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. ("CEI" or the "Corporation") and its subsidiaries, both wholly and partially owned, (collectively, "our", "we" or "us") for the three months and years ended December 31, 2017 and 2016 and should be read in conjunction with our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2017 and 2016 (the "Financial Statements"). This MD&A is based on information available as at March 8, 2018.

The term "fourth quarter" and "reported year" or similar terms are used throughout this document and refer to the three months and year ended December 31, 2017, respectively. The term "current reporting periods" or similar terms are used throughout this document to refer to both the three months and year ended December 31, 2017, in this respective order. The term "same period(s) of 2016" and "comparative period(s)" or similar terms are used throughout this document and refer to the three months or (and) year ended December 31, 2016, in this respective order, depending on the 2017 period(s) under discussion.

This MD&A contains measures which are not prescribed by International Financial Reporting Standards ("IFRS") ("non-GAAP") and, therefore, may not be comparable with the calculations of similar measures presented by other companies. 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, 2017 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The Financial Statements have been prepared in accordance with IFRS issued by the International Accounting Standards Board. They include the accounts of our direct subsidiaries, all of which are wholly owned with the exception of Tournament Exploration Ltd., which subsequently changed its name to Craft Oil Ltd. and then Craft Oil Inc. ("Craft"). Our comparative periods' accounts and operating results include those of Craft from June 10, 2016, the date we acquired 70% of the common shares in a predecessor of this company to December 12, 2016, the date that our shareholdings in Craft were distributed to our shareholders as at the close of business. 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. For the comparative period(s) from June 10, 2016 to December 12, 2016, we adjusted for the minority interest share in the financial accounts of Craft through the non-controlling interest on the consolidated statements of operations and comprehensive loss. In this MD&A we did not adjust for the non-controlling interest in Craft's production volumes.

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 (the “Closing Date”), 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 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 (the “PSA”).

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"). We recognized the fair value of 152,251,953 Craft shares distributed to our shareholders as at December 12, 2016 through a $24.0 million charge directly to our deficit. On a net asset fair value basis, this equated to $0.16 per distributed Craft share.

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 December 31		Year ended December 31	
	2017	2016	**2017**	2016
OPERATIONS				
Production [1]				
Natural gas liquids (boe/d)	**551**	613	**470**	637
Natural gas (mcf/d)	**19,240**	21,548	**17,602**	24,631
Crude oil (bbl/d)	**21**	451	**22**	768
Average daily production (boe/d) [2]	**3,779**	4,655	**3,425**	5,510
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 51.87**	$ 40.70	**$ 47.89**	$ 26.35
Average natural gas price ($/mcf)	**$ 0.99**	$ 3.31	**$ 1.95**	$ 2.06
Average oil price ($/bbl)	**$ 76.96**	$ 71.98	**$ 62.27**	$ 52.01
Netback [3]				
Average commodity pricing ($/boe)	**$ 13.02**	$ 27.67	**$ 16.97**	$ 19.51
Royalty (expense) recovery ($/boe)	**$ (0.08)**	$ (2.84)	**$ 0.05**	$ (1.19)
Realized gain (loss) on commodity price contracts ($/boe)	**$ 3.83**	$ (0.35)	**$ 3.02**	$ 0.50
Net production expense ($/boe) [3]	**$ (11.06)**	$ (11.88)	**$ (11.57)**	$ (13.61)
Operating Netback ($/boe) [2] [3]	**$ 5.71**	$ 12.59	**$ 8.45**	$ 5.21
Wells Drilled (net)				
Total natural gas wells drilled (net)	**-**	2.64	**3.63**	2.64
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 4,499**	$ 10,631	**$ 21,271**	$ 36,943
Adjusted funds flow (outflow) [3]	**$ 1,100**	$ 1,713	**$ 4,978**	$ (1,004)
Per share - basic & diluted ($/share)	**$ 0.01**	$ 0.01	**$ 0.02**	$ (0.00)
Net (loss) income	**$ (21,160)**	$ 6,427	**$ (16,914)**	$ (54,773)
Per share - basic and diluted ($/share)	**$ (0.10)**	$ 0.03	**$ (0.08)**	$ (0.25)
Capital expenditures	**$ 7,253**	$ 4,177	**$ 39,044**	$ 9,211
Net (debt) surplus [3]	**$ (711)**	$ 15,138	**$ (711)**	$ 15,138
Total assets	**$ 130,571**	$ 139,975	**$ 130,571**	$ 139,975
Common Shares (thousands)				
Weighted average during period				
- basic	**218,517**	216,443	**217,174**	215,860
- diluted	**218,517**	216,621	**217,174**	215,860
Outstanding at period end	**223,565**	216,443	**223,565**	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) May not be additive due to rounding.

(3) 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.

Comparison of Fourth Quarter Guidance to Actual Results

The following table provides a comparison of our 2017 revised guidance as announced on November 9, 2017 and our actual results:

($ millions, except boe/d)	2017 Revised Guidance	2017 Actuals
Average production (boe/d)	3,600 - 3,700	3,425
Exit production (boe/d)	6,300 - 6,500	3,572
Capital expenditures	$ 40.0	$ 39.0
Net debt [(1)]	$ (2.7)	$ (0.7)

(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.

Our average production during the reported year was lower than our revised guidance as a result of an unforeseen pipeline integrity issue on Enbridge's Oak 16" gathering line (the "Oak Pipeline") that restricted our Birley/Umbach and Martin Creek production in December 2017 through to the date of this report. This also constrained our exit production despite the on-time December commissioning of the Birley/Umbach facility expansion from 25 mmcf/d to 50 mmcf/d. We did achieve peak production of 5,170 boe/d on December 24, 2017, despite continued restrictions and with only two (1.63 net) of our four (3.63 net) new Birley/Umbach wells being on-stream. Our actual capital expenditures are consistent with the revised guidance. For the reported year, we incurred expenditures on the previously mentioned facility expansion in addition to completing, equipping and tying-in seven (6.27 net) Birley/Umbach wells. Four (3.63 net) of these seven Montney gas horizontal wells were drilled in the reported year. Our net debt at the end of 2017 was favorable to our revised guidance as a result of our flow-through common share issuance on December 11, 2017 which raised net proceeds of $1.9 million (see "Flow-through Common Share Issuance").

Operations

Petroleum and Natural Gas Production Volumes

	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Natural gas liquids (boe/d)	**551**	613	**470**	637
Natural gas (mcf/d)	**19,240**	21,548	**17,602**	24,631
Crude oil (bbl/d)	**21**	451	**22**	768
Total (boe/d)	**3,779**	4,655	**3,425**	5,510

Total Production Volumes

During the current reporting periods, our production decreased by 876 boe/d and 2,085 boe/d compared to the same periods of 2016. Integrity issues on the Oak Pipeline restricted our current reporting periods' volumes. Our reported year volumes were significantly impacted by a longer than scheduled turnaround at the Enbridge McMahon gas plant (the "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 future area infrastructure development optionality, 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 the proposed TCPL's North Montney expansion anticipated to be complete in 2019 or 2020.

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. Initial production rate declines, as expected, from our Birley/Umbach wells brought on-stream mid-February 2016 and other previously drilled wells in that area, excluding days where production was restricted, also resulted in lower production volumes of approximately 385 boe/d for the reported year compared to the same period of 2016. 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, was the addition of 1,100 boe/d of production from three (2.64 net) wells at Birley/Umbach which we 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 three Birley/Umbach wells we increased this area's reported year production volumes in comparison to the same period. Also contributing to the reported year production volumes were the reactivations of our Boundary Lake North field during the first quarter of 2017 and our Martin Creek and Black Conroy fields late during the third quarter of 2016. We produced an additional 800 boe/d from these three fields during the reported year compared to the same period of 2016. As a result of our increased BC production, we were refunded our $3.0 million Liability Management Ratio deposit from the BC Oil & Gas Commission during the second quarter of 2017.

During the reported year, we drilled, completed and tied-in 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 approximately 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 during the fourth quarter but only flowed at restricted rates for reasons already explained. With the on-time commissioning of our Birley/Umbach facility expansion we now have the capacity to process production from all of our 13 (11.23 net) Birley/Umbach wells once the Oak Pipeline is temporarily replaced as expected by April 2018. Also, there are no significant planned McMahon Plant outages during 2018.

