2019 Management's Discussion and Analysis

CHINOOK energy inc

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The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. and its wholly owned subsidiaries (collectively, "our", "we" or "us") for the three months and years ended December 31, 2019 and 2018 and should be read in conjunction with our audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2019 and 2018 (the "Financial Statements"). This MD&A is based on information available at March 2, 2020.

The term "fourth quarter" or "year to date" (or "reported year") are used throughout this document and refer to the three months or year ended December 31, 2019, respectively. The term "current reporting periods" is used throughout this document and refers to both the three months and year ended December 31, 2019, in this respective order. The term "same period(s) of 2018" or "comparative period(s)" or similar terms are used throughout this document and refer to the three months or (and) year ended December 31, 2018, depending on the 2019 period(s) under discussion. The term "reported periods" is used throughout this document and refers to both the three months and years ended December 31, 2019 and 2018. The term "first quarter", "second quarter" or "third quarter" or similar terms are used throughout this document and refer to the three months ended March 31, 2019, June 30, 2019, or September 30, 2019, respectively.

This MD&A contains measures ("non-GAAP") which are not prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculations of similar measures presented by other companies including those in the oil and natural gas industry. 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, 2019 ("AIF"), once filed, can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Subsequent Events

Arrangement Agreement

Effective February 22, 2020, we entered into an arrangement agreement (the "Arrangement Agreement") pursuant to which Tourmaline Oil Corp. (the "Purchaser") has agreed to acquire all of the outstanding common shares ("Chinook Shares") of our company for cash consideration of $0.0675 per share (the "Transaction"). The Purchaser will assume our net debt as estimated upon closing. The Transaction is subject to various closing conditions, including receipt of Court approval and approval by our shareholders. An annual and special meeting (the "Meeting") of our shareholders has been called to consider, among other things, the Transaction. The Transaction will require the approval of 66$^2/_3$% of the votes cast by our shareholders present in person or by proxy at the Meeting. The Meeting is expected to be held on April 20, 2020 with closing of the Transaction anticipated to occur thereafter in late April upon satisfaction of all conditions precedent thereto. The Transaction offers a liquidity event and cash consideration to our shareholders. Upon closing of the Transaction, the Chinook Shares will be de-listed from the Toronto Stock Exchange. We can provide no assurances that the Transaction will close.

The Arrangement Agreement provides for a non-completion fee of $1.75 million. The non-completion fee is payable to the Purchaser in the event that the Transaction is not completed or is terminated by us in certain circumstances, including if we enter into an agreement with respect to a superior proposal or if our Board of Directors withdraws or modifies its recommendation with respect to the Transaction.

Demand Credit Facility Renewal

Following our execution of the Arrangement Agreement, on February 28, 2020, our lender renewed the demand credit facility agreement with an unchanged maximum availability of $10.0 million. This renewal waived the breaches of the *net debt to cash flow* financial covenant as at June 30, September 30 and December 31, 2019. This same financial covenant that is forecast to be in breach as at March 31, 2020, per the terms of the renewal has also been waived. The *minimum hedging requirement* was removed as a term of the demand credit facility agreement although additional reporting requirements were added and include weekly forecasted cash flows and monthly abandonment and reclamation activities in addition to requiring that the minimum liability management ratio ("LMR") does not fall below 1.3 as determined for us by the British Columbia Oil & Gas Commission ("BCOGC"). The next renewal is scheduled on May 31, 2020 but may be set at an earlier (or later) date at the sole discretion of the lender.

Future Operations and Liquidity

During the year to date, we drew $4.7 million of debt to finance our operating activities while there was an extended ongoing review of our demand credit facility. This extended ongoing review occurred during a very challenging environment as demonstrated by depressed natural gas pricing and continued weakness in general Canadian exploration and production industry and capital market conditions.

Although in our facility renewal we received waivers of past and forecasted financial covenant breaches, we are further forecasting that we will be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement as at June 30, 2020 assuming average realized natural gas and natural gas liquids' pricing of $1.86/mcf and $41.76/bbl, respectively.

In the event that the Transaction is not completed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the aforementioned market conditions and forecasted breach, no assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of these market conditions and forecasted breach or for any other reason. In such event, these material uncertainties cast significant doubt with respect to our ability to continue as a going concern.

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. They have also been prepared on a going concern basis, which presumes we will continue our operations for the foreseeable future and will be able to realize our assets and discharge our liabilities and commitments in the normal course of business (see "Future Operations and Liquidity"). As a result, the Financial Statements do not reflect adjustments and classifications of assets, liabilities, revenues and expenses which would be necessary if we were unable to continue as a going concern.

