Q2 2017

Management's Discussion and Analysis

CHINOOK energy inc

Chinook Energy Inc. | 1000, 517 – 10th Avenue S.W. Calgary, Alberta T2R 0A8 TSX:CKE

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 six months ended June 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 six months ended June 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 (the "Annual Financial Statements"). This MD&A is based on information available as at August 10, 2017.

The term "second quarter" or "year to date" or similar terms are used throughout this document and refer to the three or six months ended June 30, 2017, respectively. The term "current reporting periods" or similar terms are used throughout this document and refer to both the three and six months ended June 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) six months ended June 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 as either sold in October 2016 or as included in the Craft Share Distribution. During the comparative periods we also recognized a deferred income tax expense as an indirect tax consequence of the Craft acquisition in addition to a recovery for the loss attributable to Craft’s non-controlling interest.

Financial and Operating Highlights

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
OPERATIONS				
Production (1)				
Natural gas liquids (boe/d)	**441**	604	**461**	669
Natural gas (mcf/d)	**19,065**	22,776	**18,546**	23,995
Crude oil (bbl/d)	**19**	769	**24**	793
Average daily production (boe/d)	**3,638**	5,169	**3,576**	5,461
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 44.48**	$ 25.78	**$ 48.07**	$ 26.81
Average natural gas price ($/mcf)	**$ 2.77**	$ 1.35	**$ 2.74**	$ 1.39
Average oil price ($/bbl)	**$ 59.55**	$ 50.59	**$ 60.01**	$ 42.76
Netback (2)				
Average commodity pricing ($/boe)	**$ 20.22**	$ 16.50	**$ 20.81**	$ 15.61
Royalties ($/boe)	**$ (0.33)**	$ (0.44)	**$ (0.07)**	$ (0.73)
Realized gains on derivative contracts ($/boe)	**$ 1.01**	$ 0.14	**$ 1.19**	$ 0.08
Net production expenses ($/boe) (2)	**$ (11.82)**	$ (14.75)	**$ (11.55)**	$ (14.95)
Operating Netback ($/boe) (2)	**$ 9.08**	$ 1.45	**$ 10.38**	$ 0.01
Wells Drilled (net)				
Total natural gas wells drilled (net)	**3.63**	-	**3.63**	-
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 6,583**	$ 7,550	**$ 13,421**	$ 14,794
Adjusted funds (outflow) from operations (2)	**$ 1,195**	$ (1,721)	**$ 3,231**	$ (4,611)
Per share - basic & diluted ($/share)	**$ 0.01**	$ (0.01)	**$ 0.01**	$ (0.02)
Net (loss) income	**$ (2,253)**	$ (12,520)	**$ 8,169**	$ (25,295)
Per share - basic and diluted ($/share)	**$ (0.01)**	$ (0.06)	**$ 0.04**	$ (0.12)
Capital expenditures	**$ 8,235**	$ 1,347	**$ 17,058**	$ 4,373
Net surplus (2)	**$ 18,294**	$ 6,207	**$ 18,294**	$ 6,207
Total assets	**$ 144,891**	$ 366,586	**$ 144,891**	$ 366,586
Common Shares (thousands)				
Weighted average during period				
- basic	**216,598**	215,350	**216,521**	215,350
- diluted	**216,598**	215,350	**217,042**	215,350
Outstanding at period end	**217,115**	215,350	**217,115**	215,350

(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 June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Natural gas liquids (boe/d)	**441**	604	**461**	669
Natural gas (mcf/d)	**19,065**	22,776	**18,546**	23,995
Crude oil (bbl/d)	**19**	769	**24**	793
Total (boe/d)	**3,638**	5,169	**3,576**	5,461