Natural Gas and Natural Gas Liquids Production ("NGL") Volumes

Our concentrated production of natural gas and its associated liquids production in BC for the current reporting periods decreased compared to the same periods of 2016 due to third party restrictions including integrity issues on the Oak Pipeline. In addition, the absence of the Subject Assets and the Craft legacy properties further decreased our current reporting periods' production compared to the same periods of 2016. Partially offsetting the reported year decrease 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 production volumes for the current reporting periods also partially offset decreases compared to the same periods 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 predominately 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 December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2017**	2016	**2017**	2016
Natural gas liquids sales	**$ 2,628**	$ 2,296	**$ 8,208**	$ 6,147
$/boe	**51.87**	40.70	**47.89**	26.35
Natural gas sales	**$ 1,746**	$ 6,567	**$ 12,503**	$ 18,578
$/mcf	**0.99**	3.31	**1.95**	2.06
Oil sales	**$ 152**	$ 2,986	**$ 503**	$ 14,619
$/bbl	**76.96**	71.98	**62.27**	52.01
Petroleum & natural gas revenue	**$ 4,526**	$ 11,849	**$ 21,214**	$ 39,344
$/boe	**13.02**	27.67	**16.97**	19.51

Our petroleum and natural gas revenues decreased for the current reporting periods compared to the same periods of 2016. These decreases were the result of both lower production volumes and realized natural gas pricing but as partially offset by higher realized 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 changes in 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 Montney play focused company. This is because natural gas, on a heating equivalent basis, receives a lower price.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2017	2016	**2017**	2016
Natural gas liquids				
Canadian light sweet [1] ($/bbl)	**$ 65.68**	$ 60.76	**$ 61.85**	$ 52.80
Natural gas				
AECO gas [2] ($/mcf)	**$ 1.72**	$ 3.11	**$ 2.20**	$ 2.18
BC Westcoast Station 2 [3] ($/mcf)	**$ 0.60**	$ 2.38	**$ 1.59**	$ 1.75
Chicago City Gate[4] ($/mcf)	**$ 3.55**	$ 3.86	**$ 3.74**	$ 3.19

(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 $51.87/boe and $47.89/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 79% and 77% for the current reporting periods which increased compared to approximately 67% and 60% 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 year. Had the BC Government not reclassified this well the comparative year ended NGL revenue and pricing would have been $7.4 million or $31.94/boe. These higher ratios were caused by the prices of propane through to 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 prices of $0.99/mcf and $1.95/mcf during the current reporting periods decreased compared to $3.31/mcf and $2.06/mcf for the same periods 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 Montney play focused company, the AECO benchmark no longer became significant to our current periods' realized natural gas sales prices.

During the current reporting periods, compared to the same periods of 2016, we also 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 reported year we sold 25% of our natural gas production at the Chicago City Gate benchmark compared to 14% in the same period 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 offset the record low fourth 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. During January and February 2018, we observed higher Station 2 pricing. However we are attributing this higher price to producers, such as ourselves, whose production is being restricted by third party constraints, resulting in lower volumes at Station 2. We remain optimistic that Station 2 pricing will increase as other producers' restrictions to access AECO pricing are eased. We continue to pursue transportation alternatives with more favorable pricing.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Royalty expense (recovery)	**$ 27**	$ 1,218	**$ (57)**	$ 2,401
Per sales ($/boe)	**$ 0.08**	$ 2.84	**$ (0.05)**	$ 1.19
Percent of revenues (%)	**1**	10	**-**	6

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 were located throughout Alberta with higher royalty rates associated with crude oil volumes. The reported year's recovery was 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 granted $1.3 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 have been generated by specific wells. We recognized $0.2 million and $0.9 million of these credits 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 $6.5 million in remaining royalty credits. The 11 (9.47 net) Birley/Umbach wells that have qualified for this credit program bear a minimum crown royalty rate of either 3% or 6% prior to applying the credits from the Infrastructure Program. We expect a twelfth well (1.0 net) to qualify for the deep well credit in 2018. 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 flow. 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, in accordance with the terms of our demand credit facility, if we have either an adjusted working capital deficit (see "Credit Facilities") or debt draws, we are required to enter into commodity price contracts covering a minimum amount of our forecasted twelve month combined production volumes. We continuously review the need or requirement to utilize financial contracts.

When we have commodity price contracts outstanding at the end of a reporting period, they are reported at their approximated fair value on the date of the financial statements. This estimated fair value is partially determined through the difference in the referenced market forward price of the respective commodity over the remaining periods of the contracts compared to our received price multiplied by the remaining notional volumes. Volatility in forward commodity pricing and decreases 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 the settlement 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 December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Realized (gain) loss on commodity price contracts	**$ (1,332)**	$ 151	**$ (3,770)**	$ (1,010)
Unrealized loss (gain) on commodity price contracts	**1,153**	2,766	**(154)**	4,695
(Gain) loss on commodity price contracts	**$ (179)**	$ 2,917	**$ (3,924)**	$ 3,685
Realized gain (loss) on commodity price contracts ($/boe)	**$ 3.83**	$ (0.35)	**$ 3.02**	$ 0.50

During the current reporting periods, we realized gains on our AECO price indexed contracts as this benchmark was lower than our received price. 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 $1.74/mcf and $2.53/mcf compared to our reported prices of $0.99/mcf and $1.95/mcf.

As there were no outstanding commodity price contracts at December 31, 2017, our unrealized loss of $1.2 million and unrealized gain of $0.2 million for the current reporting periods resulted from reversing each period's opening mark-to-market position.

Subsequent to December 31, 2017, we entered into the following commodity price contract:

Indexed Price	Notional Volumes	Company's Received Price	Period
Chicago City Gate	6,000 mmbtu/d	US$2.68/mmbtu	February 1, 2018 to March 31, 2019

As at December 31, 2017, we had net debt of $0.7 million and subsequently entered into the above commodity price contract. We estimate that the notional volumes of 6,000 mmbtu/d covers no less than 30% of the forecasted twelve month combined production volumes.

Net Production Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Production & operating	**$ 4,157**	$ 5,256	**$ 15,476**	$ 29,618
Less:				
Processing & gathering revenues	**(312)**	(168)	**(1,006)**	(2,178)
Net production expense [(1)]	**$ 3,845**	$ 5,088	**$ 14,470**	$ 27,440
Net production expense ($/boe) [(1)]	**$ 11.06**	$ 11.88	**$ 11.57**	$ 13.61
Production expense ($/boe)	**$ 11.96**	$ 12.27	**$ 12.38**	$ 14.69

(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 reported year's 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.

The current reporting periods' operating costs on a boe basis were higher than expected due in part to lower than expected production volumes. These lower than expected volumes were caused by the previously mentioned third party production restrictions which had the effect, on a boe basis, of increasing our fixed operating costs relative to total operating costs. Specifically, for the reported year our production was affected by the extended McMahon gas plant turnaround in June, July and August. Our properties were shut-in or materially restricted in these months for up to 66 days. Also, for the current reported periods, the Oak Pipeline integrity issue caused further volume restrictions from November through to the date of this report. To prevent our production from freezing, we also incurred higher labour and steamer costs to flow restricted volumes through December's extremely cold weather. These costs could have been avoided had our production been unimpeded. Testing costs for our new four (3.63 net) Birley/Umbach horizontal wells were also higher than expected because each test, which requires 12 to 24 hours, took considerably longer due to interruptions caused by the Oak Pipeline restrictions. Higher reported year fluid hauling costs were due to road bans caused by wet spring weather conditions resulting in partial truck loads in addition to higher than forecast sand separator, 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. These fields' higher operating cost structure relative to our Birley/Umbach field further contributed to higher operating costs on a boe basis. We also incurred startup-costs at Birley/Umbach on seven (6.27 net) wells and the commissioning of this area's facility expansion. Finally, we incurred seasonal costs including the repair and maintenance of our processing plants and our Birley/Umbach access road.

