Q3 2017 Management's Discussion and Analysis

CHINOOK energy inc

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The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. and its subsidiaries, (collectively, "our", "we" or "us") for the three and nine months ended September 30, 2017 and 2016 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three and nine months ended September 30, 2017 and 2016 (the "Interim Financial Statements") and our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2016 and 2015. This MD&A is based on information available as at November 9, 2017.

The term "third quarter" or "year to date" or similar terms are used throughout this document and refer to the three or nine months ended September 30, 2017, respectively. The term "current reporting periods" or similar terms are used throughout this document and refer to both the three and nine months ended September 30, 2017, in this respective order. The term "same period(s) of 2016" or similar terms are used throughout this document and refer to either the three or (and) nine months ended September 30, 2016, depending on the 2017 period(s) under discussion.

This MD&A contains measures which are not prescribed by International Financial Reporting Standards and, therefore, may not be comparable with the calculations of similar measures presented by other companies ("non-GAAP measures"). Statements throughout this MD&A that are not historical facts may be considered "forward-looking statements". Readers should read the advisories under the headings "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2016 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The Interim Financial Statements have been prepared in accordance with International Accounting Standard 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board.

All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per unit amounts or as otherwise noted.

Introduction to Chinook

We are a Calgary-based upstream oil and natural gas company whose main business activities include exploration, development and production of natural gas liquids and natural gas. We are focused on realizing per share growth from our large contiguous Montney liquids-rich natural gas position at our Birley/Umbach property in northeast British Columbia ("BC").

We are incorporated under the laws of the Province of Alberta, Canada. Our common shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "CKE". Our head office and principal address is Suite 1000, 517 – 10th Avenue S.W., Calgary, Alberta, Canada T2R 0A8.

Subject Asset Conveyance, Disposition and Craft Share Distribution

On June 10, 2016, we conveyed the majority of our Alberta oil and natural gas assets, excluding our Montney assets, and the associated decommissioning obligations in addition to $0.9 million cash (collectively, the "Subject Assets") to Tournament Exploration Ltd., which subsequently changed its name to Craft Oil Ltd. and then Craft Oil Inc. (“Craft”), a private Calgary-based petroleum and natural gas production company, for 70% of its issued and outstanding common shares pursuant to an asset purchase and sale agreement dated and effective May 1, 2016.

In October 2016, Craft sold its legacy properties in addition to certain properties included in the Subject Assets. On December 12, 2016, we completed the distribution of all of the Craft Oil Ltd. shares held by us to our shareholders as at the close of business pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "Craft Share Distribution"). Following the Craft Share Distribution, our control over Craft’s operations ceased. As a result, for any period(s) subsequent to December 12, 2016, the accounts of Craft are not reflected in our financial and operating results.

Generally, the current reporting periods’ changes in operating results and their corresponding financial measures, in comparison to the same periods of 2016, result from the Subject Assets and Craft’s legacy operations as either sold in October 2016 or as included in the Craft Share Distribution.

Financial and Operating Highlights

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
OPERATIONS				
Production (1)				
Natural gas liquids (boe/d)	**405**	599	**442**	645
Natural gas (mcf/d)	**14,109**	28,972	**17,051**	25,666
Crude oil (bbl/d)	**19**	1,036	**22**	874
Average daily production (boe/d)	**2,776**	6,464	**3,306**	5,798
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 42.07**	$ 10.67	**$ 46.22**	$ 21.78
Average natural gas price ($/mcf)	**$ 1.20**	$ 2.22	**$ 2.31**	$ 1.71
Average oil price ($/bbl)	**$ 51.49**	$ 57.31	**$ 57.52**	$ 48.55
Netback (2)				
Average commodity pricing ($/boe)	**$ 12.61**	$ 20.14	**$ 18.49**	$ 17.31
Royalty recovery (expense) ($/boe)	**$ 0.52**	$ (0.77)	**$ 0.09**	$ (0.74)
Realized gains on derivative contracts ($/boe)	**$ 6.54**	$ 1.84	**$ 2.70**	$ 0.72
Net production expense ($/boe) (2)	**$ (12.32)**	$ (12.61)	**$ (11.77)**	$ (14.07)
Operating Netback ($/boe) (2)	**$ 7.35**	$ 8.60	**$ 9.51**	$ 3.22
Wells Drilled (net)				
Total natural gas wells drilled (net)	**-**	-	**3.63**	-
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 3,351**	$ 11,518	**$ 16,772**	$ 26,312
Adjusted funds (outflow) from operations (2)	**$ 647**	$ 1,894	**$ 3,878**	$ (2,717)
Per share - basic & diluted ($/share)	**$ -**	$ 0.01	**$ 0.02**	$ (0.01)
Net (loss) income	**$ (3,923)**	$ (35,905)	**$ 4,246**	$ (61,200)
Per share - basic and diluted ($/share)	**$ (0.02)**	$ (0.17)	**$ 0.02**	$ (0.28)
Capital expenditures	**$ 14,733**	$ 661	**$ 31,791**	$ 5,034
Net surplus (2)	**$ 3,616**	$ 7,217	**$ 3,616**	$ 7,217
Total assets	**$ 155,799**	$ 274,674	**$ 155,799**	$ 274,674
Common Shares (thousands)				
Weighted average during period				
- basic	**217,115**	216,287	**216,721**	215,666
- diluted	**217,115**	216,287	**217,144**	215,666
Outstanding at period end	**217,115**	216,443	**217,115**	216,443

(1) Throughout this MD&A our production is presented in either barrels of oil ("bbl"), thousands of cubic feet ("mcf") or barrels of oil equivalent ("boe"); production per day is presented as bbl/d, mcf/d, and boe/d, respectively; commodity prices or revenues and expense per sales are presented as $/bbl, $/mcf, and $/boe, respectively. Production volumes and sales volumes are equal and are used interchangeably throughout this MD&A.

(2) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Operations

Petroleum and Natural Gas Production Volumes

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Natural gas liquids (boe/d)	**405**	599	**442**	645
Natural gas (mcf/d)	**14,109**	28,972	**17,051**	25,666
Crude oil (bbl/d)	**19**	1,036	**22**	874
Total (boe/d)	**2,776**	6,464	**3,306**	5,798

Total Production Volumes

During the current reporting periods, our production decreased by 3,688 boe/d and 2,492 boe/d compared to the same periods of 2016. A longer than scheduled turnaround at the Enbridge McMahon gas plant (the "McMahon Plant") restricted our July volumes. This turnaround, which began in June, resulted in July's production being 3,160 boe/d lower than May. Our Montney production was back on-stream in mid-July immediately following the completion of the McMahon Plant turnaround. We averaged 4,850 boe/d from July 18 – 24, 2017 but these volumes were subsequently impacted by further McMahon Plant and other third party restrictions**.** As our operations are now focused in northeastern BC, there were increases during the current reporting periods in the weighted average production volume ratios flowing to the McMahon Plant and certain other third party pipelines, compared to the same periods in 2016. With these increased ratios, the effect of these restrictions was more significant to our current periods' reported production volumes. Our 2014 strategic acquisition of the 12" Aitken Creek pipeline that passes through our Birley lands and connects our Martin Creek and Black Conroy production to a third party downstream sales pipeline provides us with optionality with future area infrastructure development, to flow directly to the Alliance pipeline with access to Chicago markets. Additional connections in the immediate area can provide alternate access to markets such as BC Station 2 via Enbridge's T-North pipeline or connect to TCPL's North Montney expansion when complete in 2019 or 2020.

