices.

During the year ended December 31, 2017, Cona realized $3.9 million in losses on financial derivative contracts compared to $93.6 million in gains for the same period in 2016. Losses on financial derivative contracts were due to narrower than hedged WTI/WCS differentials, partially offset by gains realized on WTI contracts due to lower than hedged oil prices. In 2016, gains realized on Canadian dollar WTI contracts were due to lower than hedged oil prices.

For the fourth quarter of 2017, an unrealized mark-to-market loss of $23.7 million was recorded on financial derivative contracts compared to a loss of $48.2 million for the same period in 2016. For the three months ended December 31, 2017, the unrealized loss was mainly due to stronger forward Canadian dollar WTI prices at December 31, 2017 compared to September 30, 2017. For the three months ended December 31, 2016, the unrealized loss was due to stronger forward Canadian dollar WTI prices at December 31, 2016 compared to September 30, 2016 and contracts that settled upon maturity that were previously recorded as unrealized gains.

For the year ended December 31, 2017, an unrealized mark-to-market gain of $22.1 million was recorded on financial derivative contracts compared to a loss of $163.6 million for the same period in 2016. For the year ended December 31, 2017, the unrealized gains were due to the maturity of WTI contracts that were previously recorded as unrealized losses, partially offset by the maturity of WCS differential contracts that were previously recorded as unrealized gains. The unrealized loss in 2016 was due to 2016 financial derivative contracts that were realized during the period and losses on contracts entered into during the period due to higher than hedged WTI prices. The unrealized losses were partially offset by unrealized gains due to wider than hedged WTI/WCS differential contracts.

The following table summarizes the sensitivity of the fair value of the Company's financial derivative positions as at December 31, 2017 to fluctuations in oil prices, with all other variables held constant. For the purposes of assessing the potential impact of these oil price changes, the Company has used a volatility measure of 10 percent. Fluctuations in oil prices potentially could have resulted in unrealized gains (losses) impacting income after tax as follows:

($000s)	December 31, 2017		December 31, 2016	
	Decrease 10%	Increase 10%	Decrease 10%	Increase 10%
Value of derivative positions[1]	15,213	(15,731)	27,400	(24,778)

Note:

(1) Value of derivative positions at December 31, 2017 was a liability of $30.8 million (December 31, 2016 – liability of $52.9 million).

The following table shows the impact of Cona's hedging program on average realized oil prices and operating netbacks:

	Three months ended December 31			Years ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Average Realized Oil Prices ($/bbl)						
Excluding physical hedging	**50.38**	43.73	15	**46.68**	36.05	29
Impact of physical delivery contracts	**-**	(0.31)	(100)	**-**	(0.46)	(100)
Impact of financial derivative contracts	**(2.36)**	9.02	(126)	**(0.63)**	14.28	(104)
Including hedging	**48.02**	52.44	(8)	**46.05**	49.87	(8)
Operating Netbacks ($/boe)[1]						
Excluding physical hedging	**25.14**	21.26	18	**21.85**	14.12	55
Impact of physical delivery contracts	**-**	(0.30)	(100)	**-**	(0.45)	(100)
Impact of financial derivative contracts	**(2.34)**	8.84	(126)	**(0.62)**	13.97	(104)
Including hedging	**22.80**	29.80	(23)	**21.23**	27.64	(23)

Note:

(1) "Operating netbacks" is a non-IFRS financial measure. See the discussion under the heading "Non-IFRS Financial Measures".

For the fourth quarter of 2017, financial derivative contracts decreased Cona's average realized oil price and operating netback by $2.36/bbl and $2.34/boe, respectively. For the fourth quarter of 2016, physical delivery and financial derivative contracts added $8.71/bbl to Cona's average realized oil price and $8.54/boe to the Company's operating netback.

For the year ended December 31, 2017, financial derivative contracts reduced Cona's average realized oil price and operating netback by $0.63/bbl and $0.62/boe, respectively. For the year ended December 31, 2016, physical delivery and financial derivative contracts added $13.82/bbl to Cona's average realized oil price and $13.52/boe to the Company's operating netback.

Financial Instruments and Other Instruments

The Company utilizes financial derivative contracts and physical delivery contracts to reduce its exposure to fluctuations in commodity prices. These instruments are discussed in “Commodity Prices - Risk Management” above. The Company utilizes CAD/USD foreign exchange swaps and CAD/USD call options to reduce exposure to fluctuations in the CAD/USD foreign exchange rate. At December 31, 2017, no additional risk management instruments were outstanding in order to mitigate other risks to which the Company is exposed.

Oil and Natural Gas Sales

	Three months ended December 31			Years ended December 31		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Heavy oil sales[1]	**98,806**	91,467	8	**366,696**	297,929	23
Light oil sales	**-**	2,018	(100)	**-**	9,092	(100)
Natural gas sales	**298**	587	(49)	**1,388**	1,733	(20)
Total	**99,104**	94,072	5	**368,084**	308,754	19

Note:

(1) Oil produced by Cona requires blending with diluents to reduce its viscosity to meet pipeline specifications. Cona also purchases, blends and sells third party crude oil. Oil sales includes the sale of Cona’s proprietary volumes, the sale of third party crude oil and the sale of diluent volumes used for blending. See “Blending, Transportation and Other Expenses”.

Oil accounted for over 99% of total sales revenue for both the fourth quarter of 2017 and for the year ended December 31, 2017, which is consistent with the respective comparative periods in 2016.

Oil and natural gas sales increased 5% to $99.1 million in the fourth quarter of 2017 from $94.1 million for the same period in 2016. The increase was primarily due to higher benchmark oil prices and narrower WTI/WCS differentials, partially offset by lower sales volumes.

Oil and natural gas sales increased 19% to $368.1 million in the year ended December 31, 2017 from $308.8 million for the same period in 2016. The increase was primarily due to the reasons discussed above.

Royalties

	Three months ended December 31			Years ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Royalty expenses ($000s)	**8,189**	7,801	5	**30,560**	24,716	24
Average royalty rate (%)[1]	**10.8**	11.1	(3)	**11.0**	10.9	1
$ per boe	**5.18**	4.58	13	**4.86**	3.69	32

Note:

(1) Average royalty rate is calculated on oil and natural gas sales, exclusive of hedging, less blending and transportation expenses.

Royalty expenses include Crown royalties, freehold royalties, the Saskatchewan resource surcharge, freehold production taxes and overriding royalties. Crown royalties and freehold royalties include amounts paid to the owners of mineral rights. The Saskatchewan resource surcharge and the freehold production tax are levied by the Saskatchewan provincial government. Overriding royalties are typically paid to third parties as a result of a contract created by a farm-in arrangement or prospect development.

Royalties are dependent on commodity prices, well productivity and well vintage. Crown royalties are calculated using a sliding scale where lower rates are applied during periods of low commodity prices and to wells that are less productive.

Enhanced oil recovery ("EOR") wells (e.g. polymer flood and SAGD) qualify for the Government of Saskatchewan's reduced Crown royalty rate of 1% until project payout. Horizontal wells qualify for the Government of Saskatchewan's reduced Crown royalty rate of 2.5% for up to 37,700 barrels of oil produced from the well. Other oil royalty rates, including Crown and non-Crown royalties (e.g. Saskatchewan resource surcharge and/or overriding royalties), are applied in addition to those previously mentioned.