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 from our large contiguous Montney liquids-rich natural gas position at our Birley/Umbach property in northeast 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 1610, 222 – 3rd Avenue S.W., Calgary, Alberta, Canada T2P 0B4.

Operating and Financial Highlights

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
OPERATIONS				
Production (1)				
Natural gas liquids (boe/d)	**555**	405	**407**	565
Natural gas (mcf/d)	**16,469**	14,641	**12,950**	18,806
Crude oil (bbl/d)	**4**	12	**7**	19
Average daily production (boe/d) (2)	**3,304**	2,856	**2,572**	3,719
Sales Prices				
Average natural gas liquids price ($/boe)	**$ 39.75**	$ 43.56	**$ 42.26**	$ 59.87
Average natural gas price ($/mcf)	**$ 1.97**	$ 2.60	**$ 1.69**	$ 1.91
Average oil price ($/bbl)	**$ 62.11**	$ 54.13	**$ 61.48**	$ 69.15
Operating Netback (3)				
Average commodity pricing ($/boe)	**$ 16.55**	$ 19.72	**$ 15.33**	$ 19.11
Royalty expense ($/boe)	**$ (0.16)**	$ (0.14)	**$ (0.11)**	$ (0.08)
Realized gain (loss) on commodity price contracts ($/boe)	**$ 0.14**	$ (2.59)	**$ (0.64)**	$ (0.72)
Net production expense ($/boe) (3)	**$ (9.73)**	$ (14.01)	**$ (12.30)**	$ (11.63)
Operating netback ($/boe) (2) (3)	**$ 6.80**	$ 2.98	**$ 2.28**	$ 6.68
Wells Drilled				
Exploratory wells (net)	**-**	-	**-**	2.00
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$ 4,986**	$ 5,146	**$ 14,291**	$ 25,837
Cash (outflow) inflow from operating activities	**$ (48)**	$ (378)	**$ (3,634)**	$ 255
Adjusted funds flow (outflow)(3)	**$ 1,171**	$ (413)	**$ (2,034)**	$ 4,179
Per share - basic & diluted ($/share)	**$ 0.01**	$ -	**$ (0.01)**	$ 0.02
Net loss	**$ (13,998)**	$ (21,141)	**$ (42,263)**	$ (27,654)
Per share - basic and diluted ($/share)	**$ (0.06)**	$ (0.09)	**$ (0.19)**	$ (0.12)
Capital expenditures	**$ -**	$ 213	**$ 29**	$ 2,890
Net debt (3)	**$ 6,138**	$ 1,994	**$ 6,138**	$ 1,994
Total assets	**$ 63,797**	$ 101,416	**$ 63,797**	$ 101,416
Common Shares (thousands)				
Weighted average during period				
Basic & diluted	**223,682**	223,605	**223,672**	223,594
Outstanding at year end	**223,682**	223,605	**223,682**	223,605

(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.

Operating and Financial Results

Petroleum and Natural Gas Production Volumes

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Natural gas liquids (boe/d)	**555**	405	**407**	565
Natural gas (mcf/d)	**16,469**	14,641	**12,950**	18,806
Crude oil (bbl/d)	**4**	12	**7**	19
Total (boe/d)	**3,304**	2,856	**2,572**	3,719

During the fourth quarter our production increased by 448 boe/d whereas for the year to date it decreased by 1,147 boe/d compared to the same periods of 2018. All reported periods were effected by production restrictions. Since being repaired in November 2018 following a rupture, Enbridge had operated its natural gas T-South Pipelines (“T-South Pipelines”) at reduced pressures which had limited throughput capacity. After a year since being repaired, starting on November 1, 2019, Enbridge began to increase these pipelines’ maximum operating pressures and associated capacities where they were returned to full service on December 1, 2019. Because take away volumes were previously limited from BC, it had an unfavorable effect on the year to date BC Station 2 benchmark price. To limit natural gas volumes previously sold at this benchmark, we voluntarily restricted our production throughout the majority of the year to date except to fulfill, when we could, contracts benchmarked to either the Chicago City Gate or Alliance Trading Pool (“ATP”).

In addition to Enbridge previously operating its T-South Pipelines at reduced operating pressures, starting on January 2, 2019, there was an unplanned outage at the Enbridge McMahon Gas Plant (“McMahon Plant”) that continued through to January 20, 2019. We began to ramp-up our production on January 23, 2019. This involuntary 20 day restricted period partially prevented us from realizing peak pricing during last winter. In addition, during the second and third quarters there was a combined 33 days of unplanned outages at either the McMahon Plant or on the Alliance Pipeline. When we could not fulfil our contracts benchmarked to either the Chicago City Gate or ATP by delivering our own production because of these various outages, we purchased and sold third party production as respectively reported through the line items take-or-pay expenses and revenues (see “Take-or-Pay”).