During 2018, we expect lower operating costs on a boe basis. There are no significant scheduled McMahon Plant turnarounds and the Oak Pipeline is expected to be temporarily replaced by April 2018. With these third party restrictions eased, this should increase our production volumes during 2018 and allow us to avoid incremental costs associated with such restrictions over winter months. Increases in our 2018 volumes, compared to the current reported periods, will also result from our Birley/Umbach facility expansion that will allow us to produce from all of this area's 13 (11.23 net) wells. This will further lower, on a boe basis, fixed operating costs relative to total operated costs. We do not anticipate significant maintenance costs on our operated facilities. We are also making arrangements to further lower our cost structure including increasing our truck loads during the spring road ban restrictions through a consortium of Montney producers and the BC Government.

The processing and gathering revenue for the reported year decreased compared to the same period 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. This new toll revenue also resulted in higher fourth quarter processing and gathering revenue.

Operating Netback

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

	Three months ended December 31		Year ended December 31	
Per sales ($/boe)	**2017**	2016	**2017**	2016
Realized sales price	**$ 13.02**	$ 27.67	**$ 16.97**	$ 19.51
Royalty (expense) recovery	**(0.08)**	(2.84)	**0.05**	(1.19)
Realized gain (loss) on commodity price contracts	**3.83**	(0.35)	**3.02**	0.50
Net production expense (1)	**(11.06)**	(11.88)	**(11.57)**	(13.61)
Operating netback (1)	**$ 5.71**	$ 12.59	**$ 8.45**	$ 5.21

(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. Operating netback may not be additive to due rounding.

Our operating netbacks were affected during the current reporting periods compared to the same periods of 2016, due to both lower realized natural gas sales pricing and a lower proportion of the comparatively higher priced crude oil sales. For the fourth quarter, compared to the same period of 2016, on a boe basis this was partially offset by lower royalties and net production expense in addition to increases in natural gas liquid pricing and realized gains on commodity price contracts. These lower expenses and higher liquids pricing and commodity price contract gains more than offset the lower realized natural gas sales price resulting in an increase in the reported year's operating netback compared to the same period of 2016. On a boe basis, our transition to a Montney focused play with its associated lower cost structure resulted in decreases to our current reporting periods' expenses.

General & Administrative ("G&A") Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
G&A expense before recoveries	**$ 1,661**	$ 3,340	**$ 8,301**	$ 13,627
Recoveries	**(737)**	(856)	**(3,057)**	(4,392)
G&A expense	**$ 924**	$ 2,484	**$ 5,244**	$ 9,235
Per sales ($/boe)	**$ 2.66**	$ 5.80	**$ 4.19**	$ 4.58

The comparative periods include $0.7 million and $1.6 million of Craft G&A expenses which were absent in the current reporting periods as a result of the Craft Share Distribution.

During the reported year, 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 an onerous contract non-cash charge of $1.6 million (see "Onerous Contract and Indemnifications") as offset against a provision. As a result of this recognition, $0.2 million and $0.4 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 mid-2019 upon our lease expiration.

We have continued to focus on improving our G&A cost structure through cost cutting initiatives. 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 reported year 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 $1.3 million during the reported year 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 before recoveries decreased $0.8 million and $3.3 million during the current reporting periods compared to the same periods of 2016.

As a result of these decreases, our G&A on a boe basis decreased during the current reporting periods despite previously discussed production restrictions.

We continue to assess our G&A expenses and make reductions where feasible. This assessment resulted in us reducing our headcount by approximately 25% during the first quarter of 2018.

Transaction, Distribution and Severance Costs

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Transaction, distribution & severance costs	**$ 34**	$ 1,422	**$ 705**	$ 3,162

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 comparative periods, costs were also incurred in connection with the distribution of Craft shares to our shareholders. During the comparative year, transaction costs were also incurred in connection with the conveyance of the Subject Assets to Craft and the corresponding Craft acquisition.

Exploration and Evaluation Expense (Recovery)

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Exploration & evaluation expense (recovery)	**$ 11**	$ (239)	**$ 272**	$ 729

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. During both the fourth quarter and the same period of 2016 we sold $0.1 million and $0.3 million, respectively, of seismic data which reduced our reported exploration and evaluation expense.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Depletion, depreciation & amortization	**$ 3,148**	$ 4,189	**$ 11,622**	$ 25,649
Depletion per sales ($/boe)	**$ 7.66**	$ 7.80	**$ 7.79**	$ 10.86

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. The current reported periods' decreased rates were also caused by increases in the December 31, 2017 measure of our proved plus probable reserves. Similarly, we previously reported an increase in the December 31, 2016 measure of our proved plus probable reserves which also contributed to the reported year's lower depletion rate. Amortization expense during the current reporting periods decreased $0.4 million and $1.9 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.

Our proved plus probable reserves of 33,910 mboe at December 31, 2017, increased from 26,488 mboe at December 31, 2016. This increase was the result of four (3.63 net) Birley/Umbach horizontal wells drilled and completed in 2017 and the addition of ten undeveloped well locations. We now have a total of 33 undeveloped well locations in our December 31, 2017 measure of proved plus probable reserves. Our future development costs, which were included in our depletion rate, were $139.1 million at December 31, 2017 (December 31, 2016 - $115.1 million).

Impairment of Development & Production and Exploration & Evaluation Assets, Net of Reversal

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Impairment of development & production assets and exploration & evaluation assets, net of reversal (recovery)	**$ 17,100**	$ (10,900)	**$ 17,100**	$ 41,100

Evaluation of Composition of Cash Generating Units

We reviewed and adjusted our Cash Generating Units ("CGUs") as a result of changes to our property mix achieved through core area development, significant property dispositions and the Craft Share Distribution on December 12, 2016. Our petroleum and natural gas properties are located in the Peace River Arch area with a commodity mix weighted to natural gas and its associated liquids. We concluded that we had one CGU, the Peace Arch River area, as at December 31, 2017 and 2016. Prior to the Craft Share Distribution, completed on December 12, 2016, we also had the *Craft CGU*.

Impairment or Reversal of Impairment of D&P Assets.

Peace River Arch CGU

Despite increases in proved and probable reserves, we identified evidence indicating impairment in the December 31, 2017, carrying value of our development and production assets. This evidence was a significant sustained reduction in short term forward BC Station 2 natural gas pricing. As a result, on the December 31, 2017 carrying value, we tested for impairment on our one remaining Peace River Arch CGU. For the reported year, this test revealed impairment of $17.1 million as opposed to the comparative year's reversal of impairment of $17.0 million.

The CGU's recoverable value of $110 million was estimated using a value in-use calculation based on a December 31, 2017, independently prepared reserve report. We used this report's expected future net revenues anticipated to be produced from the combined reserve categories proved developed, proved undeveloped and probable reserves, using before income tax discount rates of 10%, 15% and 20%, as respectively applied to each reserve category, in addition to the following January 1, 2018 forward commodity price estimates (and their comparatives):

	Edmonton Condensate & Natural Gasolines ($/bbl) (1)		British Columbia Station 2 Natural Gas ($/mmbtu) (2)	
As at December 31,	**2017 (3)**	**2016 (3)**	**2017 (3)**	**2016 (3)**
2018	$ 73.10	$ 75.80	$ 1.78	$ 2.78
2019	$ 74.40	$ 78.60	$ 2.28	$ 3.04
2020	$ 78.00	$ 84.30	$ 2.69	$ 3.34
2021	$ 83.70	$ 89.80	$ 3.14	$ 3.64
2022	$ 86.00	$ 91.60	$ 3.34	$ 3.69
Thereafter, increasing per year	2%	2%	2%	2%

(1) Central market point for Canadian condensate.
(2) Central market point for Canadian natural gas.
(3) Source: McDaniel & Associates Consultants Ltd. price forecast, effective January 1, 2018 and 2017.

Craft CGU

Subsequent to December 12, 2016, Craft entered into purchase and sale agreements to dispose of substantially all of its petroleum and natural gas properties. The selling price in these agreements was used as a basis to estimate the fair value of Craft's petroleum and natural gas properties, net of decommissioning obligations. This evaluation resulted in an impairment charge to the Craft CGU of $57.8 million for the comparative year. It also resulted in an impairment charge to Craft's E&E Assets of $0.3 million. Combined with the $17.0 million reversal of prior years' impairment expense from our one remaining CGU, the impairment of D&P Assets and E&E assets, net of reversal, for the comparative year was $41.1 million.