We continue to see the benefits of our Birley drilling programs in our production volumes for the current reporting periods including the three (2.75 net) Birley/Umbach wells brought on-stream in mid-February 2016, on the commissioning of our 25 mmcf/d compressor station; however, initial production rate declines, as expected, from these and other previously drilled wells in that area, excluding days where production was restricted, resulted in lower production volumes of approximately 260 boe/d compared to the same periods of 2016. Also contributing to the decreases in volumes were the Subject Assets and Craft's legacy properties that, last year, were either sold or included in the Craft Share Distribution. In addition, during the first quarter of 2017, we also sold our East Gold Creek property with associated production of 100 boe/d for net proceeds of $10.6 million.

Partially offsetting the above production decreases, during the current reporting periods, but excluding days the following wells were not on-stream or restricted, we added 1,450 boe/d of production from three (2.64 net) wells at Birley/Umbach which were drilled during the fourth quarter of 2016 and brought on-stream late in the first quarter of 2017. As a result of the production from these new wells we increased our Birley/Umbach year to date production volumes in comparison to the same period of 2016. Contributing to the current reporting periods' production volumes were reactivations of our Martin Creek and Black Conroy fields late during the third quarter of 2016 and a reactivation of our Boundary Lake North field during the first quarter of 2017. These BC well reactivations resulted from a new natural gas handling agreement. We produced an additional 725 boe/d and 980 boe/d from these three fields during the current reporting periods compared to the same periods of 2016. As a result of our increased BC production, during the second quarter of 2017 we were refunded our $3.0 million Liability Management Ratio deposit from the BC Oil & Gas Commission.

During the third quarter, we completed and tied-in our four (3.63 net) horizontal Montney gas wells at Birley/Umbach. Two of the wells were drilled with approximately 1,600 metre lateral lengths with 30 frac stages, while the other two were drilled with approximately 1,800 metre lateral lengths with 35 frac stages. All the wells were completed with 52 metre frac spacing and 55 tonnes of proppant per stage. Final 24 hour test rates per well averaged 1,800 boe/d including 300 bbl/d of condensate. Two of these wells (1.63 net) came on-stream at the beginning of October 2017; however, due to our existing 25 mmcf/d raw natural gas Birley/Umbach facility capacity, these new wells are currently flowing at restricted rates. Upon the completion of this facility's expansion to 50 mmcf/d, which is expected late in the fourth quarter, we plan on releasing these flow restrictions and bringing the other two (2.00 net) wells on-stream.

Natural Gas and Natural Gas Liquids Production (“NGL”) Volumes

Natural gas and its associated liquids production for the current reporting periods decreased compared to the same periods of 2016 because of a longer than scheduled McMahon Plant turnaround that continued into mid-July and other third party restrictions which halted the majority of our concentrated BC production in addition to the absence of the Subject Assets and the Craft legacy properties. Partially offsetting these decreases was higher production from the reactivation of wells in Martin Creek, Black Conroy and Boundary Lake North, BC. Our Birley/Umbach area development program and resulting higher year to date production volumes also partially offset the decrease compared to the same period of 2016.

Crude Oil Production Volumes

Our crude oil production volumes for the current reporting periods decreased compared to the same periods of 2016. During 2016, upon completion of the Craft Share Distribution, we transformed into a pure Montney play company focused on liquids-rich natural gas in our Birley/Umbach area. Consequently, our crude oil production has decreased during the current reporting periods compared to the same periods of 2016.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended September 30		Nine months ended September 30	
($ thousands, except per unit amounts)	**2017**	2016	**2017**	2016
Natural gas liquids sales	**$ 1,566**	$ 588	**$ 5,580**	$ 3,851
$/boe	**42.07**	10.67	**46.22**	21.78
Natural gas sales	**$ 1,561**	$ 5,926	**$ 10,757**	$ 12,011
$/mcf	**1.20**	2.22	**2.31**	1.71
Oil sales	**$ 92**	$ 5,462	**$ 351**	$ 11,633
$/bbl	**51.49**	57.31	**57.52**	48.55
Petroleum & natural gas revenue	**$ 3,219**	$ 11,976	**$ 16,688**	$ 27,495
$/boe	**12.61**	20.14	**18.49**	17.31

Our petroleum and natural gas revenues decreased for the current reporting periods compared to the same periods of 2016. For the third quarter, this decrease was the result of both lower production volumes and realized natural gas pricing. However, despite lower production volumes, during the current year to date the decrease in petroleum and natural gas revenue was partially offset by both higher realized natural gas and its associated liquids pricing. As previously discussed, the lower production volumes resulted from third party restrictions as well as the absence of both the Subject Assets and Craft legacy properties. The changes in our realized commodity pricing were due to natural gas and crude oil benchmarks. Further contributing to these realized commodity pricing changes was the unfavorable effect of a higher ratio of natural gas production relative to total production volumes that occurred with our transition to a pure Montney play company. This is because natural gas, on a heating equivalent basis, receives a lower price.

Benchmark Prices

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Natural gas liquids				
Canadian light sweet (1) ($/bbl)	**$ 57.15**	$ 54.19	**$ 60.57**	$ 50.14
Natural gas				
AECO gas (2) ($/mcf)	**$ 1.61**	$ 2.36	**$ 2.36**	$ 1.87
BC Westcoast Station 2 (3) ($/mcf)	**$ 0.99**	$ 1.98	**$ 1.97**	$ 1.53
Chicago City Gate(4) ($/mcf)	**$ 2.91**	$ 2.80	**$ 3.04**	$ 2.34

(1) Central market point for Canadian crude oil.
(2) Central market point for Canadian natural gas.
(3) Market point for BC natural gas.
(4) Market point for mid-Eastern United States natural gas.

NGL Pricing

During the current reporting periods, consistent with higher Canadian light sweet oil and various other liquids and condensate benchmarks, our realized NGL pricing of $42.07/boe and $46.22/boe increased compared to the same periods of 2016. Our NGL price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however, we benchmark our liquids in reference to Canadian light sweet oil. The ratio of our NGL price relative to Canadian light sweet oil was 74% and 76% for the current reporting periods which increased compared to approximately 48% and 54% for the same periods of 2016, after excluding the effect of the BC Government reclassifying a natural gas well to a crude oil well during the comparative periods. Had the BC Government not reclassified this well the comparative periods' NGL revenues and pricing would have been $2.0 million or $26.21/boe and $5.2 million or $27.05/boe. These higher ratios were caused by the prices of a range of liquids and condensates increasing at a greater rate than the increase in the Canadian light sweet benchmark. These increased ratios were also due to the weighted average production volumes contributed from our Birley/Umbach area relative to our total production volumes.