The production restriction for the comparative quarter also resulted from the aforementioned T-South Pipelines’ capacity constraints. In addition, the comparative year’s production restriction also resulted from integrity and maintenance issues on a portion of Enbridge’s Oak 16” gathering line (the “Oak Pipeline”). This portion of the Oak Pipeline was permanently replaced during the first quarter. As previously alluded, during the majority of the comparative quarter we voluntarily suspended our production in response to depressed BC Station 2 benchmark pricing attributed to lower operating pressures on the T-South Pipelines. The easing of this restriction during the fourth quarter resulted in higher production volumes compared to the same quarter of 2018.

Our fourth quarter production volumes increased 46% compared to the 1,048 boe/d reported during the third quarter. Again, as already alluded, the third quarter was affected by voluntary restrictions to limit natural gas volumes sold at depressed BC Station 2 benchmark pricing. Since November 6, 2019, and throughout the remainder of the fourth quarter, our production averaged 3,770 boe/d. Compared to the overall fourth quarter production of 3,304 boe/d, this increase was in response to the BC Station 2 benchmark’s recovery caused by both higher seasonal pricing and higher industry throughput capacity on Enbridge’s T-South Pipelines. This also contributed to the fourth quarter increase of production compared to the third quarter.

Petroleum and Natural Gas Revenues and Realized Pricing

	Three months ended December 31		Year ended December 31	
($ thousands, except per unit amounts)	**2019**	2018	**2019**	2018
Natural gas liquids sales	**$ 2,030**	$ 1,621	**$ 6,272**	$ 12,354
$/boe	**39.75**	43.56	**42.26**	59.87
Natural gas sales	**$ 2,979**	$ 3,504	**$ 7,969**	$ 13,103
$/mcf	**1.97**	2.60	**1.69**	1.91
Oil sales	**$ 24**	$ 58	**$ 153**	$ 490
$/bbl	**62.11**	54.13	**61.48**	69.15
Petroleum & natural gas revenue	**$ 5,033**	$ 5,183	**$ 14,394**	$ 25,947
$/boe	**16.55**	19.72	**15.33**	19.11

Our petroleum and natural gas revenue for the current reporting periods decreased compared to the same periods of 2018. These decreases are because of lower overall realized pricing caused by a variety of reasons. These reasons, as further elaborated throughout this MD&A, include various lower benchmarks. Also contributing to the year to date decrease was lower production volumes, incurring higher pipeline tariffs to obtain additional take away capacity to minimize our exposure to the BC Station 2 benchmark and being partially unable to realize peak pricing during last winter caused by the previously discussed unplanned outage at the McMahon Plant.

Our average commodity price during the fourth quarter increased 60% from the $10.34/boe realized during the third quarter. This increase was due to various higher benchmarks but especially the recovery in the BC Station 2 benchmark that increased 103% from the $0.97/mcf reported during the third quarter.

Our current reporting periods' realized natural gas pricing were supported by our efforts to limit exposure to the BC Station 2 benchmark through voluntarily restricting production and finding take away capacity at various other benchmarks, albeit with higher associated pipeline tariffs. Through these combined efforts we continue to realize a premium relative to this benchmark.

Benchmark Prices

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Natural gas liquids				
West Texas Intermediate (US$/bbl)	**$ 56.96**	$ 58.81	**$ 57.03**	$ 64.77
Natural gas				
BC Westcoast Station 2 (1) ($/mcf)	**$ 1.49**	$ 0.67	**$ 1.02**	$ 1.25
Alliance Trading Pool (2) ($/GJ)	**$ 1.92**	$ 2.60	**$ 1.66**	$ 2.08
Chicago City Gate (3) (US$/mcf)	**$ 2.44**	$ 3.63	**$ 2.56**	$ 3.06

(1) Market point for BC natural gas.
(2) Market point on the Alliance Pipeline.
(3) Market point for mid-Eastern United States natural gas.

Natural Gas Liquids ("NGL") Pricing

During the current reporting periods, consistent with the directional change in the West Texas Intermediate ("WTI") benchmark, our realized NGL pricing of $39.75/boe and $42.26/boe decreased compared to the same periods of 2018. Our NGL price is a blend of prices received for a range of liquids from propane 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 WTI. The ratio of our NGL price relative to WTI decreased to 53% and 56% for the current reporting periods from 56% and 71% for the same periods of 2018. These lower ratios were due to our NGL annual pricing contracts signed in the spring of 2019 which then included the effect of various lower liquid benchmark pricing. At that time, these lower benchmarks were attributed to a variety of reasons including an increase in supply from both Montney and other Western Canadian shale play producers, a lack of take-away capacity perpetuated by rail shippers focusing on longer-term crude oil contracts and a lower demand from bitumen producers whose own production was curtailed starting January 1, 2019, due to the Government of Alberta imposing mandatory production curtailments in response to a widening Canadian to WTI crude oil benchmark differential.