Royalty expenses were $8.2 million in the fourth quarter of 2017 compared to $7.8 million for the same period in 2016. Cona's average royalty rate for the fourth quarter of 2017 was 10.8% versus 11.1% for the same period in 2016. The decrease in the average royalty rate was mainly due to the sale of properties with higher average royalty rates, partially offset by higher oil prices.

Royalty expenses were $30.6 million for the year ended December 31, 2017 compared to $24.7 million for the same period in 2016. Cona's average royalty rate for 2017 was 11.0%, which was close to 10.9% for the same period in 2016.

During the year ended December 31, 2017, royalties paid to the Government of Saskatchewan represented approximately 78% of the total royalties paid (2016 – 77%).

Production and Operating Expenses

	Three months ended December 31			Years ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Production and operating expenses ($000s)	**27,768**	26,264	6	**109,098**	106,542	2
$ per boe	**17.55**	15.42	14	**17.37**	15.91	9

The most significant components of Cona's production and operating expenses are utilities (primarily power), surface maintenance, downhole maintenance, labour, lease rentals and property taxes.

Production and operating expenses for the fourth quarter of 2017 were $27.8 million ($17.55/boe) compared to $26.3 million ($15.42/boe) for the same period in 2016. Total costs per unit were higher in the fourth quarter of 2017 primarily due to lower sales volumes compared to the fourth quarter of 2016. In addition, surface maintenance costs increased due to a higher number of repairs and equipment replacements in the quarter, while downhole maintenance costs were higher due to increased well servicing activity during the period.

Production and operating expenses for the year ended December 31, 2017 were $109.1 million ($17.37/boe) compared to $106.5 million ($15.91/boe) for the same period in 2016. Total costs per unit were higher in the year ended December 31, 2017 primarily due to lower sales volumes compared to the same period in 2016, higher surface maintenance costs, utilities costs, downhole maintenance costs and turnaround costs. The increase on a per boe basis was partially offset by lower chemical costs. Surface maintenance costs and downhole maintenance costs increased over the course of the year due to the reasons discussed above. Utilities costs were higher due to an increase in power usage and electricity rates. Turnaround costs were higher due to increased turnaround activity compared to 2016. Chemical costs were lower mainly due to a reduction in chemical use.

Blending, Transportation and Other Expenses

	Three months ended December 31			Years ended December 31		
($000s, unless otherwise noted)	**2017**	2016	% Change	**2017**	2016	% Change
Diluent and other expenses[1,2]	**19,202**	17,895	7	**71,789**	61,848	16
Transportation expenses	**3,420**	3,358	2	**13,454**	12,220	10
Purchases of third party crude oil[2,3]	**765**	3,080	(75)	**5,964**	11,956	(50)
Total	**23,387**	24,333	(4)	**91,207**	86,024	6
Transportation expenses ($ per boe)	**2.16**	1.97	10	**2.14**	1.82	18

Notes:

(1) Oil produced by Cona requires blending with diluent to reduce its viscosity to meet pipeline specifications. The cost of diluent is only partially recovered in the selling price of blended oil, which is the primary difference between WCS prices and our realized oil price.

(2) Oil sales includes the sale of Cona's proprietary volumes, the sale of third party crude oil and the sale of diluent volumes used for blending. The cost of diluent represents the majority of diluent and other expenses. Purchases of third party crude oil are deducted in the calculation of the realized oil sales price. See "Commodity Prices".

(3) Cona purchases, blends and sells third party crude oil. The cost of third party oil is recorded in blending expenses. The revenue from the sale of third party oil is recorded in oil sales.

Diluent and other expenses for the fourth quarter of 2017 were $19.2 million compared to $17.9 million for the same period in 2016 due primarily to an increase in the cost of diluent. The cost incurred to purchase third party crude oil decreased as Cona purchased less third party volumes compared to the same period in 2016. During the fourth quarter of 2017, blend sales represented approximately 92% of the Company's oil sales volumes (2016 – 88%).

Diluent and other expenses for the year ended December 31, 2017 were $71.8 million compared to $61.8 million for the same period in 2016 due primarily to an increase in the cost of diluent. The cost incurred to purchase third party crude oil decreased due to the reason discussed above. For the year ended December 31, 2017, blend sales represented approximately 92% of the Company's oil sales volumes (2016 – 86%).

The Company incurs transportation expenses to transport oil to points of sale. These expenses include pipeline tariffs, terminal fees and clean oil trucking. Cona's natural gas production is flow-lined through Cona's natural gas gathering lines and sold at metering stations at the facilities.

Transportation expenses for the fourth quarter of 2017 of $3.4 million ($2.16/boe) were slightly higher than $3.4 million ($1.97/boe) for the same period in 2016. Higher pipeline tariffs in 2017 were largely offset by lower clean oil trucking costs resulting from property dispositions in the fourth quarter of 2016 and lower production volumes from certain properties where production is trucked to sales points.

Transportation expenses for the year ended December 31, 2017 of $13.5 million ($2.14/boe) were higher than $12.2 million ($1.82/boe) for the same period in 2016. Higher tariffs were partially offset by lower clean oil trucking costs. Tariffs were higher as a result of an increase in throughput volumes on pipelines with higher tariff rates along with prior period adjustments. Clean oil trucking costs decreased mainly due to the reasons noted above.

General and Administrative ("G&A") Expenses

	Three months ended December 31			Years ended December 31		
($000s, unless otherwise noted)	**2017**	2016	% Change	**2017**	2016	% Change
Total G&A costs	**5,413**	6,943	(22)	**21,976**	29,754	(26)
Change of control costs	**-**	-		**4,356**	-	100
Operating recoveries	**(1,456)**	(1,578)	(8)	**(6,081)**	(6,438)	(6)
Capitalized to oil and natural gas properties	**(569)**	(665)	(14)	**(2,505)**	(1,734)	44
G&A expensed	**3,388**	4,700	(28)	**17,746**	21,582	(18)
$ per boe	**2.14**	2.76	(22)	**2.82**	3.22	(12)

G&A costs relate primarily to personnel, occupancy costs, professional services and information technology systems. Consistent with industry practice, Cona burdens the Company's operated wells and facilities with an overhead recovery and capitalizes development related personnel costs to oil and natural gas properties.

G&A expensed during the fourth quarter of 2017 of $3.4 million ($2.14/boe) was 28% lower than $4.7 million ($2.76/boe) for the same period in 2016. The decrease was mainly due to lower compensation levels, a decrease in the number of personnel and lower professional fees.

G&A expensed during the year ended December 31, 2017 of $17.7 million ($2.82/boe) was 18% lower than $21.6 million ($3.22/boe) for 2016. After adjusting for $4.4 million ($0.69/boe) of costs related to the change of control, total G&A costs decreased by 38% compared to 2016. The decrease was due to lower compensation levels, a decrease in the number of personnel and lower occupancy costs as a result of an onerous contract provision. Higher capital recoveries were due to increased capital spending. G&A expensed on a dollar per boe basis, after adjusting for the change of control costs, decreased to $2.13/boe in the year ended December 31, 2017 from $3.22/boe for the year ended December 31, 2016.