Natural Gas Pricing

Our realized natural gas price of $1.20/mcf during the third quarter significantly decreased compared to the $2.22/mcf for the same quarter of 2016. Inversely, our natural gas price of $2.31/mcf during the year to date increased compared to $1.71/mcf for the same period of 2016. These realized natural gas pricing changes are due to both changes in benchmark pricing and in the weighted average ratio of natural gas production sold at each benchmark price relative to total natural gas production. Generally, the changes in our current reporting periods' realized natural gas prices correspond to the changes in the Station 2 benchmark. We sell the majority of our current reporting periods' natural gas production at that benchmark price. However, the comparative periods' realized natural gas prices resulted from both the Subject Assets and the Craft legacy properties natural gas production being predominately sold at the AECO benchmark. As we transitioned during December 2016 to a pure Montney play company, the AECO benchmark no longer became significant to our current periods' realized natural gas sales prices. Rather, in the current reporting periods, compared to the same periods of 2016, we sell a larger ratio of our natural gas production at the Chicago City Gate benchmark relative to our total natural gas production. Specifically, during the third quarter we sold 28% of our natural gas production at the Chicago City Gate benchmark compared to 17% during the same quarter of 2016. Selling our natural gas at Chicago City Gate benchmark pricing results in us realizing a significant premium compared to Station 2 pricing. This effect partially offsets the record low third quarter Station 2 benchmark price not observed in over two decades as attributable to temporary third party pipeline restrictions which are causing an increase in the overall pressure on the BC system and a surplus of natural gas at Station 2. We remain optimistic that Station 2 pricing will increase through the upcoming winter season.

Royalties

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Royalty (recovery) expense	**$ (132)**	$ 458	**$ (84)**	$ 1,183
Per sales ($/boe)	**$ (0.52)**	$ 0.77	**$ (0.09)**	$ 0.74
Percent of revenues (%)	**(4)**	4	**(1)**	4

For the current reporting periods, our royalties decreased on an overall basis, per boe and as a percentage of revenue, compared to the same periods of 2016. These decreases primarily resulted from lower production volumes as caused by the Subject Assets and Craft legacy properties which are located throughout Alberta with higher royalty rates associated with crude oil volumes. The current reporting periods' recoveries were caused by adjustments to our previous Alberta Gas Cost Allowance ("GCA") estimates. Royalties in Alberta are no longer significant to our operations. Also, we were recently granted $1.0 million of royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). This program provides credits on our Birley/Umbach development only after sufficient crown royalties had been generated by specific wells. We recognized $0.2 million and $0.7 million of this credit through a decrease to our royalties during the current reporting periods. We further anticipate receiving additional Infrastructure Program royalty credits during 2017 for certain Birley/Umbach wells, including the three wells brought on-stream in mid-March. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program where we currently have $3.5 million in remaining royalty credits. The eight (6.86 net) Birley/Umbach wells that have qualified for this credit program bear a minimum crown royalty rate of

3% prior to applying the credits from the Infrastructure Program. We expect our latest four (3.63 net) Birley/Umbach wells to also quality for BC's Natural Gas Deep Well Royalty Credit Program. During the remainder of 2017 and through 2018 we are forecasting nominal BC crown royalties as a result of these credit programs combined with being a BC Montney focussed play. Overriding and freehold royalties will continue to be payable.

Financial Commodity Price Contracts

To help mitigate commodity price risk, we enter into financial commodity price contracts which assist us in better managing our future adjusted funds from operations. This provides more certainty within determined commodity price ranges as to what we will receive on a portion of our liquids and/or natural gas sales volumes. While these financial contracts may have opportunity costs when commodity benchmarks exceed the contracted prices, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Also the terms of our debt facility agreement, if we have net debt or debt draws of either up to $9.0 million or in excess of $9.0 million, requires us to enter into commodity price contracts covering no less than 30% or 50%, respectively, of our forecasted twelve month combined production volumes. We continuously review the need or requirement to utilize financial contracts.

Our unsettled swap commodity price contracts are reported at their approximated fair values on the date of the Interim Financial Statements. These estimated fair values are partially determined through the difference in the referenced market forward price of the respective commodity over the remaining periods of the contracts as compared to our received price multiplied by the remaining notional volumes. Volatility in the commodity price and any decrease in the remaining notional volumes will result in changes in the fair value of our derivative contracts from one period to the next. The change in the fair values between reporting periods are recognized in net income (loss) as unrealized gains or losses on commodity price contracts. Realized gains or losses from these financial commodity price contracts are recognized in net income (loss) over their term.

For the current and comparative reporting periods, we had the following realized and unrealized gains and losses from our commodity price contracts:

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Realized gain on commodity price contracts	**$ (1,669)**	$ (1,093)	**$ (2,438)**	$ (1,161)
Unrealized (gain) loss on commodity price contracts	**280**	(1,647)	**(1,307)**	1,929
Total	**$ (1,389)**	$ (2,740)	**$ (3,745)**	$ 768
Realized gain on commodity price contracts ($/boe)	**$ 6.54**	$ 1.84	**$ 2.70**	$ 0.72

During the current reporting periods, we realized gains on our AECO price contracts as this benchmark was lower than our received price on these contracts. If we had included these settlements in our natural gas revenues, we would have reported adjusted natural gas sales prices for the current reporting periods of approximately $2.49/mcf and $2.83/mcf compared to our reported prices of $1.20/mcf and $2.31/mcf.

Our unrealized loss and gain for the current reporting periods reflect the change in the forward AECO price relative to the fixed contracted prices and the change in notional volumes remaining on the contracts. As at September 30, 2017, our commodity price contracts had a combined estimated current asset fair value of $1.2 million with the following terms:

Indexed Price	Notional Volumes	Company's Received Price	Remaining Contractual Term
AECO	7,500 GJ/d	$3.205/GJ	October 1, 2017 to December 31, 2017
AECO	4,000 GJ/d	$2.50/GJ	October 1, 2017 to October 31, 2017

With the combined notional volumes from the above two outstanding commodity price contracts, we will receive a weighted average price of $3.04/GJ on approximately 55% of our 2017 revised guidance natural gas production volumes (see "Outlook).

At September 30, 2017, because we had no outstanding debt and were in a net surplus position of $3.6 million, we were not required as a condition of our credit facility to maintain a minimum level of commodity price contracts covering at least 30% (50% if net debt or draws on debt are in excess of $9.0 million) of our forecasted twelve month combined production volumes.

Net Production Expense

($ thousands, except where noted)	Three months ended September 30 2017	2016	Nine months ended September 30 2017	2016
Production & operating	**$ 3,373**	$ 8,050	**$ 11,319**	$ 24,362
Less:				
Processing & gathering revenues	**(226)**	(553)	**(694)**	(2,010)
Net production expense [(1)]	**$ 3,147**	$ 7,497	**$ 10,625**	$ 22,352
Net production expense ($/boe) [(1)]	**$ 12.32**	$ 12.61	**$ 11.77**	$ 14.07
Production expense ($/boe)	**$ 13.21**	$ 13.54	**$ 12.54**	$ 15.34

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Production and operating expense for the current reporting periods decreased in total and on a per boe basis from the same periods of 2016. These decreases were due to the Subject Assets and Craft legacy properties, which on a boe basis had relatively higher operating costs. Although we increased our year to date volumes at Birley/Umbach and this added to our total operating costs, the synergies achieved through the impact of increased volumes relative to our fixed operating costs had the effect of further decreasing our operating costs on a per boe basis.