Loss (Gain) on Dispositions of Properties

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Loss (gain) on dispositions of properties	**$ -**	$ 224	**$ (10,926)**	$ (5,796)

During the reported year, we completed the sale of certain 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, in addition to Craft's October 2016 disposition of certain Subject Assets, for total proceeds of $21.4 million.

Realized Loss on Sale of Notes

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Realized loss on sale of notes	**$ -**	$ 648	**$ -**	$ 648

During the comparative periods, the net consideration from property dispositions included $4.5 million of a buyer's units (the "Units") as held by Craft. The Units were comprised of par value 10.5% senior secured notes (the "Notes") due in 2021 and 7.38 million purchase warrants (the "Warrants"). Each Warrant entitles the holder to acquire one common share of the buyer at a price of $0.18 per share. The Warrants expire November 15, 2021. We bifurcated the value of the Units between the Notes and the Warrants. The fair value of the Warrants was estimated using received bids. The fair value of the Notes was determined from the face value of the Units less the estimated fair value of the Warrants. Our fair value estimates for the Notes and Warrants was $4.2 million and $0.3 million, respectively. In November 2016, Craft sold all of the Notes for $3.6 million. This resulted in a realized loss on the sale of $0.6 million, during the comparative periods.

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Share-based compensation	**$ 215**	$ 558	**$ 906**	$ 2,243

We granted share options and restricted awards during the reported year. These granted awards had lower estimated fair values 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 lower share-based compensation for the current reporting periods compared to the same periods of 2016.

Bad Debt Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Bad debt expense	**$ 300**	$ 177	**$ 300**	$ 635

In an effort to manage our credit risk we continuously monitor and assess the collectability of our purchaser and joint arrangement partners' receivables in addition to our other receivable positions. For the current reporting periods, we identified $0.3 million of receivables due from joint arrangement partners that were deemed uncollectible.

Onerous Contract and Indemnifications

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Onerous contract and indemnifications	**$ 276**	$ -	**$ 1,837**	$ -

During the reported year, we recognized $1.8 million of non-cash charges as offset against provisions caused by the onerous portion of our Calgary head office lease contract and indemnifications provided to the buyer of our former Tunisian operations sold in 2014 (see "Provisions").

Deferred Customer Obligation Amortization

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Deferred customer obligation amortization	**$ (220)**	$ -	**$ (583)**	$ -

During the reported year, a customer transferred a section of pipeline to us 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 $0.2 million and $0.6 million of the deferred customer obligation.

Take or Pay Contract and Other (Gains) Losses

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Take or pay contract revenue	**$ (1,050)**	$ -	**$ (2,974)**	$ -
Take or pay contract expense	**$ 1,498**	$ -	**$ 3,500**	$ -
Other (gains) losses	**$ (443)**	$ (19)	**$ 105**	$ 617

During the reported year and its comparative period, we incurred a fee for a take or pay processing agreement which we partially mitigated by purchasing production from a third party. We expect to partially mitigate our continued exposure to this agreement's costs at least through to the first quarter of 2019. As we prepared for the January 1, 2018, adoption of IFRS 15 "Revenue from Contracts with Customers", we determined that we should have separately reported the take or pay revenue and the cost to purchase production. This immaterial correction had no effect on cash flows, net income (loss) or the balance sheet. The take or pay processing agreement expires in 2020. The fourth quarter other gain resulted from a review of stale payables.

Financing Expenses

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Interest & financing charges (income)	**$ 23**	$ 309	**$ (161)**	$ 802
Accretion of decommissioning obligation and onerous contract	**177**	374	**692**	2,192
Total	**$ 200**	$ 683	**$ 531**	$ 2,994

We reported interest & financing income of $0.2 million during the reported year 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 $0.3 million and $0.8 million as interest from our cash on hand was more than offset by interest on the debt held by Craft and the associated financing costs.

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.

Income Tax

We have not reported a deferred tax asset because it is not probable that we can utilize this asset against future taxable profit. At December 31, 2017, we had the following tax pools:

($ thousands)	December 31 2017
Canadian oil & gas property expense	$ 499
Canadian development expense	47,492
Canadian exploration expense	48,147
Undepreciated captial costs	34,651
Non-capital losses, net	271,954
Capital losses	10,987
Other	1,685
Total	$ 415,415

Non-Controlling Interest

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Net loss attributable to non-controlling interest	**$ -**	$ (3,028)	**$ -**	$ (20,625)

The net loss of Craft from June 10, 2016 to December 12, 2016, was $68.7 million. This net loss was caused by charges such as impairment, realized loss on sale of the Notes, financing costs, unrealized losses on price commodity contracts, transaction and severance costs. This resulted in a recovery from the net loss attributable to the 30% non-controlling interest.

Net & Comprehensive (Loss) Income

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Weighted average shares outstanding - basic (thousands)	**218,517**	216,443	**217,174**	215,860
Dilutive impact of share based awards (thousands)	**-**	178	**-**	-
Weighted average shares outstanding - diluted (thousands)	**218,517**	216,621	**217,174**	215,860
Net & comprehensive (loss) income	**$ (21,160)**	$ 6,427	**$ (16,914)**	$ (54,773)
Per share - basic & diluted ($/share)	**$ (0.10)**	$ 0.03	**$ (0.08)**	$ (0.25)

For the reported year we had a decrease in our net loss compared to the same period of 2016. This favorable change reflects a lower cost structure associated with our Montney transition. It also reflects higher gains on both the disposition of non-core properties and commodity price contracts. Unfortunately these gains were partially offset by lower natural gas pricing combined with restricted volumes. Absent in the reported year but as included in the comparative period is the net loss from the Craft operations through to the December 12, 2016 distribution of Craft shares to our shareholders. This net loss included $58.1 million of impairment charged against the Craft assets but was partially offset by $20.6 million of net losses attributable to the non-controlling interest.

For the fourth quarter, we reported an increase in the net loss caused by a $17.1 million impairment charge compared to the same period of 2016 when we reversed $17.0 million of prior years' impairment. This increased net loss is also due to both lower production volumes, caused by the Oak Pipeline restrictions, and natural gas pricing. Partially offsetting the increased net loss was higher natural gas liquid pricing and a lower cost structure associated with our Montney transition.

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 predominately Montney play company focused on the development of liquids-rich natural gas production from our Birley/Umbach core 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 reported year to dispose of non-core assets for a combined $17.8 million after customary adjustments with associated production volumes of 100 boe/d.

During 2017, we secured an increase in our demand credit facility to $18.0 million as a result of the test results of our most recent seven (6.27 net) Birley/Umbach horizontal wells. We remain undrawn on this facility through to the date of this report. We also completed a flow-through common share issuance in December 2017 for proceeds of $1.9 million, net of issuance costs. These proceeds were used to fund the drilling of two Birley/Umbach vertical exploratory wells during the first quarter of 2018 (see "Capital Expenditures"). We continue to evaluate options as supplemented by future adjusted funds flow to finance various 2018 capital program scenarios which are under consideration while preserving balance sheet strength and flexibility.

For the reported year, we financed capital expenditures from cash on hand, adjusted funds flow, a decrease in non-cash working capital and property dispositions.

Adjusted Funds Flow (Outflow)

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2017**	2016	**2017**	2016
Cash flow (outflow) from operating activities	**$ 2,635**	$ (1,517)	**$ 6,118**	$ (9,320)
Add back (deduct):				
Change in operating non-cash working capital	**(2,287)**	1,933	**(3,284)**	511
Provision expenditures	**707**	114	**1,167**	3,914
Exploration & evaluation expenses	**11**	(239)	**272**	729
Transaction, distribution & severance costs	**34**	1,422	**705**	3,162
Adjusted funds flow (outflow) (1)	**$ 1,100**	$ 1,713	**$ 4,978**	$ (1,004)
Per share - basic & diluted	**$ 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.