Our realized NGL price increased 12% during the fourth quarter compared to the $35.58/boe realized price reported during the third quarter. This increase is due to higher propane through to condensate benchmark pricing.

Natural Gas Pricing

Our realized natural gas prices during the current reporting periods decreased compared to the same periods of 2018. These decreases were due to lower Chicago City Gate benchmark pricing in addition to higher pipeline tariffs for additional take away capacity priced to limit exposure to the BC Station 2 benchmark. Also contributing to the year to date decrease was a lower BC Station 2 benchmark and being partially unable to realize peak pricing during last winter's season caused by the previously discussed unplanned outage at the McMahon Plant.

We have firm pipeline capacity benchmarked to the Chicago City Gate of approximately 5,425 GJ/d through to October 31, 2020, with our option to extend the term. Although our additional firm and fixed price contracts have since expired, for the year to date it resulted in further natural gas production being sold at Chicago City Gate and ATP benchmarks and fixed prices ranging from $1.45/GJ to $1.65/GJ, albeit with higher associated pipeline tolls. As a result of these efforts, we sold 56% of our natural gas production during the year to date at prices other than the BC Station 2 benchmark compared to 35% during the same period of 2018. Selling our natural gas production at either fixed prices or these various other benchmarks resulted in us realizing a premium compared to BC Station 2 pricing. Although during both the fourth and comparative quarters we voluntarily restricted our natural gas production to limit exposure to the BC Station 2 benchmark, this restriction was eased commencing on November 6, 2019 when this benchmark began to recover for reasons already discussed. This resulted in a higher ratio of natural gas production sold at the BC Station 2 benchmark during the fourth quarter compared to the same quarter of 2018.

Our realized natural gas price increased 103% during the fourth quarter compared to the $0.97/mcf realized natural gas price reported during the third quarter. This increase was largely due to a higher BC Station 2 benchmark caused by a return to maximum operating pressures and associated capacities on the T-South Pipelines that took more BC natural gas production out of province. Also contributing to the higher fourth quarter natural gas price were seasonal pricing increases in the Chicago City Gate benchmark which then averaged US$2.03/mcf.

Royalties

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Royalty expense	**$ 47**	$ 37	**$ 103**	$ 110
Per sales ($/boe)	**$ 0.16**	$ 0.14	**$ 0.11**	$ 0.08
Percent of revenues (%)	**1**	1	**1**	-

We are reporting negligible royalties for all reported periods. During a previously reported year, we were granted royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). We have continued to receive additional credits since this initial grant including a further grant during the second quarter for $0.2 million. This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. Because our production has been restricted due to depressed BC Station 2 pricing during the year to date, we only recognized $0.3 million of these credits through a decrease to our royalties compared to $0.9 million during the same period of 2018. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program. The 12 (10.47 net) Birley/Umbach wells that have qualified for this credit program bear a minimum crown royalty rate of 6% prior to applying the credits from the Infrastructure Program. Through 2020 we are forecasting nominal BC crown royalties as a result of these credit programs. Overriding and freehold royalties will continue to be payable.

Financial Commodity Price Contracts

To help mitigate commodity price risk, we can enter into financial commodity price contracts which assist us to manage 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 production. While these financial contracts may have opportunity costs when commodity benchmarks exceed the contracted prices, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. We continuously review the need or requirement to utilize financial contracts.

Outstanding commodity price contracts are measured at their approximated fair value on the date of the financial statements. This estimated fair value is 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 dates are recognized as unrealized gains or losses on commodity price contracts whereas realized gains or losses are recognized over their contractual term.