Total Production Volumes

During the current reporting periods, our production decreased by 1,531 boe/d and 1,885 boe/d compared to the same periods of 2016. An earlier and longer than scheduled Enbridge McMahon gas plant (“McMahon Plant”) restriction caused by their turnaround resulted in June’s production being 4,300 boe/d lower than May. As our operations are now focussed in northeastern BC, there was an increase during the current reporting periods in the weighted average production volume ratios flowing to the McMahon Plant, compared to the same periods in 2016. With these increased ratios, the effect of the McMahon Plant restriction was more significant to our current periods’ reported production volumes. 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 have since been impacted by further McMahon Plant restrictions. 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 third party downstream sales pipelines provides us with optionality upon the future development of a gas plant, to flow directly to the Alliance pipeline with access to Chicago markets, 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 from these and other previously drilled wells in that area resulted in lower production volumes of 360 boe/d and 485 boe/d compared to the same periods of 2016. Also contributing to the decreases in volumes were the Subject Assets that, last year, were either sold or included in the Craft Share Distribution. In 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 decreases, during the current reporting periods, but excluding days the wells were not on-stream, we added 1,450 boe/d and 1,350 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. Currently, we have production from nine wells (7.63 net) in this area. As a result of the production from these new wells we had an increase in our Birley/Umbach area production volumes for the current reporting periods in comparison to the same periods of 2016. Further contributing to the current reporting periods’ production volumes were reactivations of our Martin Creek and Black Conroy fields 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 commodity price improvements and a new natural gas handling agreement. We produced an additional 1,400 boe/d and 1,100 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 we were refunded our $3.0 million Liability Management Ratio deposit from the BC Oil & Gas Commission.

During the second quarter, at our Birley/Umbach area, we drilled another four (3.63 net) wells. All four wells were drilled on our D-93-F pad with various downhole locations. All four of these Birley/Umbach wells are scheduled to be on-stream during the fourth quarter of 2017 bringing our exit production to our guidance of 6,300 - 6,500 boe/d.

To date, our operated field operations have not directly been affected by the current wildfires in BC; however, there has been some effect on the downstream non-operated infrastructure. We will continue to monitor this situation.

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 restriction due to a turnaround in June which halted the majority of our BC production and the absence of the Subject Assets. Partially offsetting this decrease was higher production from our Birley/Umbach area development program and the reactivation of wells in Martin Creek, Black Conroy and Boundary Lake North, BC.

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 June 30		Six months ended June 30	
($ thousands, except per unit amounts)	**2017**	2016	**2017**	2016
Natural gas liquids sales	**$ 1,786**	$ 1,417	**$ 4,014**	$ 3,263
$/boe	**44.48**	25.78	**48.07**	26.81
Natural gas sales	**$ 4,805**	$ 2,803	**$ 9,196**	$ 6,085
$/mcf	**2.77**	1.35	**2.74**	1.39
Oil sales	**$ 103**	$ 3,538	**$ 259**	$ 6,171
$/bbl	**59.55**	50.59	**60.01**	42.76
Petroleum & natural gas revenue	**$ 6,694**	$ 7,758	**$ 13,469**	$ 15,519
$/boe	**20.22**	16.50	**20.81**	15.61

Our petroleum and natural gas revenues decreased for the current reporting periods compared to the same periods of 2016. These decreases were due to lower production volumes despite significantly higher benchmark pricing. The lower production volumes were because of a longer than scheduled McMahon Plant restriction in June and the absence of the Subject Assets. This decrease was partially offset by the reactivation of previously shut-in wells and added production from our 2016 Birley/Umbach area drilling programs. The increase in our realized commodity pricing for the current reporting periods was due to higher benchmark pricing. Our increased realized commodity prices were partially offset by the effect of a higher ratio of natural gas relative to total production volumes that occurred through our transition to a pure Montney play. This is because natural gas, on a heating equivalent basis, receives a lower price.

Benchmark Prices

	Three months ended June 30		Six months ended June 30	
	2017	2016	**2017**	2016
Natural gas liquids				
Canadian light sweet [1] ($/bbl)	**$ 59.72**	$ 55.01	**$ 62.27**	$ 48.11
Natural gas				
AECO gas [2] ($/mcf)	**$ 2.79**	$ 1.42	**$ 2.74**	$ 1.62
BC Westcoast Station 2 [3] ($/mcf)	**$ 2.43**	$ 1.21	**$ 2.45**	$ 1.31

(1) Central market point for Canadian crude oil.
(2) Central market point for Canadian natural gas.
(3) Market point for BC natural gas.

NGL Pricing

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. The comparative periods' realized NGL prices were affected by an adjustment that decreased that periods' NGL revenues. Excluding this effect, the comparative periods' NGL realized prices were approximately $40/boe and $34/boe. During the current reporting periods, consistent with the increase in the Canadian light sweet oil benchmark, our realized NGL prices of $44.48/boe and $48.07/boe increased compared to the same periods of 2016 after excluding the NGL revenue adjustment.