For the reported year, we are reporting an increase in adjusted funds flow to $5.0 million compared to an adjusted funds outflow of $1.0 million in the same period of 2016. This increase resulted from higher natural gas liquid pricing 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 fourth quarter's adjusted funds flow of $1.1 million decreasing compared to the $1.7 million in the same quarter of 2016. Despite historically low Station 2 benchmark pricing and restricted production volumes, our fourth quarter adjusted funds flow is the sixth consecutive quarter we have reported positive adjusted funds flow which coincides with our transition to a Montney focused play but as complemented by realized gains from commodity price contracts.

Net (Debt) Surplus

	December 31 2017	December 31 2016
($ thousands)		
Debt	$ -	$ -
Cash and restricted cash	4,341	16,129
Accounts receivable	3,490	6,658
Prepaids & deposits	1,373	3,569
Accounts payable, accrued liabilities & other	(9,915)	(11,218)
Net (debt) surplus [(1)]	$ (711)	$ 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 net debt of $0.7 million at December 31, 2017 compared to a net surplus of $15.1 million at December 31, 2016. This decrease of $15.8 million was caused by capital, provision, severance and exploration and evaluation expenditures of $40.8 million net of proceeds from property dispositions, adjusted funds flow and the issuance of flow-through common shares totalling $24.7 million, in addition to other non-cash working capital adjustments.

Credit Facilities

During the reported year, our previous credit facility agreement was terminated and we negotiated and secured a demand credit facility as amended with a Canadian chartered bank to increase the availability to $18.0 million (the "Demand Credit Facility") with the next semi-annual review scheduled for May 31, 2018. Given depressed Station 2 pricing combined with current restrictions on our production, it is likely that our lender will reduce the availability of the Demand Credit Facility. 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. At any time, the lender can request repayment of all outstanding drawn amounts under the Demand Credit Facility resulting in any future borrowings being classified as a current liability.

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 December 31, 2017, we had not made any draws on the Demand Credit Facility, but had outstanding letters of credit of $0.8 million, as secured by our lender, which reduced the available credit to $17.2 million (December 31, 2016 - $nil).

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 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 the greater of our adjusted working capital deficit or Demand Credit Facility draws are either up to $9.0 million or in excess of $9.0 million, within 60 days of the end of any such month, the terms of the Demand Credit Facility require that we enter into commodity price contracts covering no less than 30% or 50%, respectively, of our forecasted twelve month combined production volumes. For purposes of this compliance requirement, adjusted working capital deficit is current assets less current liabilities, excluding current commodity price contracts. At December 31, 2017, we had an adjusted working capital deficit. We subsequently entered into a commodity price contract, see "Financial Commodity Price Contracts", which we estimate covers no less than 30% of our forecasted twelve month combined production volumes.

As at December 31, 2017, we were in compliance with the foregoing financial covenant and other requirements under the Demand Credit Facility.

On June 10, 2016, as a result of the acquisition of Craft, we acquired outstanding debt. This debt was then disposed of on December 12, 2016. Borrowings under Craft's credit facility incurred interest at a rate equal to 9% per annum.

Capital Expenditures

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

	Three months ended December 31		Year ended December 31	
($ thousands)	**2017**	2016	**2017**	2016
Land & lease	**$ -**	$ 15	**$ 182**	$ 164
Drilling & completions	**82**	3,951	**22,712**	3,951
Facilities & equipment	**7,027**	-	**15,420**	4,083
Field expenditures	**7,109**	3,966	**38,314**	8,198
Capitalized G&A	**144**	211	**730**	1,013
Total	**$ 7,253**	$ 4,177	**$ 39,044**	$ 9,211
Proceeds from dispositions	**$ -**	$ 13,336	**$ 17,838**	$ 21,410

Late during the fourth quarter, we commissioned the on-time expansion of our Birley/Umbach facility to 50 mmcf/d. This $11.5 million net expansion provides us with the capacity to produce all of our 13 (11.23 net) Birley/Umbach wells, once third party restrictions are resolved, as expected by April 2018.

Our reported year’s 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. In addition, we drilled, completed and tied-in four (3.63 net) horizontal Montney gas wells at Birley/Umbach (the a-81-F, b-90-G, 02/d-5-K and b-14-K wells) on our D-93-F pad. The D-93-F pad wells cost on average $4.6 million per gross well. This higher average total gross cost per well resulted from each D-93-F pad well, on average, having longer lateral lengths and additional completion stages.

Our D&P Assets increased by $2.8 million during the reported year for a non-cash pipeline transfer from a customer (see “Deferred Customer Obligation Amortization”).

During the first quarter of 2018, we drilled two (2.0 net) vertical exploratory wells in the Birley/Umbach area for $2.1 million. These wells will help delineate 17 undrilled contiguous sections of 100% owned Montney rights (located three kilometres north of our main Montney land block and eight kilometres from the nearest well drilled into the Montney) by evaluating the pay thickness and reservoir quality throughout the entire 235 metre thick Montney zone. These vertical wells were mostly funded by the proceeds from our December 2017 flow-through share issuance. Our remaining first half of 2018 capital expenditures are limited to $1.3 million as we wait for commodity prices to improve.

Rationalization of Properties

During the reported year, we completed the sale of certain properties 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).

Provisions

Decommissioning Obligations

At December 31, 2017, the net present value of our decommissioning obligations was $31.1 million, an increase from $29.1 million at December 31, 2016. We estimate this net present value based on a total future undiscounted and uninflated liability of $31.7 million (December 31, 2016 - $31.2 million).

The net present value increase in the decommissioning obligations of $2.1 million was mostly caused by a $1.9 million change in estimate that resulted from decreases in long term risk-free rates and additions related to our 2017 drilling program and the commissioning of our facility expansion. We also recognized $0.7 million of accretion charges reflecting the increase in the obligation associated with the passage of time. Partially offsetting these increases was $0.4 million in expenditures.

As at December 31, 2017 and 2016, the estimated obligations include 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 obligations. At December 31, 2017 and 2016, the average risk-free interest rate of 2.20% and 2.34%, respectively, was used in order to calculate the present value of the obligation.

Onerous Contract and Indemnifications

During the reported year, we recognized a provision caused by the onerous portion of our Calgary head office lease contract. This provision represents the present value of the minimum future lease payments we are obligated to make under the estimated onerous portion of the non-cancellable lease contract less estimated recoveries. At December 31, 2017, the undiscounted amount of future cash flows to settle this provision was $1.2 million. These cash flows have been discounted using a risk-free discount rate of 1.58%. The onerous contract provision is estimated to be settled in future reporting periods through to June 2019.

We are involved in litigation and claims arising in the normal course of operations and from indemnifications provided to the buyer of our Tunisian operations in 2014. At December 31, 2017 and 2016, claims from a former Tunisian service provider and the Tunisian Tax Authority totaled $15 million. Storm Ventures International (BVI) Limited ("Storm BVI"), a wholly-owned subsidiary of CEI, has provided the buyer indemnifications for claims of this nature which are guaranteed by us. As of December 31, 2017, an estimate of probable future disbursements for these indemnifications, including professional costs, totaled $1.0 million. While the outcome of the remaining claims in excess of $1.0 million is not known with certainty, we are of the view that such claims are without merit and will represent our interests vigorously in any future legal or arbitration proceedings. See “Risk Factors”.

Share Capital

Authorized

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

Outstanding

Details of our outstanding share capital in addition to share options and share awards are as follows:

	December 31 2017	December 31 2016
Common shares outstanding	**223,564,601**	216,442,834
Share options	**10,276,884**	6,471,200
Restricted awards	**200,370**	349,241
Performance awards	**-**	381,790
Weighted average common shares - basic and diluted	**217,173,649**	215,860,123

As at March 7, 2018, we had 223,564,601 common shares, 15,548,882 share options, 314,600 restricted awards and nil performance awards outstanding.

Flow-through Common Share Issuance

On December 11, 2017, we completed the private placement of 6,450,000 common shares on a flow-through basis at a price of $0.31 per flow-through common share for total gross proceeds of $2.0 million. The flow-through common share issuance costs were $0.1 million resulting in net proceeds of $1.9 million. A premium of $0.3 million received on the flow-through common shares was recognized as a liability on the consolidated statements of financial position as determined from the difference between the total gross proceeds and the estimated fair value of the equivalent number of our common shares immediately preceding the date of the flow-through common share announcement. During the first quarter of 2018, we incurred the $2.0 million of qualifying Canadian exploration expenditures on the drilling of the two Birley/Umbach exploratory vertical wells. As a result, we expect during the first quarter of 2018 the flow-through common share premium will be amortized on the consolidated statements of operations and comprehensive loss.