During the current reporting periods, we also realized benefits related to a gas handling agreement executed late in the third quarter of 2016 which impacts the majority of our BC natural gas production. The agreement has significantly improved go-forward drilling economics, bringing base production back online and providing gas handling capacity for growth volumes as well as reducing operating costs by approximately $2.70/boe. Early in the first quarter of 2017, these improved economics allowed us to reactivate our Boundary Lake North property. We expect our on-going operations to incur production costs under $10/boe once production volumes from our most recent 2017 four well drilling program are brought on-stream at full capacity and subject to our ability to maintain our production volumes. The current reporting periods' operating costs on a per boe basis were higher than expected due in part to lower production volumes, caused by the previously mentioned turnaround restrictions, relative to our fixed operating costs. Our year to date fluid hauling costs more than doubled due to road bans caused by wet weather conditions resulting in partial truck loads in addition to higher than forecast water production and related hauling costs. We also incurred start-up costs to reactivate our Boundary Lake North field in addition to various well restarts and optimizations at our Martin Creek and Black Conroy fields. Although these fields' produced at a level that exceeded our expectation, their higher operating cost structure relative to our Birley/Umbach field further contributed to higher unexpected operating costs on a boe basis. Finally, we incurred seasonal costs including the repair and maintenance of our processing plants and our Birley/Umbach access road. Combined, these seasonal, reactivation or optimization costs were in excess of $0.5 million.

The processing and gathering revenue for the current reporting periods decreased compared to the same periods of 2016. This decrease was due to the previously mentioned volume restrictions in addition to the processing and gathering assets included within the Subject Assets and Craft legacy properties that, last year, were either sold or included in the Craft Share Distribution, as partially offset by new toll revenue from our 12" Aitken Creek pipeline.

Operating Netback

The following table outlines the calculation of our operating netback[(1)]:

Per sales ($/boe)	Three months ended September 30 2017	2016	Nine months ended September 30 2017	2016
Realized sales price	**$ 12.61**	$ 20.14	**$ 18.49**	$ 17.31
Royalty recovery (expense)	**0.52**	(0.77)	**0.09**	(0.74)
Realized gain on commodity price contract	**6.54**	1.84	**2.70**	0.72
Net production expense [(1)]	**(12.32)**	(12.61)	**(11.77)**	(14.07)
Operating netback [(1)]	**$ 7.35**	$ 8.60	**$ 9.51**	$ 3.22

(1) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Our operating netback decreased during the third quarter compared to the same quarter of 2016, due to significantly lower realized natural gas sales pricing. Inversely, our operating netback significantly increased for the year to date compared to the same period of 2016, due to both higher natural gas production and its associated liquids' pricing. Both current reporting periods benefited from increases in realized gains from commodity price contracts. As already discussed, both current reporting periods' production was impacted due to a longer than scheduled McMahon Plant turnaround and other third party restrictions. On a boe basis, despite the effect of these lower volumes, our transition to a pure Montney play with its associated lower cost structure resulted in decreases to our current reporting periods' net production expenses. Also, for the current reporting periods, compared to the same periods of 2016, BC Government royalty grants and a GCA adjustment decreased our royalties. These changes have been previously discussed.

General & Administrative ("G&A") Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
G&A expense before recoveries	**$ 1,885**	$ 3,538	**$ 6,640**	$ 10,287
Recoveries	**(712)**	(744)	**(2,320)**	(3,536)
G&A expense	**$ 1,173**	$ 2,794	**$ 4,320**	$ 6,751
Per sales ($/boe)	**$ 4.59**	$ 4.70	**$ 4.79**	$ 4.25

The comparative periods includes $0.8 million and $0.9 million of Craft G&A expenses which were absent in the current reporting periods as a result of the Craft Share Distribution.

During the current reporting periods, as a result of our continued headcount reductions and subleasing a portion of our Calgary head office space, we evaluated that approximately one-half of our office lease contract was onerous. This resulted in a one-time onerous contract non-cash charge of $1.6 million (see "Onerous Contract") as offset against a provision. As a result of this recognition, $0.2 million of rent expenditures for the current reporting periods that previously would have been reported as G&A expense instead reduced our onerous contract provision. Future rent expenditures associated with the onerous portion of this lease will continue to be recognized as a decrease to the provision until the lease expires in June 2019. If current rental market conditions remain the same or similar, we anticipate lower rent costs commencing in 2019 upon our lease expiration.

We have continued to focus on improving our G&A cost structure through cost cutting initiatives and we continue to assess our G&A expenses and make reductions where feasible. We have realized lower G&A expenses resulting from lower staffing costs due to reductions in headcount, reduced information system costs and less reliance on consultants and professional services. We also realized savings for the entire year to date from cost cuts reported during the prior year including reduced compensation for officers and directors in addition to reduced employee benefits. However, partially offsetting these decreases were lower G&A recoveries. With both lower compensation and operating costs combined with a shift to more focused operated properties, our capitalized G&A, operating and other associated G&A recoveries decreased by $1.2 million during the year to date compared to the same period of 2016. As a result, excluding the effects of both Craft G&A and the onerous contract, our G&A expenses decreased $0.7 million and $2.5 million during the current reporting periods compared to the same periods of 2016.

Despite a decrease in our overall G&A expense, G&A on a boe basis increased during the year to date as a result of the previously discussed lower production volumes. With revised guidance production volumes and the effect of a portion of our rent expenditures reducing the onerous contract provision, we are revising our anticipated 2017 G&A expense from $4.00/boe to $4.15/boe.

Transaction, Distribution and Severance Costs

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Transaction, distribution & severance costs	**$ 163**	$ 120	**$ 671**	$ 1,740

Severance costs incurred during the current and comparative reporting periods related to staffing reductions resulting from a continuing assessment of our staffing requirements and the simplification of our current operations. During the third quarter of 2016, costs were also incurred in connection with the distribution of Craft shares to our shareholders. Prior to then, as included in the comparative year to date period, transaction costs were incurred in connection with the conveyance of the Subject Assets to Craft and the corresponding Craft acquisition.

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Exploration & evaluation expense	**$ 66**	$ 151	**$ 261**	$ 968

Exploration and evaluation expense during the current reporting periods was in respect of geological and geophysical salaries and exploratory lease rental costs. This expense decreased during the current reporting periods compared to the same periods of 2016 because of lower geological and geophysical salaries resulting from headcount reductions and the Subject Assets and Craft legacy properties that, last year, were either sold or included in the Craft Share Distribution.

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

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Depletion, depreciation & amortization	**$ 2,467**	$ 7,672	**$ 8,474**	$ 21,460
Depletion per sales ($/boe)	**$ 7.70**	$ 11.21	**$ 7.84**	$ 11.69

DD&A expense decreased on an overall and boe basis during the current reporting periods compared to the same periods of 2016. The overall DD&A decreases resulted from lower depletion rates, production volumes and amortization. The depletion rate decreases were due to the higher depletion rate associated with both the Subject Assets and Craft legacy properties that, last year, were either sold or included in the Craft Share Distribution. These decreased rates were also caused by an increase in the December 31, 2016 measure of our on-going operations' proved plus probable reserves. The most recently drilled Birley/Umbach wells were accretive to our proved plus probable reserves combined with lower development costs than estimated in our year-end reserve report. This also lowered our depletion rates in the current reporting periods. Amortization expense during the current reporting periods decreased $0.5 million and $1.5 million compared to the same periods of 2016. These decreases were caused by undeveloped lands included in the Subject Assets in addition to other dispositions.