The ratio of our NGL price relative to Canadian light sweet oil was 74% and 77% for the current reporting periods which increased compared to approximately 71% for the same periods of 2016 after excluding the NGL revenue adjustment. 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. During 2016, we transformed into a pure Montney play focused on liquids-rich natural gas in our Birley/Umbach area upon completion of the Craft Share Distribution.

Natural Gas Pricing

Our realized natural gas prices of $2.77/mcf and $2.74/mcf during the current reporting periods significantly increased compared to $1.35/mcf and $1.39/mcf for the same periods of 2016. These increases were consistent with higher AECO and Station 2 benchmark pricing. Our current reporting periods realized natural gas prices also reflects an $0.18/GJ and $0.21/GJ premium in the Alliance Chicago benchmark price relative to the Station 2 benchmark price. During the current reporting periods, we sold approximately 17% and 22% of our natural gas production at an average Alliance Chicago price of $2.38/GJ.

During June, in comparison to May, the AECO natural gas benchmark price decreased by $0.40/GJ. This decrease had a minimal impact on our realized pricing as the majority of our BC production was shut-in as a result of the scheduled McMahon Plant turnaround. AECO and Station 2 benchmark pricing volatility continued during July due to high line pack resulting from the McMahon Plant turnaround and subsequent restrictions in addition to downstream sales pipeline maintenance.

Royalties

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Royalties	**$ 111**	$ 208	**$ 48**	$ 725
Per sales ($/boe)	**$ 0.33**	$ 0.44	**$ 0.07**	$ 0.73
Percent of revenues (%)	**2**	3	**-**	5

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 which are located throughout Alberta with higher royalty rates associated with crude oil volumes. 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 $0.3 million and $0.5 million of this credit through a decrease to our royalties during the current reporting periods. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program where we currently have $3.7 million in remaining royalty credits. The eight Birley/Umbach wells that have qualified for this credit program bear a minimum crown royalty rate of 3% prior to applying the BC Infrastructure Royalty Credits. We further anticipate receiving additional royalty credits during 2017 from the Infrastructure Program for our three most recently drilled and completed Birley/Umbach wells that were brought on-stream in mid-March with possible further grants should our 2017 four well drilling campaign be successful. During 2017 we are forecasting nominal 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. We continuously review the need to utilize such financing strategies.

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 reported periods and the same periods of 2016, we reported the following realized and unrealized gains and losses from our commodity price contracts:

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Realized gain on commodity price contracts	**$ (333)**	$ (68)	**$ (769)**	$ (68)
Unrealized (gain) loss on commodity price contracts	**(300)**	3,576	**(1,587)**	3,576
Total	**$ (633)**	$ 3,508	**$ (2,356)**	$ 3,508
Realized gain on commodity price contracts ($/boe)	**$ 1.01**	$ 0.14	**$ 1.19**	$ 0.08

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 $2.97/mcf compared to our reported prices of $2.77/mcf and $2.74/mcf. On a per boe basis, the realized gains on our commodity price contracts were exaggerated during the current reporting periods as they are paid on notional volumes but are calculated using physical volumes.

Our unrealized gains for the current reporting periods include the decrease in the forward AECO price relative to the fixed contracted prices. As at June 30, 2017, our commodity price contracts had a combined estimated current asset fair value of $1.4 million with the following terms:

Indexed Price	Notional Volumes	Company's Received Price	Remaining Contractual Term
AECO	7,500 GJ/d	$3.205/GJ	July 1, 2017 to December 31, 2017
AECO	4,000 GJ/d	$2.50/GJ	July 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 42% of our forecasted 2017 natural gas production volumes.

At June 30, 2017, because we had no outstanding debt and were in a net surplus position of $18.3 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% of our forecasted twelve month combined production volumes.