New Class "A" Common Shares

In connection with the Craft Share Distribution, on December 12, 2016, each outstanding common share was exchanged for one new class "A" common share in our capital (which class "A" common shares were subsequently re-named common shares) and 0.70343 of a common share in the capital of Craft. All of our previous outstanding common shares were deemed to have been cancelled. The Craft share amount represents the pro-rata entitlement per common share to the 152,251,953 Craft shares held by us based on our 216,442,934 common shares issued and outstanding as at the close of business on December 12, 2016. A new common share does not have any pro-rata entitlement to a Craft share.

Commitments and Guarantees

At December 31, 2017, we had contractual commitments that require the following minimum future payments without giving effect to any offsetting third party agreements which, are anticipated to reduce some of these amounts:

	Year ended December 31					
($ thousands)	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Office leases	$ 1,593	$ 797	$ -	$ -	$ -	$ 2,390
Operating contracts	4,157	2,263	877	209	-	7,506
	$ 5,750	**$ 3,060**	**$ 877**	**$ 209**	**$ -**	**$ 9,896**

Office lease commitments relate to our head office in Calgary, Alberta. This office lease commitment excludes the undiscounted portion considered onerous (see "Onerous Contract and Indemnifications"). Operating contracts relate to minimal contractual payments if we do not benefit from the operating services.

We have also guaranteed indemnifications provided by our wholly owned subsidiary to the buyer of our former Tunisian operations (see "Onerous Contract and Indemnifications" and "Risk Factors").

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 reported year, the lender released its restrictions to this cash in connection with the execution of the Demand Credit Facility.

Off Balance Sheet Arrangements

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

Related Party Transactions

We determined that our key management personnel consist of our officers and directors. In addition to the salaries and directors fees paid to the officers and directors respectively, the officers and directors participate in our long-term share incentive plans, which include a share option plan and a restricted and performance award incentive plan. The officers' salaries, directors' fees and other benefits as mostly included in G&A expense and transaction, distribution and severance costs for the reported and comparable years totaled $2.2 million and $2.3 million, respectively. Long-term incentive benefits for our officers and directors as included in share-based compensation for the reported and comparable years totaled $0.6 million and $1.2 million, respectively.

Alberta Investment Management Corporation ("AIMCo"), as investment manager to Her Majesty the Queen in Right of the Province of Alberta ("HMQ"), maintains investment control and direction over approximately 36% of our outstanding common shares for the benefit of HMQ. Pursuant to a management and administration services agreement (the "Services Agreement") dated June 29, 2010 between 1542991 Alberta Ltd. ("WOGH GP") and our company, WOGH GP engaged our company to perform its duties under the partnership agreement and to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership in connection with the partnership business and to make all decisions relating thereto. WOGH Limited Partnership was formed to hold working interests in certain of our assets which are held by nominees of AIMCo on behalf of HMQ. As we manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership, we are reimbursed for such services. In accordance with the Services Agreement, we reported a recovery from WOGH Limited Partnership, as mostly reported against our G&A expense, of $1.1 million and $1.4 million for the reported and comparable years. The recovery for the reported and comparative years was generally determined from WOGH Limited Partnership's pro rata share as estimated at 14 percent of its and CEI's combined production volumes. At December 31, 2017, $0.1 million of this G&A recovery was included in accounts receivable (December 31, 2016 - $0.1 million).

Outlook

2017 marked a successful year for us as we moved from delineation to exploitation of our Birley/Umbach property. In early 2014, we drilled our first Montney test well at Birley at a time when others were not entirely convinced of its prospectivity. The results of that test well, along with our follow up wells, confirmed the presence of a large Montney resource and established a large drilling inventory for Chinook. Subsequent to our Birley discovery, we began to streamline our business by divesting of our international assets in Tunisia and transacting on all our non-core Alberta assets through either cash dispositions or share transactions.

Today we are a Montney focused company with a healthy balance sheet. During 2017 we were not able to show the full results and benefits of our newly streamlined operations due to low commodity prices and third party restrictions. Currently, we continue to produce at volumes less than our capability due to gathering system maintenance issues on the Oak Pipeline which are expected to be temporarily resolved by April 2018. In anticipation of weaker natural gas prices, we may voluntarily shut-in volumes through the summer months as we do not have large take or pay commitments that would force us to produce at low prices.

However, we believe that our capital program during the last few years which saw us drill and complete 13 (11.23 net) wells on our Birley/Umbach property as well as our on-time completion of our Birley facility expansion to 50 mmcf/d puts us in an excellent position to accelerate activity when commodity prices recover. We have confirmed the resources are there, now our objective will be to extract them efficiently and profitably. To that effect, although we are encouraged about the results of our exploitation program in 2017 and additional delineation work in 2018, we remain cautious on further capital expenditures until such time as commodity prices improve to a more constructive level. The capital program for the balance of 2018 will be minimal and continuously reviewed by management and the board of directors with adjustments made in response to changing market conditions.

We also believe that consolidation is required and would increase efficiencies among producers and streamline operations. We will continue to pursue opportunities that have the potential to generate additional value to our shareholders.

Selected Annual Information

Summarized information for the reported year and the two preceding years appears below:

Year ended December 31		**2017**		**2016**		**2015**
($ thousands, except per share amounts)						
Petroleum & natural gas revenue, net of royalties	**$**	**21,271**	$	36,943	$	49,701
Net loss [(1)]	**$**	**(16,914)**	$	(54,773)	$	(83,606)
Per share - basic & diluted ($/share)	**$**	**(0.08)**	$	(0.25)	$	(0.39)
Total assets	**$**	**130,571**	$	139,975	$	321,564
Long-term liabilities [(2)]	**$**	**33,337**	$	27,767	$	96,042

(1) Includes $17.1 million, $41.1 million and $75 million of net impairment charges for the years ended December 31, 2017, 2016 and 2015, respectively.
(2) Includes loans and borrowings, provisions and other long-term liabilities.

Factors That Have Caused Variations over the Years

Petroleum & natural gas revenues, net of royalties decreased each successive year from 2015 to 2017. These decreases were due to lower production volumes and declining average realized commodity pricing. The lower production volumes from 2015 to 2016 were caused by property dispositions and the voluntary shut-in of production in response to declining commodity prices. Beginning in the reported year, our operating and financial results reflect the completion of our transition to a Montney play focused company. Although volumes increased from our owned portfolio of producing assets during the reported year compared to the prior year, the combined effect of the absence of the Subject Assets, third party restrictions on our production, a weighted average shift to natural gas and lower natural gas pricing resulted in a decrease in our revenues.

Net losses for the reported year and the two preceding years were due to the aforementioned lower revenues and impairment charges. These impairment charges combined with property dispositions (including the removal of the Subject Assets during 2016) contributed to each consecutive year's decrease in total assets.

The significant decrease in long-term liabilities from 2015 to 2016 resulted from lower decommissioning obligations caused by property dispositions and the absence of the Subject Assets. During the reported year, we recognized additional provisions (see "Provisions") and increased our decommissioning obligations estimate as caused by a lower average long-term risk free discount rate.

Please refer to "Operations" and other sections of this MD&A for detailed discussions on variations between the reported and comparative year and to our previous annual management's discussion and analysis for changes in the prior years.