Finance Costs

	Three months ended December 31			Years ended December 31		
($000s, unless otherwise noted)	**2017**	2016	% Change	**2017**	2016	% Change
Interest expense[(1)]	**5,422**	6,740	(20)	**26,501**	28,805	(8)
Amortization of debt issuance costs	**807**	234	245	**1,907**	936	104
Accretion of decommissioning provision	**1,125**	903	25	**4,251**	2,779	53
Accretion of onerous contract provision	**13**	-	100	**48**	-	100
Finance costs	**7,367**	7,877	(6)	**32,707**	32,520	1
Cash finance costs ($ per boe)[(1)]	**3.43**	3.96	(13)	**3.89**	4.30	(10)

Note:

(1) Cash finance costs per boe relate to finance costs that impact funds from operations. During the third quarter of 2017, Cona purchased a US$250.0 million CAD/USD call option for $2.1 million. The call option premium is included in financing activities on the statement of cash flows and is included in interest expense in the table above.

Finance costs are comprised of interest expense on borrowings, amortization of debt issuance costs, accretion of the decommissioning provision and accretion of an onerous contract provision. Interest expense, the cash component of finance costs, includes interest and fees paid on Cona's revolving credit facility, the Term Loan and the US denominated Senior Notes (see Note 9 to the Company's consolidated financial statements for the years ended December 31, 2017 and 2016). Cona's interest rates on the revolving credit facility are based on a margin grid and the interest rates vary depending on the ratio of the Company's senior debt to EBITDA (see "Liquidity and Capital Resources – Financial Covenants"). The amortization of debt issuance costs relates to the recognition of deferred costs regarding the issuance of the Term Loan and the Senior Notes. Accretion expense relates to the increase in the carrying amount of the decommissioning provision and the onerous contract provision due to the passage of time.

Finance costs for the fourth quarter of 2017 were $7.4 million compared to $7.9 million for the same period in 2016. The decrease was due to a 20% decrease in interest expense resulting from a change in the composition of the Company's debt. During the fourth quarter of 2017, debt was comprised of borrowings on the credit facility and Term Loan, the blended interest paid was lower than the interest paid on the Senior Notes that were outstanding in the fourth quarter of 2016.

Finance costs for the year ended December 31, 2017 were $32.7 million compared to $32.5 million for the same period in 2016. Increased finance costs due to higher accretion expense and amortization of debt issuance costs were largely offset by lower cash interest expense. Interest expense decreased by 8% to $26.5 million primarily due to a lower blended interest rate on debt balances in 2017 and lower interest on Senior Notes while they were outstanding due to the strengthening of the Canadian dollar. This was partially offset by the cost of the call option purchased in the third quarter of 2017 related to the redemption of Senior Notes.

Foreign Exchange (Gain) Loss

	Three months ended December 31			Years ended December 31		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Realized (gain) loss	**(509)**	(881)	(42)	**45,581**	(151)	(30,286)
Unrealized (gain) loss	**(45)**	8,563	(101)	**(65,787)**	(11,399)	477
Foreign exchange (gain) loss	**(554)**	7,682	(107)	**(20,206)**	(11,550)	75

Foreign exchange gains or losses arise from a different foreign currency exchange rate at the transaction date versus the settlement date and from the translation to Canadian dollars of assets and liabilities denominated in a foreign currency. Cona's foreign exchange gains or losses arise primarily from US dollar denominated oil sales, the US dollar denominated Senior Notes (while outstanding) and realized gains and losses on financial derivative contracts denominated in US dollars. Gains or losses are also recorded on US dollar cash balances as a result of changes in exchange rates during the respective period.

During the fourth quarter of 2017, Cona recorded realized foreign exchange gains of $0.5 million compared to gains of $0.9 million for the same period in 2016. The realized gains were primarily due to a weakening of the Canadian dollar between the transaction and settlement dates for US dollar denominated sales transactions.

During the year ended December 31, 2017, Cona recorded realized foreign exchange losses of $45.6 million compared to gains of $0.2 million in 2016. The realized losses in 2017 were primarily due to the purchase of the Senior Notes. The realized gain in 2016 was due to a weakening of the Canadian dollar between the transaction and settlement dates for US dollar denominated sales transactions.

During the fourth quarter of 2017, the Company recorded unrealized foreign exchange gains of $45,000 compared to unrealized losses of $8.6 million for the same period in 2016. The unrealized losses in the fourth quarter of 2016 were due to the translation of the outstanding principal amount of the Senior Notes as a result of a weaker Canadian dollar on December 31, 2016 relative to September 30, 2016. The Company purchased all of the outstanding Senior Notes in the third quarter of 2017.

During the year ended December 31, 2017, the Company recorded unrealized foreign exchange gains of $65.8 million compared to $11.4 million in 2016. The purchase of the Senior Notes crystalized unrealized losses recorded in prior periods. The unrealized losses from prior periods were reclassified to realized, which resulted in unrealized gains in the current period. In addition, a portion of the unrealized gains resulted from a stronger Canadian dollar when the Senior Notes were purchased relative to December 31, 2017. For the year ended December 31, 2016, the unrealized gains were due to the translation of the outstanding principal amount of the Senior Notes as a result of a stronger Canadian dollar on December 31, 2016 relative to December 31, 2015.

Netbacks

	Three months ended December 31			Years ended December 31		
($/boe)	**2017**	2016	% Change	**2017**	2016	% Change
Sales volumes (boe/d)[1]	**17,193**	18,508	(7)	**17,211**	18,295	(6)
Average realized price[2]	**50.03**	42.93	17	**46.22**	35.09	32
Royalties	**(5.18)**	(4.58)	13	**(4.86)**	(3.69)	32
Production and operating expenses	**(17.55)**	(15.42)	14	**(17.37)**	(15.91)	9
Transportation expenses	**(2.16)**	(1.97)	10	**(2.14)**	(1.82)	18
Operating netback[3]	**25.14**	20.96	20	**21.85**	13.67	60
Realized gains (losses) on financial derivative contracts	**(2.34)**	8.84	(126)	**(0.62)**	13.97	(104)
G&A expenses	**(2.14)**	(2.76)	(22)	**(2.13)**	(3.22)	(34)
Change of control costs[4]	**-**	-	-	**(0.69)**	-	(100)
Cash finance costs	**(3.43)**	(3.96)	(13)	**(3.89)**	(4.30)	(10)
Other[5]	**0.40**	0.52	(23)	**(0.20)**	0.05	(500)
Funds from operations[3]	**17.63**	23.60	(25)	**14.32**	20.17	(29)

Notes:

(1) Per unit amounts in operating netbacks and funds from operations per boe calculations are determined using sales volumes.

(2) Realized prices include the impact of physical delivery contracts when applicable. See “Commodity Prices”. There was a physical delivery contract in effect during 2016.

(3) “Operating netbacks” and “funds from operations” are non-IFRS financial measures. See discussion under the heading “Advisories – Non-IFRS Financial Measures”.

(4) Includes termination payments of $4.0 million and other costs of $0.4 million related to the change of control that occurred in May 2017.

(5) Other includes realized foreign exchange gains (losses) and other income.

The Company uses operating netback, funds from operations and funds from operations as indicators of operating performance and profitability on a per unit basis.

Share-based Compensation

	Three months ended December 31			Years ended December 31		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Total share-based compensation	**833**	1,776	(53)	**14,753**	11,066	33
Capitalized to oil and natural gas properties	**(68)**	(158)	(57)	**(1,432)**	(655)	119
Revaluation of share-based compensation liability	**(46)**	47	(198)	**(1,296)**	(776)	67
Share-based compensation expense	**719**	1,665	(57)	**12,025**	9,635	25

Share-based compensation expense for the fourth quarter of 2017 was $0.7 million compared to $1.7 million for the same period in 2016. Total share-based compensation decreased due to a lower number of Awards outstanding and the Awards that became payable during the fourth quarter of 2017 had a lower fair value on their grant date.