Production and Operating Expense

	Three months ended		Six months ended	
		June 30		June 30
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Production & operating	**$ 4,122**	$ 7,534	**$ 7,946**	$ 16,312
Less:				
Processing & gathering revenues	**(208)**	(597)	**(468)**	(1,457)
Net production & operating expense [(1)]	**$ 3,914**	$ 6,937	**$ 7,478**	$ 14,855
Per sales net production & operating expenses ($/boe) [(1)]	**$ 11.82**	$ 14.75	**$ 11.55**	$ 14.95
Per sales production & operating expenses ($/boe)	**$ 12.45**	$ 16.02	**$ 12.28**	$ 16.41

(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, which on a boe basis had relatively higher operating costs. Although we increased our 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 which we executed late during the third quarter of 2016 and which impacts the majority of our BC natural gas production. It 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 further expect our on-going operations to incur production costs under $10/boe once production volumes from our 2017 four well drilling campaign are brought on-stream. However, the current reporting periods' operating costs on a per boe basis were higher than our expectations. During the second quarter, our fluid hauling costs more than doubled. This was necessitated by road bans resulting from wet weather conditions causing partial truck loads and higher than forecast water production and hauling costs caused by the three (2.64 net) most recently drilled and completed Birley/Umbach wells. 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 operating costs on a boe basis compared to our expectations. Finally, we incurred seasonal costs including the repair and maintenance of our processing plants and on 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 because of the processing and gathering assets included within the Subject Assets that, last year, were either sold or included in the Craft Share Distribution.

Operating Netback

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

	Three months ended June 30		Six months ended June 30	
Per sales ($/boe)	**2017**	2016	**2017**	2016
Realized sales price	**$ 20.22**	$ 16.50	**$ 20.81**	$ 15.61
Royalties	**(0.33)**	(0.44)	**(0.07)**	(0.73)
Realized gain on commodity price contract	**1.01**	0.14	**1.19**	0.08
Net production expense [(1)]	**(11.82)**	(14.75)	**(11.55)**	(14.95)
Operating netback [(1)]	**$ 9.08**	$ 1.45	**$ 10.38**	$ 0.01

(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 significantly increased for the current reporting periods compared to the same periods of 2016. These increases resulted from higher commodity pricing combined with realized gains on our commodity price contracts. As already discussed, our June production was impacted due to an earlier and longer than scheduled McMahon Plant turnaround. Our transition to a pure Montney play resulted in a lower net production expense and BC Government grants decreased our royalties. These changes have been previously discussed.

General & Administrative ("G&A") Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
G&A expense before recoveries	**$ 2,265**	$ 3,312	**$ 4,755**	$ 6,749
Recoveries	**(730)**	(1,245)	**(1,608)**	(2,792)
G&A expense	**$ 1,535**	$ 2,067	**$ 3,147**	$ 3,957
Per sales ($/boe)	**$ 4.64**	$ 4.40	**$ 4.86**	$ 3.98

We have focused 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. As a result of lower staffing costs due to reductions in headcount, reduced information system costs and less reliance on consultants and professional services, our overall G&A expense during the current reporting periods decreased compared to the same periods of 2016. We also realized savings for the entire current reporting periods of previously reported cost cuts including reduced compensation for officers and directors in addition to reduced employee benefits. As a result of these efforts, G&A before recoveries decreased $1.0 million and $2.0 million during the current reporting periods compared to the same periods of 2016. However, partially offsetting these decreases were lower G&A recoveries. With both lower compensation and operating costs combined with a shift to more focussed operated properties, our capitalized G&A, operating and other associated G&A recoveries decreased by $0.5 million and $1.2 million during the current reporting periods compared to the same periods of 2016. During the current reporting periods, 25% of our G&A expense before recoveries resulted from head office rent charges pursuant to a lease which expires June 30, 2019. Assuming current rental market conditions remain the same or similar, we anticipate paying lower rent commencing in 2019 upon our lease expiration, assuming the same existing office space requirements.

Despite a decrease in our overall G&A expense, G&A on a boe basis increased during the current reporting periods as a result of the previously discussed production decreases. We anticipate that our G&A expense will be approximately $4.00/boe for the full 2017 year.

Transaction and Severance Costs

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2017**	2016	**2017**	2016
Transaction & severance costs	**$ 135**	$ 1,620	**$ 508**	$ 1,620

Severance costs incurred in the current reporting periods related to staffing reductions resulting from both a continuing assessment of our staffing requirements and the simplification of our current operations. During the comparative periods of 2016, transaction costs related to costs incurred on the Subject Asset conveyance to Craft.