Quarterly Information from Operations

Summarized information by quarter for the two years ended December 31, 2017, appears below:

	Dec. 31 2017	Sept. 30 2017	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016	Sept. 30 2016	Jun. 30 2016	Mar. 31 2016
Production Volumes								
Natural gas liquids (boe/d)	**551**	405	441	482	613	599	604	733
Natural gas (mcf/d)	**19,240**	14,109	19,065	18,022	21,548	28,972	22,776	25,215
Crude oil (bbl/d)	**21**	19	19	29	451	1,036	769	817
Average daily production (boe/d)	**3,779**	2,776	3,638	3,514	4,655	6,464	5,169	5,753
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 51.87**	$ 42.07	$ 44.48	$ 51.39	$ 40.70	$ 10.67	$ 25.78	$ 27.65
Average natural gas price ($/mcf)	**$ 0.99**	$ 1.20	$ 2.77	$ 2.71	$ 3.31	$ 2.22	$ 1.35	$ 1.43
Average oil price ($/bbl)	**$ 76.96**	$ 51.49	$ 59.55	$ 60.32	$ 71.98	$ 57.31	$ 50.59	$ 35.41
Operating Netback (1)								
Average commodity pricing ($/boe)	**$ 13.02**	$ 12.61	$ 20.22	$ 21.42	$ 27.67	$ 20.14	$ 16.50	$ 14.82
Royalty (expense) recovery ($/boe)	**$ (0.08)**	$ 0.52	$ (0.33)	$ 0.20	$ (2.84)	$ (0.77)	$ (0.44)	$ (0.99)
Realized gain (loss) on derivative contracts ($/boe)	**$ 3.83**	$ 6.54	$ 1.01	$ 1.38	$ (0.35)	$ 1.84	$ 0.14	$ -
Net production expenses ($/boe) (1)	**$ (11.06)**	$ (12.32)	$ (11.82)	$ (11.27)	$ (11.88)	$ (12.61)	$ (14.75)	$ (15.12)
Operating Netback ($/boe) (1)	**$ 5.71**	$ 7.35	$ 9.08	$ 11.73	$ 12.59	$ 8.60	$ 1.45	$ (1.29)
Wells Drilled (net)								
Total natural gas wells drilled (net)	**-**	-	3.63	-	2.63	-	-	-
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties	**$ 4,499**	$ 3,351	$ 6,583	$ 6,838	$ 10,631	$ 11,518	$ 7,550	$ 7,244
Adjusted funds flow (outflow) (1)	**$ 1,100**	$ 647	$ 1,195	$ 2,036	$ 1,713	$ 1,894	$ (1,721)	$ (2,890)
Per share - basic & diluted ($/share)	**$ 0.01**	$ -	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ (0.01)	$ (0.01)
Net (loss) income (2)	**$ (21,160)**	$ (3,923)	$ (2,253)	$ 10,422	$ 6,427	$ (35,905)	$ (12,520)	$ (12,775)
Per share - basic & diluted ($/share)	**$ (0.10)**	$ (0.02)	$ (0.01)	$ 0.05	$ 0.03	$ (0.17)	$ (0.06)	$ (0.06)
Capital expenditures	**$ 7,253**	$ 14,733	$ 8,235	$ 8,823	$ 4,177	$ 661	$ 1,347	$ 3,026
Net (debt) surplus (1)	**$ (711)**	$ 3,616	$ 18,294	$ 25,622	$ 15,138	$ 7,217	$ 6,207	$ 20,180
Total assets	**$ 130,571**	$ 155,799	$ 144,891	$ 148,665	$ 139,975	$ 274,674	$ 366,586	$ 299,623
Common Shares (thousands)								
Weighted average during period - basic	**218,517**	217,115	216,598	216,443	216,443	216,287	215,350	215,349
Weighted average during period - diluted	**218,517**	217,115	216,598	216,900	216,621	216,287	215,350	215,349
Outstanding at period end	**223,565**	217,115	217,115	216,443	216,443	216,443	215,350	215,350

(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 $17.1 million, ($10.9 million) and $52.0 million in impairment (net reversal) charges against properties for the three months ended December 31, 2017, 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 and financial measures during each of the 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 Montney play focused company. Production for 2017 trended with our Birley/Umbach property including this area's 2016 and 2017 development programs which added seven (6.27

net) horizontal wells that came on-stream in the first and fourth quarters of 2017 and the on-time December 2017 commissioning of our facility expansion. However, extended third party restrictions did not allow us to demonstrate our production potential during the second half of 2017.

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 flow have generally trended with the Station 2 and Western Canadian Select benchmark prices and volumes. Our net surplus has generally trended down as our capital expenditures exceeded our adjusted funds flow. An exception was the first quarter of 2017 as a result of proceeds received from non-core asset distributions.

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 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". The following are the more significant risk factors as copied from the AIF:

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs.

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of it properties.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada and uncertainty and reduced confidence in the oil and natural gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Corporation's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and the Corporation's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Corporation or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities.

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and natural gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Gathering and Processing Facilities and Pipeline Systems

Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas.

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of availability of capacity in any of the gathering and processing facilities and pipeline systems, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows. Announcements and actions taken by the governments of Alberta and British Columbia relating to the approval of infrastructure projects may continue to intensify leading to increased challenges to the interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on the proponents and the timing of receipt of approvals of major projects remains unclear.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

During 2017, the majority of the Corporation's natural gas production in northeast British Columbia was subject to the AECO – BC Station 2 differential which was -$0.56 per GJ and fluctuated between -$1.61 per GJ and +$0.50 per GJ from 2010 to 2016. Going forward, exposure to the AECO – BC Station 2 differential is reduced as a result of the Corporation contracting capacity on the Alliance Pipeline effective May 1, 2016 for delivery of natural gas to the Chicago area.

The Corporation has contracted pipeline transportation capacity for approximately 20% of total forecasted natural gas sales volumes in 2018 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut-in if capacity is allocated to other parties.

Risks Relating to Indemnification Rights

The Corporation is subject to risks relating to certain obligations guaranteed in favour of the buyer in connection with the Tunisian Disposition which was completed on August 19, 2014.

The Corporation has guaranteed the payment of the indemnification obligations of Storm BVI under a share purchase and sale agreement with the buyer dated as of June 14, 2014. These obligations relate to claims under the agreement in respect of breaches of certain representations, warranties and covenants of Storm BVI without a limit on amount or time. Consequently, any failure by Storm BVI to pay these indemnification obligations under the agreement with the buyer could result in a substantial payment by the Corporation to the buyer, which in turn could have a material adverse effect on the Corporation's working capital and financial condition. A copy of the share purchase and sale agreement is available on the Corporation's SEDAR profile.

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry.

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation may realize less on disposition than their carrying value on the financial statements of the Corporation.

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties.

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, cost overruns and marketing challenges.

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all and may be unable to market the oil and natural gas that it produces effectively.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability.

In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the Competition Act and the Investment Canada Act could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows.

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator.

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and gas companies that may be disproportionately affected by price instability. The recent Alberta Court of Queen's Bench decision, Redwater Energy Corporation (Re), found an operational conflict between the Bankruptcy and Insolvency Act and the Alberta Energy Regulator's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the Alberta Energy Regulator to the Supreme Court of Canada for final determination. In response to the decision, the Alberta Energy Regulator issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder.

The Demand Credit Facility is available at the discretion of the lender and may be demanded at any time. The amount authorized under the Demand Credit Facility is dependent on the borrowing base determined by the lender from time to time. Notwithstanding the discretionary and demand nature of the Demand Credit Facility, the Corporation is required to comply with covenants under the Demand Credit Facility which include certain financial ratio tests and, which may, from time to time, either affect the availability, or price, of existing and/or additional funding under the Demand Credit Facility. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with these covenants. A failure to comply with the applicable covenants (including the financial ratio tests) could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under the Demand Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Demand Credit Facility imposes operating and financial restrictions on the Corporation that include restrictions on paying dividends or repurchasing or making other distributions with respect to the Corporation's securities, incurring of additional indebtedness, providing guarantees, assuming loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Corporation's lender uses the Corporation's reserves, commodity prices, applicable discount rates and other factors, to periodically determine the Corporation's borrowing base. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices could result in a further reduction to the

Corporation's borrowing base, reducing the funds available to the Corporation under the Demand Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

If the Corporation's lender requires repayment of all or portion of the amounts outstanding under the Demand Credit Facility for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under the Demand Credit Facility, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Demand Credit Facility, the lender under the Demand Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to it to secure the indebtedness. The Demand Credit Facility is secured by the Corporation's consolidated assets.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Title to Assets

Defects in the title to the Corporation's properties may result in a financial loss.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation.