Share-based compensation expense for the year ended December 31, 2017 was $12.0 million compared to $9.6 million in 2016. Total share-based compensation increased due to the Awards that became payable as a result of the change of control.

The change of control in May 2017 resulted in 4.4 million Awards becoming payable for total consideration of $14.9 million. The Awards were settled with a combination of $12.2 million in cash and 781,327 common shares valued at $2.7 million based on a 5 day volume weighted price at the time of the Award settlement. The common shares used for the settlement were purchased in the open market.

For a description of Cona's Incentive Plan and related accounting policy, refer to Notes 3, 4 and 17 of the Company's consolidated financial statements for the years ended December 31, 2017 and 2016.

At December 31, 2017, the Company had 1,463,145 time-based awards and 529,100 performance awards outstanding. Subsequent to December 31, 2017, the Company granted 28,823 time-based awards.

Depletion, Depreciation, Amortization ("DD&A") and Impairment

	Three months ended December 31			Years ended December 31		
($000s, unless otherwise noted)	**2017**	2016	% Change	**2017**	2016	% Change
Depletion of oil and natural gas properties and equipment	**38,229**	28,991	32	**119,708**	126,068	(5)
Depreciation of other fixed assets	**167**	168	(1)	**616**	655	(6)
Amortization of other intangible assets	**282**	282	-	**1,128**	1,127	-
DD&A	**38,678**	29,441	31	**121,452**	127,850	(5)
Impairment	**75,616**	-	100	**75,616**	-	100
DD&A and impairment	**114,294**	29,441	288	**197,068**	127,850	51
$ per boe, before impairment	**24.45**	17.29	41	**19.33**	19.09	1
$ per boe	**72.26**	17.29	318	**31.37**	19.09	64

DD&A relates to the depletion of the Company's oil and natural gas properties and equipment, the depreciation of other fixed assets and the amortization of other intangible assets. Depletion is calculated on a field-by-field basis and is determined using the unit-of-production method which references the ratio of production in the period to proved plus probable reserves, taking into account the estimated future development costs required to bring those reserves into production. Costs are segregated and depleted on an area-by-area basis relative to their respective underlying reserves base and, as such, the Company's depletion rate will vary depending on the capital additions, changes in future development costs within the various areas as well as changes to the reserves base.

During the fourth quarter of 2017, Cona initiated a process to sell minor properties with a fair value of approximately $53.9 million. At December 31, 2017, these properties were classified as held for sale as management concluded it was highly probable within one year that the carrying value would be received through a sales transaction rather than through continued use. Assets classified as held for sale were measured at the lower of the carrying amount and fair value less costs of disposal, resulting in an impairment loss of $60.6 million. The fair value less costs of disposal of the assets held for sale was determined using third party information including potential estimated future cash flows and bids received from potential purchasers.

During the fourth quarter of 2017, Cona recorded DD&A of $38.7 million ($24.45/boe) compared to $29.4 million ($17.29/boe) for the same period in 2016. The increase in DD&A in the fourth quarter of 2017 was due to changes in reserves at the field level.

During the year ended December 31, 2017, Cona recorded DD&A of $121.5 million ($19.33/boe) compared to $127.9 million ($19.09/boe) for the same period in 2016. The decrease in DD&A for 2017 was mainly due to the dispositions of the Coleville and Smiley properties in the fourth quarter of 2016, partially offset by the change in reserves at the field level. DD&A costs on a dollar per boe basis increased 1% to $19.33/boe for the year ended December 31, 2017 from $19.09/boe in 2016 as lower sales volumes offset the decrease on an absolute dollar basis.

At December 31, 2017, the Company concluded that as a result of recent property disposition activity with anticipated proceeds lower than carrying values, the carrying value of the Lloydminster CGU exceeded its recoverable amount of $175.0 million. As a result, an impairment loss of $15.0 million was recorded to property, plant and equipment and as a component of DD&A and impairment expense.

Taxes

	Three months ended December 31			Years ended December 31		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Deferred income tax recovery	**(5,520)**	(40,835)	(86)	**(5,338)**	(74,745)	(93)

Deferred income tax recovery is a function of taxable loss which is calculated differently than loss before taxation for accounting purposes. Differences may arise due to the non-taxable portion of capital gains or capital losses, non-deductible share-based compensation expenses and other differences. Additionally, the recognition or de-recognition of certain deferred income tax assets can occur based on the Company's expected ability to realize their benefit in the future. The difference between the statutory income tax rate and deferred income tax recovery as a percentage of loss before taxation in both the current year and prior year periods was due to these types of items.

The statutory income tax rate applicable to Cona as of December 31, 2017 was 26.8% (2016 – 27.0%). Deferred income tax recovery as a percentage of loss before taxation for the year ended December 31, 2017 was 5.8% (2016 – 27.6% of loss before taxation). For the year ended December 31, 2017, the difference between the deferred income tax recovery as a percentage of income before taxation and the statutory income tax rate was primarily due to an unrecognized deferred tax asset in respect of non-capital losses and foreign exchange gains on the Senior Notes. For the year ended December 31, 2016, the difference between deferred income tax recovery as a percentage of income before taxation and the statutory income tax rate was primarily due to foreign exchange gains on the Senior Notes partially offset by non-deductible share-based compensation.

The Company has estimated future income tax deductions available, as set out below:

($000s)	**December 31, 2017**	December 31, 2016	Rate (%)
Canadian exploration expenditures	**1,617**	40,997	100
Canadian development expenditures	**109,634**	175,525	30
Canadian oil and gas property expenditures	**201,800**	297,354	10
Undepreciated capital costs	**271,477**	260,458	4 – 100
Non-capital losses	**389,538**	198,549	100
Finance costs	**22,638**	21,916	20 (straight line)
Other	**25**	1,251	7 – 100
Total	**996,729**	996,050	

Cash Flow From Operating Activities, Funds from Operations and Net Income

($000s, except per share figures and unless otherwise noted)	Three months ended December 31			Years ended December 31		
	2017	2016	% Change	**2017**	2016	% Change
Cash flow from operating activities – IFRS[1]	**27,550**	50,917	(46)	**68,602**	117,327	(42)
Changes in non-cash operating working capital	**(283)**	(11,011)	(97)	**4,566**	13,771	(67)
Decommissioning costs incurred	**388**	167	132	**1,115**	461	142
Cash settlement of Incentive Plan Awards	**-**	33	(100)	**12,292**	1,419	766
Share purchases for Incentive Plan	**-**	73	(100)	**2,396**	2,002	20
Onerous provision costs incurred	**227**	-	100	**898**	-	100
Funds from operations[2]	**27,882**	40,179	(31)	**89,869**	134,980	(33)
Per share – basic	**0.28**	0.33	(15)	**0.87**	1.14	(24)
Per share – diluted	**0.27**	0.32	(16)	**0.86**	1.11	(23)
Net loss	**(108,295)**	(120,531)	**(10)**	**(86,996)**	(196,213)	**(56)**
Per share – basic	**(1.07)**	(0.99)	**8**	**(0.85)**	(1.66)	**(49)**
Per share – diluted	**(1.07)**	(0.99)	**8**	**(0.85)**	(1.66)	**(49)**

Note:

(1) Cash flow from operating activities for the year ended December 31, 2017 includes termination payments of $4.0 million and other costs of $0.4 million related to the change of control that occurred in May 2017.

(2) "Funds from operations" is a non-IFRS financial measure. See discussion under the heading "Advisories – Non-IFRS Financial Measures".