Exploration and Evaluation Expense

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2017**	2016	**2017**	2016
Exploration & evaluation expenditures	**$ 103**	$ 321	**$ 195**	$ 817

Exploration and evaluation expense reported during the current reporting periods were due to 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 the Subject Assets that, last year, were either sold or included in the Craft Share Distribution.

Depletion, Depreciation and Amortization (“DD&A”) Expense

	Three months ended June 30		Six months ended June 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Depletion, depreciation & amortization	**$ 3,074**	$ 6,642	**$ 6,007**	$ 13,788
Depletion per sales ($/boe)	**$ 7.93**	$ 12.13	**$ 7.89**	$ 11.98

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 the Subject Assets that, last year, were either sold or included in the Craft Share Distribution. The decreased depletion rates were also caused by an increase in the December 31, 2016 measure of our on-going operations' proved plus probable reserves. Amortization expense during the current reporting periods decreased $0.5 million and $1.0 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 June 30		Six months ended June 30	
($ thousands)	**2017**	2016	**2017**	2016
Gain on dispositions of properties	**$ -**	$ (6,714)	**$ (10,926)**	$ (5,859)

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 $7.9 million.

Share-Based Compensation

($ thousands)	Three months ended June 30 2017	2016	Six months ended June 30 2017	2016
Share-based compensation	**$ 258**	$ 672	**$ 509**	$ 1,352

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.

Other Losses

($ thousands)	Three months ended June 30 2017	2016	Six months ended June 30 2017	2016
Other losses	**$ 321**	$ 212	**$ 476**	$ 602

During the current reporting periods and the same periods of 2016, we incurred a fee for a take or pay processing agreement in respect of which we did not deliver the required liquids because economic conditions in addition to our prior year strategic alternatives review caused the delay of the necessary infrastructure development. 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

($ thousands)	Three months ended June 30 2017	2016	Six months ended June 30 2017	2016
Interest & financing (income) charges	**$ (40)**	$ 99	**$ (124)**	$ 112
Accretion of decommissioning obligation	**169**	578	**338**	1,130
Total	**$ 129**	$ 677	**$ 214**	$ 1,242

We reported interest & financing income of $0.1 million during the year to date as our interest earned from cash on hand was greater than fees we paid on our new $8 million demand credit facility. During the comparative period, interest & financing charges were $0.1 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

($ thousands, except where noted)	Three months ended June 30 2017	2016	Six months ended June 30 2017	2016
Weighted average shares outstanding - basic (thousands)	**216,598**	215,350	**216,521**	215,350
Dilutive impact of share based awards (thousands)	**-**	-	**521**	-
Weighted average shares outstanding - diluted (thousands)	**216,598**	215,350	**217,042**	215,350
Net & comprehensive (loss) income	**$ (2,253)**	$ (12,520)	**$ 8,169**	$ (25,295)
Per share - basic & diluted ($/share)	**$ (0.01)**	$ (0.06)	**$ 0.04**	$ (0.12)

For the second quarter we are reporting a decrease in net loss, whereas for the year to date we are reporting an increase in net income compared the same periods of 2016. For the year to date, a $10.9 million gain on the disposition of non-core properties increased net income. These favorable changes for the current reporting periods also reflect higher commodity prices, a lower cost structure associated with our transition to a pure Montney play in addition to $0.6 million and $2.4 million gains on commodity price contracts.

The comparative periods also include a net loss from the Craft operations, including both a $3.6 million loss on commodity price contracts and a $7.1 million deferred income tax expense but as partially offset by a $3.4 million non-controlling interest recovery.

Capital Resources, Capital Expenditures and Liquidity

Since the beginning of the economic downturn during 2014 we have focused on capital preservation and optionality while continuing to focus our operation through non-core asset dispositions. During 2016, we completed the transition to a pure Montney play 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. With our net surplus of $18.3 million at June 30, 2017 combined with our expected adjusted funds from operations during the second half of 2017, we have the necessary financing to fund the remainder of our 2017 capital program.

During the year to date, we executed an $8.0 million demand credit facility with a Canadian chartered bank. During the quarter, the previous limitations on our borrowings under this credit facility were removed upon the confirmation that the three Birley/Umbach wells completed and brought on-stream during the first quarter of 2017 are producing to the lender's satisfaction. Although we do not anticipate drawing on this facility during 2017, funds availability from this facility provides us with further financial flexibility.