Gain on Dispositions of Properties

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Gain on dispositions of properties	**$ -**	$ (161)	**$ (10,926)**	$ (6,020)

During the year to date, we completed the sale of certain non-core assets located in the Knopcik/Pipestone and East Gold Creek areas of northwestern Alberta for net consideration of $17.8 million after customary closing adjustments. These dispositions resulted in Assets and Liabilities Held for Sale at December 31, 2016. The comparative period's gain was from the sale of properties in the Gold Creek area of northeastern Alberta and the Enchant area of southcentral Alberta for proceeds of $8.1 million.

Share-Based Compensation

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Share-based compensation	**$ 182**	$ 333	**$ 691**	$ 1,685

We granted share options and restricted awards during the second quarter of 2017. These granted awards had a lower estimated fair value compared to previous years' grants. We last granted awards, including performance awards, during 2015 whose fair values have since been largely amortized. Combined, this resulted in a decrease in share-based compensation for the current reporting periods compared to the same periods of 2016.

Onerous Contract

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Onerous contract	**$ 1,561**	$ -	**$ 1,561**	$ -

During the current reporting periods, we recognized a $1.6 million non-cash charge as offset against a provision caused by the onerous portion of our Calgary head office lease contract. The provision represents the present value of the difference between the minimum future lease payments we are obligated to make under the onerous portion of the non-cancellable lease contract, which is classified as an operating lease, and estimated recoveries discounted using a risk-free discount rate of 1.58%. The onerous contract provision is estimated to be settled during future reporting periods through to June 2019. During the third quarter, $0.2 million of expenditures allocated to the onerous portion of the office lease, reduced the provision to $1.4 million as at September 30, 2017.

Deferred Customer Obligation Amortization

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Deferred customer obligation amortization	**$ (363)**	$ -	**$ (363)**	$ -

During the current reporting periods, a customer transferred to us a section of pipeline which connected our 12” Aitken Creek pipeline, located in northeast BC, to a third party pipeline. We estimated the fair value of this connecting pipeline at $2.8 million using both contracted and interruptible transportation toll revenues discounted using a range from 15% to 30%. The corresponding deferred customer obligation will be amortized over the term of the agreement, which expires October 31, 2020, pursuant to which we are contractually obligated to provide this customer with access to a portion of the Aitken Creek pipeline. As a result, during the current reporting periods we amortized $0.4 million of the deferred customer obligation.

Other Losses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Other losses	**$ 150**	$ 34	**$ 626**	$ 636

During the current and comparative reporting periods, we incurred a fee for a take or pay processing agreement in respect of which we did not deliver the required liquids. We have partially mitigated our continued exposure to this agreement’s costs at least through to the first quarter of 2018. We continue to evaluate other cost mitigation options.

Financing Expenses

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Interest & financing (income) charges	**$ (60)**	$ 381	**$ (184)**	$ 493
Accretion of decommissioning obligation and onerous contract	**177**	688	**515**	1,818
Total	**$ 117**	$ 1,069	**$ 331**	$ 2,311

We reported interest & financing income of $0.1 million and $0.2 million during the current reporting periods as our interest earned from cash on hand was greater than standby and initial financing fees we incurred on our undrawn credit facility. During the comparative periods, interest & financing charges were $0.4 million and $0.5 million as interest from our cash on hand was more than offset by interest on the debt held by Craft.

The accretion charges during the current reporting periods decreased compared to the same periods of 2016. These decreases resulted from last year’s $69.7 million reduction in decommissioning obligations mostly caused by the Subject Assets that were either sold or included in the Craft Share Distribution.

Net & Comprehensive (Loss) Income

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Weighted average shares outstanding - basic (thousands)	**217,115**	216,287	**216,721**	215,666
Dilutive impact of share based awards (thousands)	**-**	-	**423**	-
Weighted average shares outstanding - diluted (thousands)	**217,115**	216,287	**217,144**	215,666
Net & comprehensive (loss) income	**$ (3,923)**	$ (35,905)	**$ 4,246**	$ (61,200)
Per share - basic & diluted ($/share)	**$ (0.02)**	$ (0.17)	**$ 0.02**	$ (0.28)

For the third quarter we are reporting a decrease in net loss, whereas for the year to date we are reporting an increase in net income compared to the same periods of 2016. These favorable changes for the current reporting periods reflect a lower cost structure associated with our transition. For the year to date, a $10.9 million gain on the disposition of non-core properties, higher commodity pricing and a $3.7 million gain on commodity price contracts also increased net income compared to the same period of 2016. Unfortunately, significantly lower natural gas pricing combined with restricted volumes and the onerous contract charge resulted in the third quarter's net loss.

Absent in the current reporting periods but as included in the comparative periods are net losses from the Craft operations. These net losses included $52.0 million of impairment charged against the Craft assets but partially offset by the comparative periods' $14.2 million and $17.6 million of net losses attributable to the non-controlling interest. This impairment charge also resulted in a $7.1 million deferred income tax recovery for the third quarter of 2016.

Capital Resources, Capital Expenditures and Liquidity

Since the beginning of depressed commodity prices in 2014 we have focused on capital preservation and optionality while continuing to focus our operations through non-core asset dispositions. During 2016, we completed the transition to a pure Montney play company focused on the development of liquids-rich natural gas production from our Birley/Umbach area. In disposing of or distributing non-core properties we have freed up operating funds to focus on this core area. We also completed two separate transactions during the year to date to dispose of non-core assets for a combined $17.8 million after customary adjustments with associated production volumes of 100 boe/d. To fund the $7.6 million remaining 2017 capital program we will use our net surplus of $3.6 million at September 30, 2017 as supplemented by our expected fourth quarter of 2017 adjusted funds from operations and if necessary draw on a portion of our $18.0 million demand credit facility. During the fourth quarter of 2017, as a result of the test results of our four (3.63 net) most recently drilled and completed Birley/Umbach wells, our demand credit facility was increased from $8.0 million to $18.0 million. We anticipate a $2.7 net debt balance at December 31, 2017. We continue to evaluate options as supplemented by future adjusted funds from operations to finance various 2018 capital program scenarios which are under consideration.

For the year to date, we financed capital expenditures from adjusted funds from operations, a decrease in non-cash working capital and property dispositions.

Adjusted Funds (Outflow) from Operations

	Three months ended September 30		Nine months ended September 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Cash (outflow) flow from operating activities	**$ (1,352)**	$ (1,838)	**$ 3,483**	$ (7,803)
Add back (deduct):				
Change in operating non-cash working capital	**1,444**	3,337	**(997)**	(1,422)
Provision expenditures	**326**	124	**460**	3,800
Exploration & evaluation expenses	**66**	151	**261**	968
Transaction, distribution & severance costs	**163**	120	**671**	1,740
Adjusted funds (outflow) from operations (1)	**$ 647**	$ 1,894	**$ 3,878**	$ (2,717)
Per share - basic & diluted	**$ -**	$ 0.01	**$ 0.02**	$ (0.01)

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

We are reporting a year to date increase in adjusted funds from operations of $3.9 million compared to adjusted funds outflows of $2.7 million in the same period of 2016. This increase resulted from higher commodity benchmark prices and a lower cash-based cost structure for our Montney focused operations. These lower cash-based costs were also because of both the Subject Assets and Craft legacy operations with their higher associated cost structure that, last year, were either sold or included in the Craft Share Distribution. However, despite this favorable cost structure, lower realized natural gas pricing and restricted production volumes resulted in the third quarter's adjusted funds from operations of $0.6 million decreasing compared to the $1.9 million in the same quarter of 2016. Despite historically low Station 2 benchmark pricing and restricted production volumes, our third quarter adjusted funds from operations is the fifth consecutive quarter we have reported positive adjusted funds flow which coincides with our transition to a pure Montney play. Both current reporting periods benefited from $1.7 million and $2.4 million of realized gains from commodity price contracts.