For the reported periods, we had the following realized and unrealized gains or losses from commodity price contracts:

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Realized (gain) loss on commodity price contracts	**$ (41)**	$ 680	**$ 604**	$ 982
Unrealized loss (gain) on commodity price contracts	**15**	(703)	**(235)**	235
(Gain) loss on commodity price contracts	**$ (26)**	$ (23)	**$ 369**	$ 1,217
Realized (gain) loss on commodity price contract ($/boe)	**$ (0.14)**	$ 2.59	**$ 0.64**	$ 0.72

During the fourth quarter we realized a modest gain on commodity price contracts from a natural gas swap that secured the price we received for a portion of our natural gas production because our contracted price of $1.645/GJ was higher than the Westcoast Station 2 benchmark. This gain was partially offset by a natural gas differential swap because our contracted price of NYMEX less US$0.125/mmbtu was lower than the Chicago City Gate benchmark. Both of these contracts expired at the end of the fourth quarter. Similar natural gas differential swaps that had previously expired also contributed to the realized loss during the year to date. Further contributing to the realized losses during the year to date and its comparative period was a Chicago City Gate price indexed contract, which expired at the end of the first quarter, because the contracted price of US$2.68/mmbtu was lower than this benchmark's average price. If we had included these realized gains/losses in our natural gas revenues, we would have reported adjusted natural gas sale prices for the current reporting periods of $1.99/mcf and $1.56/mcf compared to our reported prices of $1.97/mcf and $1.69/mcf.

Outstanding Commodity Price Contracts

As at December 31, 2019, our outstanding commodity price contracts had the following terms:

Contractual Term	Notional Volumes	Index and Company's Received Price
Natural gas swap		
January 1, 2020 to March 31, 2020	2,000 GJ/d	Westcoast Station 2 CAD$1.785/GJ
Natural gas collars		
January 1, 2020 to March 31, 2020	4,000 mmbtu/d	Chicago City Gate Monthly US$2.15/mmbtu to US$4.11/mmbtu

Mark-to-Market

At December 31, 2019, our natural gas commodity price contracts were in a $nil fair value position because the forward BC Station 2 and Chicago City Gate benchmarks approximate our contracted price or are within our collar's price range.

Net Production Expense

($ thousands, except where noted)	Three months ended December 31 2019	2018	Year ended December 31 2019	2018
Production & operating	**$ 3,563**	$ 3,959	**$ 13,001**	$ 16,845
Less:				
Processing & gathering revenues [1]	**(606)**	(276)	**(1,457)**	(1,050)
Net production expense [2]	**$ 2,957**	$ 3,683	**$ 11,544**	$ 15,795
Net production expense ($/boe) [2]	**$ 9.73**	$ 14.01	**$ 12.30**	$ 11.63
Production expense ($/boe)	**$ 11.72**	$ 15.06	**$ 13.85**	$ 12.41

(1) Processing & gathering revenues are included in the line item other revenues as found on the condensed consolidated statements of operations and comprehensive loss.

(2) 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 overall production & operating expense decreased during the current reporting periods compared to the same periods of 2018. The decrease for the year to date was because of production restrictions caused by various third party outages or our reaction to depressed BC Station 2 benchmark pricing. For the same reasons, production expense on a boe basis increased over this same period. This is because all of the production restrictions had the effect of increasing fixed operating costs, on a boe basis, relative to total operating costs. Unavoidable fixed costs can be significant and include, for example, contract operating fees, BC carbon taxes, operating insurance, municipal property taxes, firm processing tolls, mineral and surface lease costs. Although both reported quarters were also affected by voluntary production restrictions, the decrease in the overall production & operating expenses between these quarters was due to the fourth quarter's absence of the comparative quarter's Oak Pipeline integrity and maintenance issues and higher labour and steamer costs to flow restricted volumes through last winter's extremely cold weather. These higher costs could have been avoided had our production been unimpeded. The combination of higher production volumes and a lower overall production & operating expense during the fourth quarter, compared to the same quarter in 2018, resulted in the production expense on a boe basis decreasing by $3.34/boe. Once the fourth quarter's voluntary production restrictions were eased on November 6, 2019, our Birley/Umbach property's average production expense was estimated at $8.31/boe as compared to the corporate production expense during the fourth quarter of $11.72/boe.

During the second quarter we negotiated an agreement to continue to have our natural gas processed at the McMahon Plant. In addition, during the third quarter we also negotiated an incremental McMahon Plant agreement. These contracts expire May and April 2020, respectively. When combined, these contracts allow us to increase our raw natural gas throughput to 23 mmcf/d.

The majority of our processing & gathering revenues come from tolls applied to a customer's production that flows through our 12" Aitken Creek Pipeline which is directly connected to the Alliance Pipeline. This customer's throughput increased during the fourth quarter causing an increase in this type of revenue during the current reporting periods compared to the same periods of 2018. Our Aitken Creek Pipeline commences at Martin Creek and then passes through our Birley lands. It provides us with optionality upon the future development of a gas plant to flow directly to the Alliance Pipeline with access to the Chicago market, BC Station 2 via Enbridge's T-North Pipeline or connect to the recently expanded and now operational TCPL North Montney Mainline. Additionally, during the year to date we completed another transportation agreement for the partial use of our Aitken Creek Pipeline. The agreement commenced in late February 2020 on the initial delivery of gas, and will continue for a minimum period of two years. Additional annualized gathering charges are at least $1.6 million.