Cash flow from operating activities for the fourth quarter of 2017 was $27.6 million compared to $50.9 million for the same period in 2016 and funds from operations were $27.9 million in the fourth quarter of 2017 compared to $40.2 million in 2016. The decrease in funds from operations was primarily due to realized losses on financial derivative contracts in the fourth quarter of 2017 compared to gains for the same period in 2016. Also contributing to the variance were higher production and operating expenses, partially offset by higher oil and natural gas sales and lower general and administrative costs for the three months ended December 31, 2017.

Cash flow from operating activities for the year ended December 31, 2017 was $68.6 million compared to $117.3 million for the same period in 2016 and funds from operations for the year was $89.9 million compared to $135.0 million for the same period in 2016. The decrease in funds from operations in 2017 was primarily due to realized losses on financial derivative contracts compared to gains for the same period in 2016, higher royalty costs and higher blending costs, partially offset by higher oil and natural gas sales.

Net loss of $108.3 million for the fourth quarter of 2017 was mainly due to depletion, depreciation, amortization and impairment expense and unrealized losses on financial derivative contracts, partially offset by funds from operations. Net loss of $120.5 million for the fourth quarter of 2016 was mainly due to unrealized losses on financial derivative contracts and depletion, depreciation and amortization expense, partially offset by funds from operations.

Net loss of $87.0 million for the year ended December 31, 2017 was mainly due depletion, depreciation, amortization and impairment expense, partially offset by funds from operations, unrealized gains on foreign exchange and unrealized gains on financial derivative contracts. Net loss of $196.2 million for the same period in 2016 was mainly due to unrealized losses on financial derivative contracts and depreciation, depletion and amortization expense, partially offset by funds from operations and unrealized gains on foreign exchange.

Capital Expenditures

	Years ended December 31,	
($000s)	**2017**	2016
Land acquisition & retention	**70**	668
Geological & geophysical	**73**	61
Drilling, completions and equipment	**29,569**	22,685
Recompletions & workovers	**7,318**	5,974
Facilities and pipelines	**20,507**	21,767
Development and exploration	**57,537**	51,155
Dispositions	**(1,698)**	(72,954)
Total oil and natural gas expenditures	**55,839**	(21,799)
Corporate assets	**395**	290
Total capital expenditures	**56,234**	(21,509)
Relating to exploration and evaluation assets	**-**	-
Relating to property, plant and equipment	**56,234**	(21,509)
Total capital expenditures	**56,234**	(21,509)

Development and exploration expenditures totalled $57.5 million for the year ended December 31, 2017 compared to $51.2 million for the same period in 2016. Spending on drilling, completions and equipment of $29.6 million in 2017 was higher than $22.7 million in 2016. The difference was due to an increase in the number of wells drilled.

The table below summarizes Cona's drilling program for the years ended December 31, 2017 and 2016:

	2017		2016	
Field	**Gross**	**Net**	Gross	Net
Cactus Lake	**37**	**37.0**	29	29.0
Winter[(1)]	**32**	**29.0**	17	14.6
Coleville	**-**	**-**	14	9.8
Other	**1**	**1.0**	-	-
Total	**70**	**67.0**	60	53.4

Note:

(1) There were 2.0 net service wells drilled at Winter during 2017 (2016 – 1.0 net).

Decommissioning Provision

Cona's December 31, 2017 decommissioning provision of $190.2 million (2016 – $203.2 million) results from its ownership in oil and natural gas properties. In late 2017, the Company initiated a process to sell a number of minor properties which resulted in the reclassification of $61.4 million from decommissioning provision to liabilities held for sale on the consolidated statement of financial position. Undiscounted future cash flows of approximately $355.6 million (2016 – $334.6 million), which includes liabilities held for sale, are expected to be made over the next 50 years with the majority of costs to be incurred between 2022 and 2067. A weighted average risk free rate of 2.30% (2016 – 1.75%) and an inflation rate of 2.00% (2016 – 1.75%) per annum were used to calculate the present value of the decommissioning provision.

Total Payout Ratio

	Three months ended December 31			Years ended December 31,		
(%)	**2017**	2016	% Change	**2017**	2016	% Change
Total payout ratio[(1)]	**55**	73	(25)	**83**	80	4

Note:

(1) "Total payout ratio" is a non-IFRS financial measure. See discussion under the heading "Advisories – Non-IFRS Financial Measures".

Total payout ratio of 55% for the fourth quarter of 2017 compared to 73% for the fourth quarter of 2016. For the three months ended December 31, 2017, funds from operations were higher than capital expenditures. The suspension of the dividend following the payment in August 2017 along with lower capital spending during the period has reduced the total payout ratio.

Total payout ratio of 83% for the year ended December 31, 2017 compared to 80% for the same period in 2016. For the year ended December 31, 2017, funds from operations were higher than capital expenditures and dividends paid.

DIVIDENDS

	Three months ended December 31			Years ended December 31		
($000s, unless otherwise noted)	**2017**	2016	% Change	**2017**	2016	% Change
Accumulated dividends						
Beginning of period	**189,559**	162,739	16	**174,969**	120,572	45
Dividends declared	**-**	12,230	(100)	**14,590**	54,397	(73)
End of period	**189,559**	174,969	8	**189,559**	174,969	8
Accumulated dividends per share						
Beginning of period	**1.739**	1.499	16	**1.599**	1.139	40
Dividends declared	**-**	0.100	(100)	**0.140**	0.460	(70)
End of period	**1.739**	1.599	9	**1.739**	1.599	9

Cona's monthly dividend was suspended in August 2017, following the last dividend paid on August 15, 2017.

During 2016, the Company had a stock dividend program that enabled shareholders to receive dividends in the form of cash or common shares. The Company issued 7.7 million common shares to shareholders under the stock dividend program during the year ended December 31, 2016. The stock dividend program was discontinued immediately after the dividend payment on December 15, 2016.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure and Net Debt

The Company's capital structure is as follows:

($000s, unless otherwise indicated)	**December 31, 2017**	December 31, 2016
Bank loan	**188,464**	-
Term Loan – principal amount	**140,000**	-
Senior Notes – principal amount	**-**	370,921
Onerous contract provision(1)	**3,682**	4,545
Working capital (surplus) deficit(2)	**812**	(123,118)
Net debt(3)	**332,958**	252,348
Shareholders' equity	**593,539**	784,215
Total capitalization	**926,497**	1,036,563
Net debt as a percentage of total capitalization (%)	**35.9**	24.3
Net debt to funds from operations(4)	**3.7x**	1.9x

Notes:

(1) Onerous contract provision relates to an onerous office lease contract (see Note 11 to the Company's consolidated financial statements for the years ended December 31, 2017 and 2016).

(2) Working capital includes cash, accounts receivable, inventory, prepaid expenses and deposits, accounts payable and accrued liabilities and dividends payable.

(3) "Net debt" is a non-IFRS financial measure. See discussion under the heading "Advisories – Non-IFRS Financial Measures".

(4) Net debt to funds from operations is calculated as net debt divided by the trailing four quarters funds from operations. The credit facility financial covenant is a separate calculation – see "Financial Covenants" below.

Bank Loan

At December 31, 2017, the Company had a credit facility totaling $325.0 million (2016 - $285.0 million) with a syndicate of banks. At December 31, 2017, $188.5 million was drawn on the credit facility (2016 – $nil).