Credit Facilities

	September 30 2017	December 31 2016
($ thousands)		
Long-term debt	**$ -**	$ -
Less:		
Accounts payable, accrued liabilities & other	**(17,724)**	(11,218)
Add:		
Cash and restricted cash	**15,019**	16,129
Accounts receivable	**4,534**	6,658
Prepaids & deposits	**1,787**	3,569
Net surplus (1)	**$ 3,616**	$ 15,138

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

We had a net surplus of $3.6 million at September 30, 2017 compared to $15.1 million at December 31, 2016. This decrease of $11.5 million was caused by capital, provision, exploration and evaluation expenditures and severance costs of $33.2 million net of both disposition proceeds of $17.8 million and adjusted funds from operations of $3.9 million.

During the year to date, our previous credit facility agreement was terminated and we negotiated and secured an $8.0 million demand credit facility with a Canadian chartered bank. Subsequent to September 30, 2017, this facility was amended to increase the availability to $18.0 million (the "Demand Credit Facility") with the next semi-annual review scheduled for May 31, 2018. This availability increase was secured upon submitting to the lender the test results from our recently drilled and completed wells.

At any time, the lender can request repayment of all outstanding drawn amounts resulting in any future borrowings being classified as a current liability. Changes in the availability in the Demand Credit Facility are possible, from one semi-annual review to the next, with draws in excess of availability becoming immediately payable. Borrowings incur interest at the prime rate plus an applicable margin and are collateralized by floating charges and security interests over all of our present and future properties and other assets. We currently have not made any draws on the Demand Credit Facility, but have outstanding letters of credit of $0.8 million, as secured by our lender, which reduces the available credit to $17.2 million (at September 30, 2017 - $7.2 million of available credit).

The Demand Credit Facility has a financial covenant requiring that the adjusted working capital be 1:1 at each reporting period. For the purposes of this covenant, adjusted working capital is defined as working capital excluding both current commodity price contracts and debt but including the undrawn portion of the Demand Credit Facility. In addition, the Demand Credit Facility includes operating and financial restrictions on us that include restrictions on paying dividends or repurchasing or making other distributions in respect of our securities.

As at the end of any month, if we have either up to $9.0 million or in excess of $9.0 million of net debt or Demand Credit Facility draws, within 60 days of the end of any such month, the terms of the Demand Credit Facility also require that we must enter into commodity price contracts covering no less than 30% or 50%, respectively, of our forecasted twelve month combined production volumes.

As at September 30, 2017, we were in compliance with the above financial covenant and other requirements.

As at December 31, 2016, we had guaranteed a total of $1.3 million in outstanding letters of credit through depositing an equivalent amount in cash with our lender. During the year to date, the lender released its restrictions to this cash in connection with the execution of the Demand Credit Facility.

Capital Expenditures

Our capital expenditures during the current and comparative reporting periods were as follows:

	Three months ended September 30		Nine months ended September 30	
($ thousands)	**2017**	2016	**2017**	2016
Land & lease	**$ 182**	$ 2	**$ 182**	$ 149
Drilling & completions	**10,069**	-	**22,630**	-
Facilities & equipment	**4,318**	473	**8,393**	4,083
Field expenditures	**14,569**	475	**31,205**	4,232
Capitalized G&A	**164**	186	**586**	802
Total	**$ 14,733**	$ 661	**$ 31,791**	$ 5,034
Proceeds from dispositions	**$ -**	$ 162	**$ 17,838**	$ 8,074

During the third quarter, we successfully completed and tied-in our four (3.63 net) horizontal Montney gas wells at Birley/Umbach (the a-81-F, b-90-G and 02/d-5-K, and b-14-K wells). These wells were drilled during the second quarter of 2017 with various downhole locations on our D-93-F pad. On average, each well's gross cost was $4.24 million to drill, complete and equip. Our year to date capital expenditures also include the costs to complete, equip and tie-in three (2.64 net) Birley/Umbach horizontal wells which, including the fourth quarter of 2016 drilling costs, totalled an average of $3.7 million per gross well. The higher average total cost per well incurred on our most recent drilling program, compared to the previous program, resulted from each well, on average, having longer lateral lengths and additional completion stages.

Also included in our year to date capital expenditures is $4.7 million for the expansion of our Birley/Umbach facility to 50 mmcf/d. We budgeted $10 million net for the total cost of this expansion in our capital program. Two (1.63 net) of the four (3.63 net) most recently drilled, completed and equipped Birley/Umbach wells are currently on restricted production as our existing facility capacity is 25 mmcf/d of raw natural gas. On commissioning of this facility's expanded capacity to 50 mmcf/d (net 41.76 mmcf/d) expected during the fourth quarter of 2017, these restrictions will be released and the remaining two (2.00 net) standing wells are expected to be brought on-stream bringing our exit production to our 2017 revised guidance of 6,300 – 6,500 boe/d (see "Outlook").

Our D&P Assets increased by $2.8 million during the current reporting periods for a non-cash pipeline transfer from a customer (see "Deferred Customer Obligation Amortization").

Rationalization of Non-Core Properties

We consider our Birley/Umbach properties to be our core properties and all other properties to be non-core. As a result we may, from time to time, dispose of non-core properties so that we can focus on the development of Montney liquids-rich natural gas at Birley/Umbach. During the year to date, we completed the sale of certain non-core assets located at Knopcik/Pipestone and East Gold Creek areas of northwestern Alberta for combined net proceeds of $17.8 million after customary adjustments. These properties were mostly comprised of undeveloped lands but included land prospective for Montney oil and liquids-rich natural gas with estimated production of 100 boe/d (65% natural gas).

Decommissioning Obligations

At September 30, 2017, we had decommissioning obligations of $30.0 million (December 31, 2016 - $29.1 million). The increase in decommissioning obligations resulted from additions of $0.7 million as a result of our 2017 drilling program in addition to $0.5 million in accretion charges. Partially offsetting this increase was $0.3 million in expenditures.

As at September 30, 2017 and December 31, 2016, the estimated obligation includes assumptions in respect of actual costs to abandon wells and facilities or reclaim the property, the time frame in which such costs will be incurred, as well as annual inflation of

2.0%, in order to calculate the future obligation. At September 30, 2017, a risk-free interest rate of 2.34% was used in order to calculate the present value of the obligation.

Outstanding Share Data

Authorized:

- Unlimited number of common shares
- Unlimited number of first preferred shares

Details of our share capital, share options and share awards outstanding are as follows:

	September 30 2017	December 31 2016
Common shares outstanding	**217,114,601**	216,442,834
Share options	**10,475,714**	6,471,200
Restricted awards	**200,370**	349,241
Performance awards	**-**	381,790
Weighted average common shares		
- basic	**216,721,020**	215,860,123
- diluted	**217,143,539**	215,860,123

As at November 8, 2017, we had 217,114,601 common shares, 10,311,549 share options, 200,370 restricted awards and nil performance awards outstanding.