Operating Netback

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

	Three months ended December 31		Year ended December 31	
Per sales ($/boe)	**2019**	2018	**2019**	2018
Average commodity pricing	**$ 16.55**	$ 19.72	**$ 15.33**	$ 19.11
Royalty expense	**(0.16)**	(0.14)	**(0.11)**	(0.08)
Realized gain (loss) on commodity price contracts	**0.14**	(2.59)	**(0.64)**	(0.72)
Net production expense [1]	**(9.73)**	(14.01)	**(12.30)**	(11.63)
Operating netback [1]	**$ 6.80**	$ 2.98	**$ 2.28**	$ 6.68

(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.

Despite lower realized commodity pricing, our operating netback increased during the fourth quarter compared to the same quarter of 2018. Although production was initially voluntarily restricted, BC Station 2 pricing recovered in early November 2019 allowing us to produce at unrestricted volumes for the remainder of the fourth quarter. This increase in production volumes had the effect of decreasing fixed operating costs, on a boe basis, relative to total operating quarters. There was also the absence of a realized loss on commodity price contracts that we had previously reported during the comparative quarter. Inversely, our operating netback decreased during the year to date compared to the same period of 2018. Given the extent of restrictions to limit our production sold at depressed BC Station 2 pricing, in addition to third party outages, the year to date operating netback is not representative of the profitability of our operations. These restrictions largely limited production to levels required by our firm pipeline capacity and processing contracts. Also contributing to these netback decreases were lower average liquid prices caused by our annual pricing contracts signed in the spring of 2019 and higher realized losses from commodity price contracts that have since expired.

Take-or-Pay

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Take-or-pay revenues [1]	**$ (608)**	$ (801)	**$ (3,053)**	$ (3,821)
Take-or-pay expense	**$ 665**	$ 945	**$ 4,005**	$ 4,389

(1) Take-or-pay revenues are included in the line item *other revenues* as found on the consolidated statements of operations and comprehensive loss.

Included in both take-or-pay contract revenues and expenses for the year to date are the following cost mitigation programs:

- The revenue and expense of selling and purchasing, respectively, third party natural gas production to meet our firm volume commitments on various third party pipelines was necessitated by the outages at either the McMahon Plant or on the Alliance Pipeline. Although we benefited from the purchase and sale of these third party volumes, the net cost after including the associated pipeline tariffs during the year to date was $0.4 million. Although we cannot say with any certainty, we do not anticipate future cost mitigation programs to be significant.
- The revenue and expense of selling and purchasing, respectively, third party NGL production was necessitated to meet a take-or-pay processing agreement. The $0.6 million net cost during the year to date compares to the same period of 2018 although take-or-pay contracts' revenues and expenses have both decreased because of lower firm commitments and a reduction in NGL pricing. We have partially mitigated our continued exposure to this fee at least through to the first quarter of 2020 under similar terms as previously reported. The take or pay processing agreement has one further lower annual firm commitment through to its expiry on March 31, 2021.

General & Administrative ("G&A") Expense

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
G&A expense before recoveries	**$ 947**	$ 1,375	**$ 3,994**	$ 5,862
Recoveries	**(248)**	(356)	**(1,078)**	(1,748)
G&A expense	**$ 699**	$ 1,019	**$ 2,916**	$ 4,114
Per sales ($/boe)	**$ 2.30**	$ 3.88	**$ 3.11**	$ 3.03

For the current reporting periods, we realized lower G&A expenses before recoveries including lower staffing costs due to last year's 40% headcount reduction, the suspension of an employee benefit program and reduced information system costs. We have also implemented a reduced work week since May 2019, where relative to 2018 this was implemented only through the summer months.

During the second quarter we signed a lease for our current Calgary office space that commenced on June 1, 2019 with an initial expiry of August 31, 2022 but with our option to extend, under the same terms, to February 28, 2025. The estimated annual cash savings from this new lease are $2.0 million.

On January 1, 2019, we adopted *IFRS 16, Leases* ("IFRS 16") (see "Adopted New Accounting Standard"). This new accounting standard resulted in office rents of $1.4 million for the year to date, which includes lease and non-lease components, being respectively reported as reductions of $0.2 million and $0.6 million in our prepaids (see "Adopted New Accounting Standard") and lease liabilities (see "Lease Liabilities"), respectively, and a charge of $0.6 million to G&A expense before recoveries. Included in the same period of 2018 are $2.4 million of office rents but reported as a charge of $1.6 million to G&A expense before recoveries and a $0.8 million reduction in our onerous contract provision. Excluding the effect of lower office rents which saved us $1.0 million during the year to date compared to the same period of 2018, as a result of adopting IFRS 16, G&A expense before recoveries decreased $0.4 million during the year to date.