The revolving period is extendible annually by 364 days at the Company's request, subject to approval by each member of the syndicate. If the credit facility is not renewed at the end of the revolving period, currently July 13, 2018, outstanding borrowings under the credit facility are converted to a one year term loan. At the beginning of each revolving period, the credit facility is effectively a two year arrangement.

The credit facility is subject to semi-annual review and re-determination of the borrowing base by May 31 and October 31 of each year, or in the event of a material adverse effect. Any re-determination of the borrowing base is effective immediately and, if the borrowing base is reduced, the Company has 60 days to repay any shortfall.

Term Loan

At December 31, 2017, the Company had a Term Loan of $140.0 million. The outstanding amount was reduced to $140.0 million from $160.0 million as a result of a $20.0 million principal repayment in November 2017. Any repayment of borrowings results in a permanent reduction and cancellation of the commitment provided by lenders under the Term Loan.

In connection with the purchase of the Senior Notes, the Company entered into a $160.0 million Term Loan on July 28, 2017. The Term Loan matures on July 28, 2020, is repayable at par during the first year, 102.5% during the second year and 105.0% during the third year. Interest is payable monthly in arrears at the Canadian Dollar Offered Rate ("CDOR") plus 7.5% during the first year and CDOR plus 10.0% thereafter. A duration fee of 1% was paid based on the outstanding amount of the Term Loan on January 29, 2018. Mandatory prepayments are required with the net cash proceeds from certain asset sales and from certain debt issuances.

The Term Loan is carried at amortized cost, net of debt issuance costs. The debt issuance costs accrete up to the principal balance at maturity using an effective interest rate of 10.9% for the first year and 13.4% for the second and third years. At December 31, 2017, unamortized debt issuance costs were $7.6 million.

Equity

On February 3, 2017, the Company completed an issuer bid, whereby the Company paid $90.0 million to purchase for cancellation 22.5 million common shares at $4.00 per share. The issuer bid was funded with cash on hand.

The Company is authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares, issuable in series. As at December 31, 2017, Cona had 101.0 million common shares issued and outstanding, no preferred shares outstanding and Awards entitling the holders thereof to receive 2.0 million common shares (assuming a performance multiplier of 1x for performance awards).

As at March 6, 2018, Cona had 101,005,757 common shares issued and outstanding, 1,961,968 long-term incentive plan Awards outstanding and no preferred shares outstanding.

Liquidity

Cona remains focused on financial flexibility and long-term sustainability in a low oil price environment. Cona has implemented a number of measures to achieve this, including ensuring the Company has a comprehensive and ongoing review of capital, operating and administrative expenditures, continued commitment to our hedging program to protect our financial position and an asset disposition program. Cona regularly prepares and updates budgets and forecasts in order to monitor its liquidity and ability to meet its financial obligations and commitments, including the ability to comply with the financial covenants under the Company's credit facility and Term Loan (see "Financial Covenants" below).

At December 31, 2017, the Company had $136.2 million available under its revolving credit facility to cover any working capital deficiencies. All repayments on the revolving credit facility are due at the term maturity date, one year after the end of the revolving period. The revolving period is extendible annually with the approval of each bank party to the credit facility. As the bank loan and Term Loan do not mature within the next year, the liabilities are considered to be long-term.

Future liquidity depends primarily on funds flow from operations, existing credit facilities, the ability to dispose of assets and the ability to access debt and equity markets. The volatility in commodity prices (most notably the recent increase in heavy oil differentials) and foreign exchange rates may adversely affect the Company's operating results and financial position and it is possible that the Company could breach one or more of its financial covenants. A covenant violation is considered an event of default under each of the credit facility and the Term Loan and, if not remedied or waived by lenders, results in the right of lenders to demand repayment of all amounts owed. Cross default and/or cross acceleration provisions contained in the credit facility and Term Loan could result in all amounts owing under both arrangements becoming due immediately.

Cona is forecasting capital expenditures of $44.5 million for 2018. Cona anticipates that funds from operations and the revolving credit facility will be sufficient to finance current operations, planned capital expenditures and any working capital requirements for the next twelve months and foreseeable future.

Cona operates and controls substantially all of its development program. The incurrence and timing of most capital expenditures is discretionary in nature and there are no material long-term capital expenditure commitments.

The Company believes that its counterparties, in particular purchasers of crude oil and financial instrument counterparties, currently have the financial capacities in the normal course of business to honour their outstanding obligations to the Company. Cona periodically reviews the financial capacity of its counterparties and, in certain circumstances, the Company may seek enhanced credit protection from a counterparty or purchase accounts receivable insurance.

Financial Covenants

Cona's credit facility includes two financial covenants that are calculated quarterly and are described below. The calculation for each financial covenant is based on specific definitions and in some circumstances cannot be calculated by referring to Cona's consolidated financial statements. The Company's financial covenants are described as follows:

a) Senior Debt to EBITDA Ratio: Debt other than the Term Loan and permitted refinancing debt (as defined in the credit agreement) shall not exceed 3.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period.

b) Interest Coverage Ratio: Trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period, shall not be less than 2.5 times the trailing 12-month cash interest expense.

Cona's Term Loan has two financial covenants:

a) Minimum Asset Coverage Ratio: The ratio of the present value of proved developed producing reserves divided by the aggregate outstanding principal amount of the Term Loan plus funded credit facility debt shall be at least 1.0 times (at least 0.95 times as of December 31, 2017). The Minimum Asset Coverage Ratio is calculated semi-annually as of December 31 and June 30 of each year, no later than March 31 in respect of the December 31 ratio, and no later than October 31 in respect of the June 30 ratio. The present value of proved developed producing reserves is determined based on before tax cash flows using strip pricing as of the calculation date, discounted at 10% and is adjusted for hedges in place as of the calculation date.

b) Interest Coverage Ratio: Trailing 12-month net income before non-cash items, income taxes, interest expense and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period, shall not be less than 2.0 times the trailing 12-month cash interest expense. The Interest Coverage Ratio is tested quarterly commencing December 31, 2017.

The Company was in compliance with its financial covenants:

Covenant description	Covenant	Ratio(1)
Credit facility:		
Senior Debt to EBITDA Ratio(2)	Less than 3.0	**1.59**
Interest Coverage Ratio(2)	Greater than 2.5	**4.87**
Term Loan:		
Minimum Asset Coverage Ratio	Greater than 0.95	**1.24**
Interest Coverage Ratio(2)	Greater than 2.0	**4.87**

Notes:

(1) All ratios are calculated using information as at December 31, 2017 with the exception of the Minimum Asset Coverage Ratio which is calculated based on December 31, 2017 reserves and strip pricing as of February 28, 2018, determined in accordance with the Term Loan agreement.

(2) The calculation of trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period is provided in the table below. This calculation is used solely in calculating the financial covenants described above and is not used as an indicator of operating performance or profitability by the Company.