Off Balance Sheet Arrangements

We did not enter into any off balance sheet arrangements during the current reporting periods.

Outlook

We continue to execute on our $40 million 2017 capital program and remain excited about the growth it will provide. As we implement this capital program we will continue to closely monitor our balance sheet and commodity prices.

We have made great strides over the past 12 months to improve our cost structure, including completing the Craft Share Distribution and executing a new gas handling agreement in BC. On a per boe basis, for fourth quarter of 2017, our net production expense is expected to approximate $10/boe. As we begin to increase our production at Birley/Umbach, our cost structure and profitability should significantly improve.

We forecasted the McMahon Plant outages during the second quarter of 2017, resulting in us achieving production guidance for the quarter. However, the McMahon Plant turnaround unexpectedly continued in July. Additionally, high pipeline pressure and further third party restrictions caused restricted flow rates in our August production. As a result of this lower than expected production, in addition to historically low natural gas benchmark prices during the third quarter, we are issuing the following 2017 revised guidance:

($ millions, except boe/d)	Previous 2017 Guidance (1)	**2017 Revised Guidance (2)**
Average production (boe/d)	4,200 - 4,300	3,600 - 3,700
Exit production (boe/d) (3)	6,300 - 6,500	6,300 - 6,500
Capital expenditures (4)	$ 40	$ 40
Net surplus (debt) as at December 31, 2017	$ 2	$ (2.7)

(1) **Previous 2017 guidance assumptions: AECO natural gas price $2.64/mmbtu, Station 2 natural gas price $2.11/mmbtu and Chicago Alliance natural gas price $2.92/mmbtu.**
(2) **Revised 2017 guidance assumptions: AECO natural gas price $2.15/mmbtu, Station 2 natural gas price $1.79/mmbtu and Chicago Alliance natural gas price $2.59/mmbtu.**
(3) **Exit production may be negatively impacted should we choose to voluntarily shut-in production in the event of low commodity prices.**
(4) **Includes decommissioning obligation expenditures and capitalized general and administrative costs.**

We are currently assessing our 2018 capital program in order to remain prudent in how we deploy our capital. We anticipate releasing our 2018 capital budget around mid-January 2018.

Quarterly Information from Operations

Summarized information by quarter for the two years ended September 30, 2017, appears below:

	Sept. 30 2017	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016	Sept. 30 2016	Jun. 30 2016	Mar. 31 2016	Dec. 31 2015
Production Volumes								
Natural gas liquids (boe/d)	**405**	441	482	613	599	604	733	364
Natural gas (mcf/d)	**14,109**	19,065	18,022	21,548	28,972	22,776	25,215	15,851
Crude oil (bbl/d)	**19**	19	29	451	1,036	769	817	922
Average daily production (boe/d)	**2,776**	3,638	3,514	4,655	6,464	5,169	5,753	3,928
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 42.07**	$ 44.48	$ 51.39	$ 40.70	$ 10.67	$ 25.78	$ 27.65	$ 30.59
Average natural gas price ($/mcf)	**$ 1.20**	$ 2.77	$ 2.71	$ 3.31	$ 2.22	$ 1.35	$ 1.43	$ 2.09
Average oil price ($/bbl)	**$ 51.49**	$ 59.55	$ 60.32	$ 71.98	$ 57.31	$ 50.59	$ 35.41	$ 47.93
Operating Netback (1)								
Average commodity pricing ($/boe)	**$ 12.61**	$ 20.22	$ 21.42	$ 27.67	$ 20.14	$ 16.50	$ 14.82	$ 22.51
Royalty recovery (expense) ($/boe)	**$ 0.52**	$ (0.33)	$ 0.20	$ (2.84)	$ (0.77)	$ (0.44)	$ (0.99)	$ 2.39
Realized gain (loss) on derivative contracts ($/boe)	**$ 6.54**	$ 1.01	$ 1.38	$ (0.35)	$ 1.84	$ 0.14	$ -	$ 1.26
Net production expenses ($/boe) (1)	**$ (12.32)**	$ (11.82)	$ (11.27)	$ (11.88)	$ (12.61)	$ (14.75)	$ (15.12)	$ (14.17)
Operating Netback ($/boe) (1)	**$ 7.35**	$ 9.08	$ 11.73	$ 12.59	$ 8.60	$ 1.45	$ (1.29)	$ 11.99
Wells Drilled (net)								
Total natural gas wells drilled (net)	**-**	3.63	-	2.64	-	-	-	-
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties	**$ 3,351**	$ 6,583	$ 6,838	$ 10,631	$ 11,518	$ 7,550	$ 7,244	$ 9,000
Adjusted funds (outflow) from operations (1)	**$ 647**	$ 1,195	$ 2,036	$ 1,713	$ 1,894	$ (1,721)	$ (2,890)	$ 1,865
Per share - basic & diluted ($/share)	**$ -**	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ (0.01)	$ (0.01)	$ 0.01
Net (loss) income (2)	**$ (3,923)**	$ (2,253)	$ 10,422	$ 6,427	$ (35,905)	$ (12,520)	$ (12,775)	$ (5,303)
Per share - basic & diluted ($/share)	**$ (0.02)**	$ (0.01)	$ 0.05	$ 0.03	$ (0.17)	$ (0.06)	$ (0.06)	$ (0.02)
Capital expenditures	**$ 14,733**	$ 8,235	$ 8,823	$ 4,177	$ 661	$ 1,347	$ 3,026	$ 9,998
Net surplus (1)	**$ 3,616**	$ 18,294	$ 25,622	$ 15,138	$ 7,217	$ 6,207	$ 20,180	$ 29,614
Total assets	**$ 155,799**	$ 144,891	$ 148,665	$ 139,975	$ 274,674	$ 366,586	$ 299,623	$ 321,564
Common Shares (thousands)								
Weighted average during period - basic	**217,115**	216,598	216,443	216,443	216,287	215,350	215,349	215,337
Weighted average during period - diluted	**217,115**	216,598	216,900	216,621	216,287	215,350	215,349	215,337
Outstanding at period end	**217,115**	217,115	216,443	216,443	216,443	215,350	215,350	215,349

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

(2) Includes ($10.9 million) and $52.0 million in impairment (net reversal) charges against properties for the three months ended December 31, 2016 and September 30, 2016, respectively.

Factors That Have Caused Variations over the Quarters

The factors described below only apply to the quarterly information presented above.

Generally, the changes in operating results and their corresponding financial measures during the first three quarters of 2017, in comparison to prior quarters, result from the Subject Assets as either sold in October 2016 or as included in the Craft Share Distribution. Beginning in the first quarter of 2017 our operating and financial results reflect the completion of our transition to a pure play Montney company. Production results for 2017 trended upward as a result of production from our 2016 Birley/Umbach program which came on-stream late in the first quarter of 2017; however, third party plant turnarounds and other restrictions resulted in a decrease in production during the third quarter. The effect of the Subject Assets, resulting from the October 2016 disposition and Craft Share Distribution, resulted in lower reported volumes during the fourth quarter of 2016. For quarters prior thereto, generally, our shut-in of properties in response to lower commodity prices has resulted in a lower trend of natural gas and natural gas liquids production volumes. This trend was partially offset during the first quarter of 2016 when we brought on-stream an additional three (2.75 net) wells from a previous year's drilling program at Birley/Umbach on the commissioning of our new compression facility. Our crude oil production volumes generally trended down due to ongoing pipeline service restrictions and reduced system capacity. The acquisition of Craft and its associated volumes increased our production during the third quarter of 2016. Further increasing our third quarter of

2016 production volumes was higher commodity pricing combined with a more favorable gas handling contract that allowed the reactivation of previously shut-in wells.