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 June 30		Six months ended June 30	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Cash flow (outflow) from operating activities	**$ 6,280**	$ (1,630)	**$ 4,835**	$ (5,965)
Add back (deduct):				
Change in operating non-cash working capital	**(5,364)**	(2,543)	**(2,441)**	(4,759)
Decommissioning obligation expenditures	**41**	511	**134**	3,676
Exploration & evaluation expenses	**103**	321	**195**	817
Transaction & severance costs	**135**	1,620	**508**	1,620
Adjusted funds (outflow) from operations (1)	**$ 1,195**	$ (1,721)	**$ 3,231**	$ (4,611)
Per share - basic & diluted	**$ 0.01**	$ (0.01)	**$ 0.01**	$ (0.02)

(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.

During the current reporting periods, we are reporting increases in adjusted funds from operations of $1.2 million and $3.2 million, compared to adjusted funds outflows of $1.7 million and $4.6 million in the same periods of 2016. These increases resulted from higher commodity benchmark prices and a lower cash-based cost structure for our Montney focused operations. The decreases in the current reporting periods cash-based costs is also because of the Subject Assets with its higher associated cost structure that, last year, were either sold or included in the Craft Share Distribution. We also had $0.3 million and $0.8 million realized gains from commodity price contracts during the current reporting periods.

Our second quarter adjusted funds from operations is the fourth consecutive quarter we have reported positive adjusted funds flow which corresponds to when we started our transition to a pure Montney play.

Credit Facilities

	June 30 2017	December 31 2016
($ thousands)		
Long-term debt	**$ -**	$ -
Less:		
Accounts payable, accrued liabilities & other	**(6,909)**	(11,218)
Add:		
Cash and restricted cash	**19,977**	16,129
Accounts receivable	**3,286**	6,658
Prepaids & deposits	**1,940**	3,569
Net surplus (1)	**$ 18,294**	$ 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 $18.3 million at June 30, 2017 compared to $15.1 million at December 31, 2016. This increase of $3.2 million was caused by disposition proceeds of $17.8 million and adjusted funds from operations net of capital, decommissioning, exploration and evaluation expenditures and severance costs.

During the year to date, our previous credit facility agreement was terminated and we negotiated and secured an $8.0 million demand credit facility (the "Demand Credit Facility") with a Canadian chartered bank. At any time, the lender can request repayment of all outstanding drawn amounts resulting in any future borrowings being classified as a current liability. The Demand Credit Facility's availability is subject to semi-annual reviews with the next review scheduled on or before November 1, 2017. Changes in the availability in the Demand Credit Facility are possible, from one 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. As at June 30, 2017, we 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 reduced our available credit to $7.2 million.

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. In addition, the Demand Credit Facility includes operating and financial restrictions on us that include restrictions on paying dividends or repurchasing or making of other distributions with respect to our securities.

As at the end of any fiscal quarter, if we have any net debt or Demand Credit Facility draws, within 60 days of the end of any such quarter, the terms of the Demand Credit Facility also require that we must enter into commodity price contracts covering no less than 30% of our forecasted twelve month combined production volumes.

As at June 30, 2017, we are 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 current reporting periods, the lender released its restrictions to this cash pursuant to the increase to $8.0 million of the Demand Credit Facility availability.

Capital Expenditures

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

	Three months ended June 30		Six months ended June 30	
($ thousands)	**2017**	2016	**2017**	2016
Land & lease	**$ -**	$ 118	**$ -**	$ 147
Drilling & completions	**5,385**	-	**12,561**	-
Facilities & equipment	**2,660**	932	**4,075**	3,610
Field expenditures	**8,045**	1,050	**16,636**	3,757
Capitalized G&A	**190**	297	**422**	616
Total	**$ 8,235**	$ 1,347	**$ 17,058**	$ 4,373
Proceeds from dispositions	**$ -**	$ 7,613	**$ 17,838**	$ 7,912

During the second quarter, we drilled four (3.63 net) horizontal Montney gas wells with various downhole locations on our Birley/Umbach property in northeastern BC on our D-93-F pad. Two of the wells have approximately 1,800 metre horizontal lateral sections. Drilling costs of these wells were consistent with our guidance despite road restrictions that delayed operations and increasing transportation costs. Completions and equipping are scheduled for the third quarter of 2017. All four wells will use 55 tonne fracs at 52 metre spacing and are scheduled to be on-stream during the fourth quarter of 2017 bringing our exit production to our guidance of 6,300 - 6,500 boe/d.