($000s)	Q1/17	Q2/17	Q3/17	Q4/17	Total
Net income (loss)	20,886	6,853	(6,440)	(108,295)	(86,996)
Finance costs	7,628	8,281	9,431	7,367	32,707
Unrealized (gain) loss on financial derivative contracts	(32,782)	(24,984)	11,938	23,722	(22,106)
Depletion, depreciation, amortization and impairment	27,385	27,706	27,683	114,294	197,068
Unrealized foreign exchange (gain) loss	(3,537)	(10,035)	(52,170)	(45)	(65,787)
Share based compensation	1,382	9,924	-	719	12,025
(Gain) loss on onerous contract	(82)	129	-	(60)	(13)
Loss on purchase and cancellation of Senior Notes	-	3,631	4,024	1,122	8,777
Income tax expense (recovery)	6,528	(313)	(6,033)	(5,520)	(5,338)
Incentive Plan cash payments	(391)	603	-	-	212
Onerous contract settlement costs incurred	(216)	(227)	(228)	(227)	(898)
Non-recurring expenses	773	5,819	42,625	106	49,323
Adjustment for material dispositions	(103)	16	5	1	(81)
	27,471	27,403	30,835	33,184	118,893

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has a number of contractual obligations and commitments that are incurred in the ordinary course of business. These obligations and commitments at December 31, 2017, and their expected timing of funding, are noted below.

($000s)	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Accounts payable and accrued liabilities	47,661	47,661	-	-	-
Share-based compensation	331	209	122	-	-
Financial derivative contracts	30,828	30,828	-	-	-
Bank loan[(1)]	188,464	-	188,464	-	-
Term Loan[(1)]	187,602	15,413	172,189	-	-
Fixed commitments[(2)]	26,356	7,132	8,718	7,413	3,093
Total	481,242	101,243	369,493	7,413	3,093

Notes:

(1) Amounts assume principal for the bank loan and Term Loan is repaid at maturity. Future interest payments and fees are only included on the Term Loan.

(2) Fixed commitments relate to non-cancellable payments for operating leases, transportation commitments and purchase commitments.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has certain fixed lease arrangements which were entered into in the normal course of operations. All leases are treated as operating leases, where the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability has been recorded for these leases on the statement of financial position at December 31, 2017 or December 31, 2016, except for the onerous contract provision. These fixed lease arrangements are disclosed in the notes to Cona's annual consolidated financial statements (see Note 23 of the Company's consolidated financial statements for the years ended December 31, 2017 and 2016).

Cona did not have any physical delivery contracts outstanding at December 31, 2017. The Company had one physical delivery contract in effect during 2016 and an asset or liability was not recorded on the statement of financial position.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")*, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed or submitted by the Company under Canadian securities legislation is recorded, processed, summarized and reported within the time periods specified under Canadian securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Cona evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Cona's DC&P were effective as at December 31, 2017.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Internal control over financial reporting ("ICFR"), as defined in NI 52-109, includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Cona;
2. are designed to 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 Cona are being made in accordance with authorizations of management and Directors of Cona; and
3. are designed to 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.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Cona. They have, as at the financial year ended December 31, 2017, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework used to design the Company's ICFR is the framework in

Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Cona conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2017. Based on this evaluation, the officers concluded that as of December 31, 2017, Cona maintained effective ICFR. It should be noted that while Cona's officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the control system will prevent all errors or fraud.

There were no changes during the period from October 1, 2017 to December 31, 2017 that have materially affected, or are reasonably likely to materially affect, Cona's ICFR.

CRITICAL ACCOUNTING ESTIMATES

A summary of Cona's significant accounting policies can be found in Note 4 to the Company's consolidated financial statements for the years ended December 31, 2017 and 2016. The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets and liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. Information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements are summarized below.

Oil and natural gas reserves

Proved and probable reserves have been estimated by internal and external experts and are based on a number of underlying assumptions, including oil and natural gas prices, future costs, oil and natural gas in place and reservoir performance, all of which are inherently uncertain. Established industry techniques are used to generate these estimates, however, the reserves that are ultimately recovered from any field cannot be known with certainty until the end of the field's life. Changes in reserves estimates could have a material impact on unit-of-production rates used for depletion, timing of decommissioning obligations and impairment of oil and natural gas properties.

Impairment of property, plant and equipment and intangible assets

The Company has significant investments in property, plant and equipment and intangible assets. Changes in circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired requiring the carrying value to be written down to its recoverable amount. Evaluating whether an asset is impaired requires a high degree of judgment in estimating relevant future cash flows, based on assumptions about the future market prices, production output and discount rates.

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into cash generating units (a “CGU”), which are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. Determination of what constitutes a CGU is subject to management’s judgment. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

Assets held for sale

The Company may record assets held for sale if the carrying amount of assets is expected to be recovered through a sale transaction rather than through continued use. Evaluating when to record an asset as held for sale requires judgment about the outcomes of future economic events and estimates concerning the likelihood of sale, timing of sale and fair value less costs of disposal of the asset.

Decommissioning provision

The Company has obligations in respect of decommissioning its oil and natural gas properties. The present value of the obligation is calculated based on estimated future cash flows, timing of remediation activities, estimated inflation rate and the risk-free discount rate applied. Assumptions, based on current economic factors which management believes are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors, including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration.

Onerous contract provision

A contract is considered to be onerous when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The determination of when to record a provision for an onerous contract is a complex process that involves management judgment about outcomes of future economic events and estimates concerning the nature, extent and timing of expected future cash flows and discount rates related to the contract.

Valuation of derivative financial instruments

The calculation of the fair value of derivative financial instruments is estimated by discounting the difference between the contractual price and the current forward price for the residual maturity of the contract using a risk-free interest rate (based on Government of Canada bonds). Estimated amounts may differ from what will eventually be realized based on subsequent fluctuations in commodity prices.

Share-based compensation

The expense recorded for the time-based and performance share awards is dependent on the number of awards that become payable and management’s assessment of the performance multiplier. Changes to the inputs and estimates when fair valuing the awards, the forfeiture rate or to the estimates used in determining the performance multiplier may result in material fluctuations in the expense.

Income taxes

The calculation of deferred income tax assets and liabilities is based on management’s interpretation of applicable laws, regulations, relevant court decisions and estimates regarding the timing of reversals of temporary differences.

Liquidity

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company.

CHANGES IN ACCOUNTING POLICIES AND RECENT PRONOUNCEMENTS

For the year ended December 31, 2017, there were no accounting policy changes that had a material effect on the reported earnings or net assets of the Company.

Future Accounting Pronouncements

In July 2014, the IASB finalized the remaining elements of IFRS 9 “Financial Instruments”, which includes new requirements for the classification and measurement of financial assets, amends the impairment model and outlines a new general hedge accounting standard. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption was permitted. The adoption of this standard on January 1, 2018 will increase the level of disclosures in the notes to the financial statements and will not have a material impact on the carrying values of the Company’s financial instruments.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts" and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. The Company has concluded that the adoption of this standard on January 1, 2018 will not have a material impact on its earnings. Additional disclosures may be required upon the implementation of IFRS 15 to enable users to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

In January 2016, the IASB issued IFRS 16 “Leases”, which replaces IAS 17 “Leases”. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted. The Company has identified a number of contracts that may be classified as leases and is evaluating the impact of the standard on the consolidated financial statements.

There are no other standards and interpretations which have been issued but not yet effective that are expected to have a material effect on the reported earnings or net assets of the Company.

ASSESSMENT OF BUSINESS RISKS

The following are the primary risks associated with the business of Cona. These risks are similar to those affecting other companies competing in the conventional oil and natural gas sector. These risks and other risks are described in more detail under the heading "Risk Factors" in the Company's annual information form for the year ended December 31, 2017. The Company's financial position and results of operations are directly impacted by these factors and include:

Operational risk associated with the production of oil and natural gas:

- Reserve risk in respect to the quantity and quality of recoverable reserves;
- Exploration and development risk of being able to add new reserves economically;
- Market risk relating to the availability of transportation systems to move the product to market;
- Commodity risk as crude oil and natural gas prices fluctuate due to market forces;
- Financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service obligations;
- Environmental and safety risk associated with well operations and production facilities;
- Blowouts, fires, power outages, explosions, railcar incident or derailment, migration of harmful substances, including oil spills and gaseous leaks, corrosion and other accidents or hazards;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection, including climate change; and
- Continued participation of Cona's lenders.