Our realized commodity prices and petroleum and natural gas revenue, net of royalties mostly trended with the Canadian Light Sweet and AECO benchmarks which decreased during the end of 2015 and the beginning of 2016, with the Canadian Light Sweet benchmark not beginning to recover until the second quarter of 2016 while the AECO benchmark recovered in the third quarter of 2016. However, beginning in the first quarter of 2017, subsequent to our transition to a Montney focus natural gas company, our realized commodity prices began trending with the Station 2 benchmark pricing. Changes in our petroleum and natural gas revenues, net of royalties and adjusted funds from operations have generally trended with benchmark commodity prices and volumes. Our net surplus has generally trended down as our capital expenditures exceeded our adjusted funds from operations. It further decreased in the second quarter of 2016 when we acquired debt in connection with the Craft acquisition until December 12, 2016, when we completed the Craft Share Distribution. It increased again in the first quarter of 2017 as a result of proceeds received from non-core asset distributions. Our capital preservation efforts resulted in no drilling activity until the fourth quarter of 2016 when we drilled three (2.64 net) wells at Birley/Umbach, which were completed in the first quarter of 2017 followed by the drilling of an additional four (3.63 net) wells during the second quarter which were completed in the third quarter of 2017. Our non-core asset dispositions combined with adjusted funds from operations relative to capital expenditures have allowed us to avoid having to raise proceeds through the issuance of our common shares.

Please refer to other sections of this MD&A for detailed discussions on variations during the comparative quarters and to our previously issued interim and annual management’s discussion and analysis for changes in prior quarters.

Risk Factors

Investors should carefully consider the risk factors set out in our AIF and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of the these risks or other risks occur, our business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.

Additional information on risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements".

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting (“ICOFR”) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in our ICOFR were identified during the period beginning on July 1, 2017 and ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect our ICOFR.

We have designed our ICOFR based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

It should be noted that a control system, including our disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Other Information

Non-GAAP Measures

The following non-GAAP measures do not have any standardized meanings as prescribed by IFRS and, therefore, may not be comparable with the calculations of similar measures presented by other companies.

- Adjusted funds (outflow) from operations is calculated from cash flow from operations adjusted for changes in non-cash operating working capital, exploration and evaluation expenses, provision expenditures and severance/transaction costs. We believe that adjusted funds (outflow) from operations is a key measure to assess our ability to finance capital expenditures and when debt is drawn, to finance debt repayments. Adjusted funds (outflow) from operations is not intended to represent cash flow from operating activities, net income (loss) or other measures of financial performance calculated in accordance with IFRS and should not be construed as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS as an indicator of our financial performance. Adjustments to cash flow from operations are for changes in non-cash operating working capital which are expected to reverse and for those costs that are not directly caused by lifting production volumes.

- Net surplus (debt) is calculated as bank debt adjusted for current assets less current liabilities as they appear on the balance sheets, both of which exclude mark-to-market commodity price contracts and assets and liabilities held for sale and current liabilities excludes any current portion of debt, deferred customer obligations and provisions. We use net surplus (debt) to assist us in understanding our liquidity at specific points in time. We exclude the current portion of provisions and the deferred customer obligation as they are not financial instruments. Mark-to-market commodity contracts and assets and liabilities held for sale are excluded as they are unrealized.

- Operating netback is calculated as a period’s sales of petroleum and natural gas, net of realized gains or losses on commodity price contracts, royalties and net production expenses, divided by the period’s sales volumes. We use this non-GAAP measure to assist us in understanding our production profitability relative to current and fixed commodity prices and it provides an analytical tool to benchmark changes in field operational performance against prior periods. Readers are cautioned, however, that this measure should not be construed as an alternative to other terms such as net income determined in accordance with IFRS as a measure of performance.

- Net production expense is calculated as production and operating expense less processing and gathering revenues. We use net production expense to determine the current periods’ cash cost of operating expenses and net production expense per boe is used to measure operating efficiency on a comparative basis.

Forward-Looking Statements

In the interest of providing our shareholders and readers with information regarding our company, including management's assessment of our future plans and operations, certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "potential", "target" and similar words suggesting future events or future performance. In particular, this MD&A contains, without limitation, forward-looking statements pertaining to: the expected timing of our Birley/Umbach facility capacity expansion to 50 mmcf/d and the consequent release of the flow restrictions and on-stream timing of our four most recent Birley/Umbach wells, expectations regarding crown royalties and the receipt of additional credits in 2017, the expected decrease in our production costs under $10/boe once production volumes from our most recent 2017 four well drilling campaign are brought on-stream at full capacity and subject to our ability to maintain our production volumes, our expectation that the new gas handling agreement will significantly improve our go-forward drilling economics and reduce our operating costs, the amount and composition of our 2017 capital program and how we intend to fund the program, our anticipated 2017 G&A expense, future exploration and development activities and the timing thereof and how we intend to manage our company, our revised guidance regarding average and ending production for 2017, capital expenditures for 2017 and net surplus (debt) at December 31, 2017 set forth under the heading “Outlook” as well as when we anticipate releasing our 2018 capital budget. 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.

With respect to the forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: that we will continue to conduct our operations in a manner consistent with that expressed herein, future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, future currency, exchange and interest rates, our ability to obtain equipment in a timely manner to carry out exploration and development activities, the ability of the operator of the projects in which we have an interest in to operate in the field in a safe, efficient and effective manner, the impact of increasing competition, field production rates and decline rates, anticipated production volumes, our ability to replace and expand production and reserves through exploration and development activities, certain cost assumptions, that the budgeted 2017 capital program, which is subject to the discretion of our Board of Directors, will not be amended in the future, and the continued availability of adequate debt and cash flow to fund our planned expenditures. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, our Board of Directors may amend the 2017 capital program based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increases in or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Future Oriented Financial Information

This MD&A, in particular the information in respect of our forecast nominal crown royalties in 2017, net production expense per boe, G&A per boe, anticipated capital expenditures in 2017 and our guidance in respect of our net surplus (debt) at December 31, 2017, may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by our management to provide an outlook of our activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward-Looking Statements" and assumptions with respect to production rates and commodity prices. The actual results of our operations and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. Our management believes that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.

Selected Definitions and Abbreviations

Oil and Natural Gas Liquids

bbl	barrels
bbl/d	barrels per day
NGLs	natural gas liquids

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
GJ	gigajoules
GJ/d	gigajoules per day

Other

boe	barrel of oil equivalent on the basis of 6 mcf/1 boe for natural gas and 1 bbl/1 boe for crude oil and natural gas liquids (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
mboe	1,000 barrels of oil equivalent
Canadian Light Sweet	Central market point for Canadian crude oil
BC Westcoast Station 2	Market point for BC natural gas
AECO	Central market point for Canadian natural gas

Barrels of Oil Equivalent

Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.