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Control by Principal Shareholder

The principal shareholder of the Corporation will have significant influence over the business and affairs of the Corporation.

Her Majesty the Queen in Right of the Province of Alberta ("HMQ") owns 80,357,142 Common Shares, representing approximately 36% of the current outstanding Common Shares. Alberta Investment Management Corporation ("AIMCo"), as investment manager to HMQ, maintains investment control and direction over the Common Shares for the benefit of HMQ. Accordingly, AIMCo will have significant influence over the business and affairs of the Corporation and may have the ability to take shareholder actions irrespective of the vote of any other shareholders, including the ability to prevent certain transactions that it does not believe are in HMQ's best interest. This significant influence may discourage transactions involving a change of control of the Corporation, including transactions in which minority shareholders of the Corporation might otherwise receive a premium for the Common Shares over the then-current market price.

Furthermore, AIMCo will generally have the right (subject to applicable securities laws) at any time to sell the Common Shares held by HMQ or to sell HMQ's interest in the Corporation to a third party without the approval of the minority shareholders and without providing for a purchase of such shareholders' shares. Accordingly, the Common Shares held by minority shareholders may be less liquid and worth less than they would be if AIMCo did not have the ability to influence matters affecting the Corporation.

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders.

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Expiration of Licences and Leases

The Corporation or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry.

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation does not pay dividends and there is no assurance that it will do so in the future.

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Corporation considers relevant.

Income Taxes

Taxation authorities may reassess the Corporation's tax returns.

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants.

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the *Business Corporations Act (Alberta)* which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act (Alberta)*.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Forward-Looking Information May Prove Inaccurate

Forward-Looking Information May Prove Inaccurate.

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements" of this MD&A.

Management Judgment and Estimation Uncertainty

The preparation of the Financial Statements requires management judgments and estimation uncertainty that affect the reported amounts at the date of the Financial Statements of assets, liabilities, shareholders' equity, revenues and expenses in addition to the disclosure of contingencies. Actual results could differ from those estimated. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Judgments that management has made through applying accounting policies that have the most significant effect on the Financial Statements are discussed below:

Cash Generating Units

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or group of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors our operations.

Impairment (reversal) indicators

Judgments are required to assess when impairment (reversal) indicators exist and impairment (reversal) testing is required. When assessing the recoverability of petroleum and natural gas properties, each CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less cost to sell and value in use. In determining the recoverable amount of assets, in the absence of quoted market prices or observed market transactions, impairment tests are based on reserve estimates, market value of undeveloped lands and other relevant assumptions.

Key estimates that management has made that affect the measurement of balances and transactions are discussed below:

Reserve estimates

Petroleum and natural gas reserves are used in the calculation of depletion, impairment and impairment reversals. Reserve estimates and their resulting cash flows are based on engineering data, probability assessments of reserve recoveries, future prices and costs, future production rates, discount rates and the timing and extent of future capital expenditures, all of which are subject to many uncertainties and interpretation. We expect that over time our reserve estimates will be revised, either upward or downward, based on updated information such as the results of future drilling, testing and production levels and changes to forward petroleum and natural prices and production costs.

Decommissioning obligation

Decommissioning obligations are recognized for the future decommissioning and restoration of property, plant and equipment. These obligations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. The expected timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

Deferred taxes

Tax interpretations, regulations and legislation in the jurisdictions in which we operate are subject to change. The deferred tax asset and/or liability is based on estimates as to the timing of the reversal of temporary differences, enacted or substantively enacted tax rates and the likelihood of assets being realized from future taxable earnings.

New Accounting Standards Not Yet Adopted

In July 2014, the IASB issued IFRS 9 “Financial Instruments” to replace IAS 39, “Financial Instruments Recognition and Measurement”. The new standard replaces the current multiple classification and measurement models for financial assets with a single model that has only two classifications categories: amortized cost and fair value. Additional amendments include a single “expected loss” impairment method and a substantially reformed approach to hedge accounting. We have substantially completed the analysis of the impact of adoption of this standard. Because our financial assets are already carried at amortized cost or fair value, this standard will not affect our measure of these financial instruments. We do not currently apply, nor do we intend to apply, hedge accounting to our financial instrument commodity price contracts on adoption of IFRS 9. We do anticipate changes to disclosures in the notes to our financial statements as a result of the adoption of this standard.

In May 2014, the IASB issued IFRS 15 “Revenue from Contracts with Customers” to replace International Accounting Standard (‘IAS”) 18, Revenue, IAS 11 “Construction Contracts”, and related interpretations. We enter into non-complex and routine revenue contracts with customers whose terms allow for the daily physical delivery of produced volumes that are priced at daily or monthly average spot prices. Performance obligations are met upon delivery of the volumes at third parties’ plant gates or terminals and the transaction price is established based on the date of delivery. We have completed reviewing our various revenue streams and underlying contracts with customers and have concluded that the adoption of this standard will not affect our net income (loss). However, we will expand the disclosures in the notes to our financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by commodity type.

As of January 1, 2018, we will retroactively adopt the above two standards.

In January 2016, the IASB issued IFRS 16 “Leases”. The standard requires entities to recognize lease assets and lease obligations on the statements of financial position. For lessees, there will be a single lease accounting model for all leases. There will no longer be a classification test between finance and operating leases. The lessee will recognize a Right of Use (“ROU”) asset and a lease liability, and the lease will be treated as an asset on a financed basis. There will be an optional exemption from the above for short term leases and leases of low value assets, defined at 12 months or less and an option for portfolio accounting on leases that have similar criteria. From the lessor’s perspective, there will still be a dual lease accounting model that follows the criteria set out in IAS 17. As of January 1, 2019, we will be required to adopt this standard. We are currently assessing all major leases including firm commitment contracts, which are expensed as operating leases for reclassification to the statements of financial position.

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2017 and have concluded that our disclosure controls and procedures are effective at December 31, 2017.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Our CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of our internal controls over financial reporting at December 31, 2017 and have concluded that our internal controls over financial reporting are effective at December 31, 2017.

We have designed our internal controls over financial reporting 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 flow (outflow) 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 flow (outflow) is a key measure to assess our ability to finance capital expenditures and when debt is drawn, to finance debt repayments. Adjusted funds flow (outflow) 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 (debt) surplus 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 (debt) surplus 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 the proposed TCPL's Northern Montney expansion, anticipated improvements to Station 2 pricing as other producers' restrictions to access AECO pricing are eased, forecasted nominal BC crown royalties through 2018, expected lower operating costs on a boe basis during 2018, increases in 2018 production volumes due to no significant schedule McMahon Plant turnaround and the Oak Pipeline being temporarily replaced by April 2018, the expected further lowering of fixed operating costs relative to total operated costs, no anticipated significant maintenance costs on our operated facilities, the amount and composition of our capital program for the first half of 2018 and how we intend to fund the program, that we may voluntarily shut-in volumes throughout the summer months in anticipation of weaker natural gas prices, that our previous capital program has put us in an excellent position to accelerate activity when commodity prices recover, that our capital plan for the remainder of 2018 will be minimal and will be continuously reviewed by management and the board of directors with adjustments made in response to changing market conditions, that we believe that consolidations would increase efficiencies among producers and streamline operations and that we will pursue opportunities that have potential to generate additional value to our shareholders, future exploration and development activities and the timing thereof and how we intend to manage our company. 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, the temporary replacement of the Oak Pipeline by April 2018, no significant 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 capital program for the first half and remainder of 2018, 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, anticipated third party restrictions, 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 capital program for the first half and remainder of 2018 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.

Reserves

The recovery and reserves estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

Future Oriented Financial Information

This MD&A, in particular the information in respect of our anticipated capital expenditures for the first half of 2018, 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
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
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
Chicago City Gate	Market point for eastern US 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.

Initial Production Rates

Any reference in this MD&A to initial, early and/or test or production/performance rates (including IP30, IP60 and IP90) are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating our aggregate production. The initial production or test rates may be estimated based on other third party estimates or limited data available at this time. In all cases in this news release initial production or test rates are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons. Well-flow test result data should be considered to be preliminary until a pressure transient analysis and/or well-test interpretation has been carried out.