Cona seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
- Diversifying properties to mitigate individual property and well risk;
- Conducting industry-standard reviews of all property acquisitions;
- Monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
- Maintaining a hedging program to hedge commodity prices with creditworthy counterparties;
- Adhering to the Company's safety program and adhering to current industry-standard operating practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;

- Carrying industry-standard insurance;
- Establishing and maintaining resources to fund future abandonment and site restoration costs; and
- Monitoring any joint venture partners' obligations to us and cash calling for capital projects to limit the Company's credit risk.

ENVIRONMENTAL RISKS

Oil and gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the pollution of the environment, climate change and destruction of natural habitat, as well as safety risks such as personal injury. The Company works hard to understand the sensitivities of the environments in which it operates and its responsibilities from the beginning to the end. It also strives to identify the potential environmental impacts of its new projects in the planning stage and during operations. The Company conducts its operations with high standards in order to protect the environment, its employees and consultants, and the general public. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the Corporation's assessment of the remoteness of such risks, the high premiums associated with such insurance or other reasons. The payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Cona operates in jurisdictions that have regulated or have proposed to regulate greenhouse gas ("GHG") emissions and other air pollutants. While some regulations are in effect, others are at various stages of review, discussion and implementation. There is uncertainty around how any future federal legislation will harmonize with provincial regulation, as well as the timing and effects of regulations. Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada. Such regulations impose certain costs and risks on the industry. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

ADVISORIES

Abbreviations

Crude Oil		Natural Gas	
bbl	barrel	mcf	thousand cubic feet
bbl/d	barrels per day	mcf/d	thousand cubic feet per day
WTI	West Texas Intermediate	AECO	natural gas storage facility located at Suffield, AB
WCS	Western Canadian Select		

Other	
API	American Petroleum Institute
Boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
CGU	Cash generating unit
CAD	Canadian dollar
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
NYMEX	New York Mercantile Exchange
PP&E	Property, Plant & Equipment
SAGD	Steam-assisted gravity drainage
US	United States
USD	United States dollar

BOE Conversion

In this MD&A, natural gas has been converted to boe based on a conversion rate of six thousand cubic feet of natural gas to one barrel (6 mcf:1 bbl), which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

Non-IFRS Financial Measures

This MD&A makes reference to certain terms that do not have any standardized meaning prescribed by IFRS, which are referred to as “non-IFRS financial measures”. Management uses “operating netback”, “total payout ratio”, “funds from operations”, “funds from operations per boe”, “funds from operations per share”, “net debt” and “net debt to funds from operations” in the evaluation of the Company’s operating and financial performance and to provide its shareholders with a measure of the Company’s efficiency and its ability to generate cash to fund capital expenditures, pay dividends and/or repay debt. The reader is cautioned that these amounts should not be used to make comparisons to measures for other companies where similar terminology is used.

“Operating netback” is used as an indicator of operating performance and profitability relative to current commodity prices, calculated on a per boe basis. Operating netback is calculated as oil and natural gas sales (net of blending expenses) less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the period. There are no IFRS measures that are reasonably comparable to operating netback. A reconciliation of the IFRS measures and operating netbacks can be found under "Netbacks".

"Total payout ratio" is calculated as dividends paid plus capital expenditures divided by funds from operations.

"Net debt" is calculated as the principal amount drawn on bank loans, the Term Loan, the Senior Notes (if applicable), the onerous contract provision and working capital (working capital includes cash, accounts receivable, inventory, prepaid expenses and deposits, accounts payable and accrued liabilities and dividends payable), and is used by the Company to assess liquidity and general financial strength. Net debt should not be considered an alternative to, or more meaningful than, current assets or current liabilities as determined in accordance with IFRS. A reconciliation of the IFRS measures and net debt can be found under the heading "Capital Structure and Net Debt" in this MD&A.

"Funds from operations" is used by the Company to analyze operating performance and its ability to fund capital investments. Funds from operations is calculated as cash flow from operating activities (as determined in accordance with IFRS) before shares purchased for the Incentive Plan, cash settlement of Awards, decommissioning costs incurred, onerous contract provision costs incurred and changes in non-cash operating working capital. A reconciliation of the IFRS measure and funds from operations can be found in the table under the heading "Cash Flow from Operating Activities, Funds from Operations and Net Income" in this MD&A. Management considers funds from operations to be a key measure of the results generated by its principal business activities before the consideration of how those activities are financed or how the results are taxed and before decommissioning expenditures. Funds from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS.

"Funds from operations per boe" is calculated using funds from operations and boe sales volumes for the period.

"Funds from operations per share" is calculated using funds from operations and the weighted average basic and diluted shares used in calculating net income per share.

"Net debt to funds from operations" is calculated as net debt divided by the trailing four quarters funds from operations.

Forward-Looking Statements

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking statements") within the meaning of applicable Canadian securities laws. Forward-looking statements contain words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "should", or similar words suggesting future outcomes.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- Business plans and strategies;
- Capital expenditure, development and drilling programs for 2018;
- Methods and ability to finance operations, capital expenditure programs and working capital requirements;
- Anticipated oil and natural gas production levels for 2018;

- Timing and success of development and exploitation activities;
- Future oil and natural gas prices for 2018;
- Future costs, including operating, transportation, corporate and change of control costs and royalty rates for 2018;
- Future funds from operations (including and excluding hedging) for 2018; and
- Estimated future income tax deductions.

In addition, statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

With respect to forward-looking statements contained in this MD&A, management has made assumptions regarding future production levels; future oil and natural gas prices; future operating costs; the timing and amount of capital expenditures; the ability to obtain financing on acceptable terms; the availability of skilled labour and drilling and related equipment; general economic and financial market conditions; continuation of existing tax and regulatory regimes; and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, substantial capital requirements, uncertainties inherent in estimating quantities of reserves and resources, the extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time, the need to obtain regulatory approvals on projects before development commences, environmental risks and hazards and the cost of compliance with environmental regulations including those relating to climate change, aboriginal claims, inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions, potential cost overruns, variations in foreign exchange rates, diluent supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, credit risks associated with counterparties, the failure of the Company or the holder of licenses, leases and permits to meet requirements of such licenses, leases and permits, reliance on third parties for pipelines and other infrastructure, changes in royalty regimes, failure to accurately estimate decommissioning costs, inaccurate estimates and assumptions by management, effectiveness of internal controls, the potential lack of available drilling equipment and other restrictions, failure to obtain or keep key personnel, title deficiencies with the Company’s assets, geo-political risks, risks that the Company does not have adequate insurance coverage, risk of litigation and risks arising from future acquisition activities. The foregoing risks and other risks are described in more detail in the Company’s annual information form for the year ended December 31, 2017. Readers are cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved may vary from the information provided herein and the variations could be material. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there is no representation by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements. Furthermore, the forward-looking statements contained in this MD&A are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

ADDITIONAL INFORMATION

Additional information about Cona, including Cona's consolidated financial statements and notes thereto, and Cona's annual information form for the year ended December 31, 2017, is available on Cona's website at www.conaresources.com or under the Company's profile on SEDAR at www.sedar.com.