Our year to date capital expenditures include the costs to complete, equip and tie-in three (2.64 net) horizontal wells at Birley/Umbach which, including the fourth quarter of 2016 drilling costs, totalled an average of $3.7 million per well, a 30% decrease from the previous six (5.0 net) wells which averaged $5.3 million per well. All of these wells were drilled with a lateral section of approximately 1,450 metres with a 24 stage completion at 65 tonnes per stage. Our year to date capital expenditures also include $2.3 million for the expansion of our Birley/Umbach facility to 50 mmcf/d. We budgeted $10 million for the total cost of this expansion in our capital program.

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 June 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 $0.3 million in accretion charges. Partially offsetting this increase was $0.1 million in expenditures.

As at June 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 June 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:

	June 30 2017	December 31 2016
Common shares outstanding	**217,114,601**	216,442,834
Share options	**11,002,928**	6,471,200
Restricted awards	**237,958**	349,241
Performance awards	**-**	381,790
Weighted average common shares		
- basic	**216,520,968**	215,860,123
- diluted	**217,042,326**	215,860,123

As at August 9, 2017, we had 217,114,601 common shares, 10,873,216 share options, 237,958 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 previously announced $40 million capital program for 2017 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. As in previous years, we will remain prudent in how we deploy our capital in order to defend our strong balance sheet.

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 $8.00/boe. As we begin to increase our production at Birley/Umbach, our cost structure and profitability significantly improve.

We forecasted the McMahon Plant outages during the second quarter of 2017, resulting in us achieving production guidance for the quarter. However, this McMahon Plant turnaround continued past our expectations in July. Additionally, we have been experiencing some Enbridge downstream line issues and TCPL maintenance issues upstream of James River that may negatively impact our Birley/Umbach production volumes and/or field prices during the latter part of August. We are evaluating the impact of these unbudgeted proposed production outages and their impact on field prices. However, for the interim, we are maintaining our previously announced production guidance for 2017 as follows:

($ millions, except boe/d)		2017 Guidance (1)
Average production (boe/d)		4,200 - 4,300
Exit production (boe/d)		6,300 - 6,500
Capital expenditures (2)	$	40
Net surplus as at December 31, 2017	$	2

(1) 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) Includes decommissioning obligation expenditures and capitalized general and administrative costs.