Partially offsetting the above decreases to G&A expense before recoveries were lower G&A recoveries. With lower compensation costs combined with reduced capital and production & operating costs, our capitalized G&A, capital and other associated G&A recoveries decreased by $0.1 million and $0.7 million during the current reporting periods compared to the same periods of 2018.

G&A on a boe basis decreased during the fourth quarter compared to the same quarter of 2018 because of the aforementioned cost reductions combined with higher production volumes. Whereas G&A on a boe basis increased during the year to date compared to the same period of 2018, despite decreases in overall G&A, as a result of lower production.

Financing

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Accretion of decommissioning obligations	**$ 146**	$ 157	**$ 638**	$ 680
Interest on bank debt	**141**	35	**295**	109
Other	**6**	6	**38**	84
Financing	**$ 293**	$ 198	**$ 971**	$ 873

Our effective interest rates on bank debt were 7.5% and 5.3% during the current reporting periods compared to 4.9% and 4.6% for the same periods of 2018. Excluding the effect from these interest rate changes, the increase in the current reporting periods' interest on bank debt compared to the same periods in 2018 was due to higher average drawn debt.

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see "Adopted New Accounting Standard"). Interest expense from lease liabilities included in our other financing costs during the current reporting periods was insignificant.

The accretion charges during the current reporting periods are modestly lower compared to the same periods of 2018 because during the second quarter we lowered the applied decommissioning obligations' risk-free discount rate from 2.1% to 1.7%. Effective January 1, 2020, we decreased our estimated decommissioning obligations' risk-free discount rate to 1.8%.

Other Losses

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Other losses	**$ 58**	$ 65	**$ 188**	$ 149

Other losses during the reported periods were mostly in respect of exploratory mineral and surface rental costs.

Impairment of Development & Production and Exploration & Evaluation Assets

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Impairment of development & production and exploration & evaluation assets	**$ 13,293**	$ 19,600	**$ 32,193**	$ 19,600

We initially identified evidence indicating impairment in the June 30, 2019 carrying values of our development & production assets. This evidence was a significant sustained reduction in forward British Columbia Station 2 natural gas pricing. Further evidence indicating impairment in the June 30, 2019 carrying value of producing properties were concerns about our ability to finance our future development costs and the timing thereof. As a result, we tested for impairment on our one remaining *Peace River Arch* CGU. The CGU's recoverable value was estimated using a value-in-use calculation based on a roll forward of the December 31, 2018 independently prepared reserve report adjusted by management for the three engineering firms' average July 1, 2019 price forecasts, reserves produced during the first six months ended June 30, 2019 and deferring future development costs. 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 ranging from 10% to 20% depending on the reserve category. This test revealed impairment of $18.9 million as originally reported during the second quarter.

We identified further evidence indicating impairment in the December 31, 2019 carrying values of our development & production and exploration & evaluation assets. This evidence was the execution of the Arrangement Agreement where the associated consideration of $0.0675 per common share (the "Share Consideration") was less than our equivalent per common share book amount. As a result of the Arrangement Agreement, the recoverable value of both our producing and exploratory properties was determined from their combined fair value less costs to sell which also approximates a value-in-use measure because our intention is now to sell the company. As at June 30, 2019 and December 31, 2018, our producing properties recoverable value was measured using a value-in-use model partially because the intended use at that time was to continue operations.

The combined net carrying amount prior to recognizing any further impairment as at December 31, 2019 of our producing and exploratory properties less decommissioning obligations was $36.1 million. This net carrying amount was then compared to the proceeds pursuant to the Arrangement Agreement as detailed as follows:

- $15.1 million as determined from the Share Consideration of $0.0675 per common share times the 223.7 million outstanding common shares; and
- Estimated net debt, as defined by the Arrangement Agreement.

These combined proceeds, which approximates the fair value of the Transaction on its estimated closing date in late April 2020, is after forecasted costs to sell which have been assumed by the Purchaser. The estimated fair value less costs to sell at April 2020 was then used to determine the equivalent measure at December 31, 2019. The total consideration to be paid to our shareholders plus estimated net debt and cash flow growth through to the closing of the Transaction is estimated to be $22.8 million. Because the combined net carrying amount exceeded the fair value less costs to sell, this resulted in a fourth quarter impairment charge totalling $13.3 million.

Including the recognized impairment of $18.9 million as originally reported during the second quarter, the combined year to date impairment was $32.2 million ($19.6 million for the comparative periods).