Quarterly Information from Operations

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

	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016	Sept. 30 2016	Jun. 30 2016	Mar. 31 2016	Dec. 31 2015	Sept. 30 2015
Production Volumes								
Natural gas liquids (boe/d)	**441**	482	613	599	604	733	364	395
Natural gas (mcf/d)	**19,065**	18,022	21,548	28,972	22,776	25,215	15,851	20,641
Crude oil (bbl/d)	**19**	29	451	1,036	769	817	922	1,065
Average daily production (boe/d)	**3,638**	3,514	4,655	6,464	5,169	5,753	3,928	4,900
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 44.48**	$ 51.39	$ 40.70	$ 10.67	$ 25.78	$ 27.65	$ 30.59	$ 31.68
Average natural gas price ($/mcf)	**$ 2.77**	$ 2.71	$ 3.31	$ 2.22	$ 1.35	$ 1.43	$ 2.09	$ 2.56
Average oil price ($/bbl)	**$ 59.55**	$ 60.32	$ 71.98	$ 57.31	$ 50.59	$ 35.41	$ 47.93	$ 51.34
Operating Netback (1)								
Average commodity pricing ($/boe)	**$ 20.22**	$ 21.42	$ 27.67	$ 20.14	$ 16.50	$ 14.82	$ 22.51	$ 24.48
Royalties ($/boe)	**$ (0.33)**	$ 0.20	$ (2.84)	$ (0.77)	$ (0.44)	$ (0.99)	$ 2.39	$ (1.13)
Realized gains (losses) on derivative contracts ($/boe)	**$ 1.01**	$ 1.38	$ (0.35)	$ 1.84	$ 0.14	$ -	$ 1.26	$ 0.87
Net production expenses ($/boe) (1)	**$ (11.82)**	$ (11.27)	$ (11.88)	$ (12.61)	$ (14.75)	$ (15.12)	$ (14.17)	$ (12.49)
Operating Netback ($/boe) (1)	**$ 9.08**	$ 11.73	$ 12.59	$ 8.60	$ 1.45	$ (1.29)	$ 11.99	$ 11.72
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	**$ 6,583**	$ 6,838	$ 10,631	$ 11,518	$ 7,550	$ 7,244	$ 9,000	$ 10,527
Adjusted funds (outflow) from operations (1)	**$ 1,195**	$ 2,036	$ 1,713	$ 1,894	$ (1,721)	$ (2,890)	$ 1,865	$ 3,299
Per share - basic & diluted ($/share)	**$ 0.01**	$ 0.01	$ 0.01	$ 0.01	$ (0.01)	$ (0.01)	$ 0.01	$ 0.02
Net (loss) income (2)	**$ (2,253)**	$ 10,422	$ 6,427	$ (35,905)	$ (12,520)	$ (12,775)	$ (5,303)	$ (80,669)
Per share - basic & diluted ($/share)	**$ (0.01)**	$ 0.05	$ 0.03	$ (0.17)	$ (0.06)	$ (0.06)	$ (0.02)	$ (0.37)
Capital expenditures	**$ 8,235**	$ 8,823	$ 4,177	$ 661	$ 1,347	$ 3,026	$ 9,998	$ 7,313
Net surplus (1)	**$ 18,294**	$ 25,622	$ 15,138	$ 7,217	$ 6,207	$ 20,180	$ 29,614	$ 41,181
Total assets	**$ 144,891**	$ 148,665	$ 139,975	$ 274,674	$ 366,586	$ 299,623	$ 321,564	$ 333,036
Common Shares (thousands)								
Weighted average during period - basic	**216,598**	216,443	216,443	216,287	215,350	215,349	215,337	215,274
Weighted average during period - diluted	**216,598**	216,900	216,621	216,287	215,350	215,349	215,337	215,274
Outstanding at period end	**217,115**	216,443	216,443	216,443	215,350	215,350	215,349	215,328

(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), $52.0 million and $75.0 million in net impairment (reversal) charges against properties for the three months ended December 31, 2016, September 30, 2016 and September 30, 2015, 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 and second 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. 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 were 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 have mostly trended with the Canadian Light Sweet and AECO benchmarks which decreased throughout 2015 with the Canadian Light Sweet benchmark not beginning to recover until the second quarter of 2016 while the AECO benchmark recovered in third quarter of 2016. 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. Our dispositions of non-core assets 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 April 1, 2017 and ended June 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, decommissioning obligation 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 and decommissioning obligation. We use net surplus (debt) to assist us in understanding our liquidity at specific points in time. We exclude the current portion of decommissioning obligation as it is not a financial instrument. 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 and operating expense is calculated as production and operating expense less processing and gathering revenues. We use net production and operating expense to determine the current periods’ cash cost of operating expenses and net production and operating 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: that all four wells from our 2017 four well drilling program at our Birley/Umbach area are scheduled to be on-stream during the fourth quarter of 2017, our 2017 year end production guidance, expectations regarding crown royalties and the receipt of additional credits in 2017, our expectation that the new gas handling agreement will significantly improve our go-forward drilling economics and reduce our operating costs, future G&A cost reductions and the realization thereof, our expected future production costs, plans and operations including our intention to concentrate on our Montney assets, the amount and composition of our 2017 capital program and how we intend to fund the program, that we expect to remain undrawn on our demand revolving credit facility through 2017, the expected decrease in our net production expense and G&A in the fourth quarter of 2017 and our expectation that as we begin to increase production at Birley/Umbach our cost structure and profitability will improve significantly, future exploration and development activities and the timing thereof and how we intend to manage our company as well as our guidance regarding average and ending production for 2017, capital expenditures for 2017 and net surplus at December 31, 2017 set forth under the heading “Outlook”. 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 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		**Natural Gas**	
bbl	barrels	mcf	thousand cubic feet
bbl/d	barrels per day	mmcf	million cubic feet
NGLs	natural gas liquids	mcf/d	thousand cubic feet per day
		mmbtu	million British Thermal units
		GJ	gigajoule
		GJs	gigajoules
		GJs/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.