No impairment expense sensitivity analysis has been provided as the fair value less costs to sell was contractually determined.

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

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Depletion, depreciation & amortization	**$ 2,404**	$ 2,367	**$ 8,390**	$ 11,654
Depletion per sales ($/boe)	**$ 6.51**	$ 7.51	**$ 6.70**	$ 7.36

Lower production volumes and depletion rates resulted in depletion expense being $3.7 million lower during the year to date compared to the same period of 2018. Inversely, higher production volumes, despite lower depletion rates, resulted in depletion expense being modestly higher during the fourth quarter compared to the same quarter of 2018. These lower depletion rates were due to both the second quarter and previous year's impairment expenses of $18.9 million and $19.6 million, respectively, that each lowered the net carrying value of our development & production assets combined with a modest increase in the December 31, 2018 measure of our proved plus probable reserves.

As previously discussed, on January 1, 2019, we adopted IFRS 16 (see "Adopted New Accounting Standard"). During the year to date this new accounting standard resulted in us reporting additional depreciation of $0.4 million against right-of-use assets. As we adopted this new accounting standard using a modified retrospective approach, there is no comparable depreciation expense in the same period of 2018. This partially offset the effects from lower production volumes and depletion rates, as previously discussed, that resulted in a decrease to the overall DD&A expense during the year to date compared to the same period of 2018.

Deferred Customer Obligation Amortization

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Deferred customer obligation amortization	**$ (194)**	$ (194)	**$ (777)**	$ (777)

During a previously reported year, a customer transferred a section of pipeline to us which connected our 12" Aitken Creek Pipeline, located in northeast BC, to the Alliance Pipeline. The estimated fair value of this connecting pipeline resulted in a deferred customer obligation which is being 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 our Aitken Creek Pipeline.

Indemnification Provision Change in Estimate

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Indemnification provision change in estimate	**$ (660)**	$ -	**$ (660)**	$ -

We are involved in litigation and claims arising from indemnifications provided to the buyer of our former Tunisian operations (see "Provisions") that are attributable to years prior to 2014. During the current reporting periods, the Tunisian Appellant Court ruled on a claim initiated by a previous Tunisian service provider. This ruling was lower than what we had previously measured and resulted in a decrease to our indemnification provision reported as a $0.7 million change in estimate with no associated expenditure.

Share-Based Compensation

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Share-based compensation	**$ 104**	$ 149	**$ 468**	$ 508

The number of share-based awards granted during the year to date decreased compared to the same period of 2018. When combined with each granted share-based award having a lower estimated fair value, this resulted in decreases of share-based compensation for the current reporting periods compared to the same periods of 2018. The lower number of granted share-based awards was attributable to headcount reductions throughout the comparative year whereas each award's lower estimated fair value was due to a decrease in our publically traded share price.

Severance Costs

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Severance costs	**$ -**	$ -	**$ -**	$ 834

Severance costs incurred during the comparative year related to staffing reductions that reduced our headcount by 40% as we assessed our staffing requirements.

Gain on Dispositions of Properties

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Gain on dispositions of properties	**$ -**	$ (721)	**$ -**	$ (721)

During the comparative year, we disposed of mineral rights with associated undeveloped lands, shut-in and suspended wells located in Rigel, British Columbia and Gordondale, Alberta to third parties in consideration for them assuming the decommissioning obligations. There were no reserves associated with these mineral rights. The $0.2 million net carrying amount of the undeveloped lands less $0.9 million of associated decommissioning obligations resulted in a gain on the transfer of properties of $0.7 million.

Amortization of Flow-Through Common Shares Premium

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Amortization of flow-through common shares premium	**$ -**	$ -	**$ -**	$ (323)

During the comparative year, we incurred the required $2.0 million of qualifying Canadian exploration expenditures pursuant to a previous reported year's issuance of 6,450,000 common shares on a flow-through basis. As a result of incurring these exploration expenditures, we amortized the associated $0.3 million flow-through common shares premium.

Income Tax

We have not reported deferred tax assets because it is not probable that we can utilize our tax pools against future taxable profit. We estimate we had the following tax pools at December 31, 2019:

($ thousands)	**December 31 2019**
Canadian oil & gas property expense	**$ 994**
Canadian development expense	**24,630**
Canadian exploration expense	**55,078**
Undepreciated capital costs	**21,158**
Net operating losses	**316,985**
Net capital loss	**10,987**
Other	**1,796**
Total	**$ 431,628**

The Government of Alberta's Bill 3, *Job Creation Tax Cut Act*, received Royal Assent during the second quarter. This reduced the general Alberta corporate tax rate from 12% to 11.5% during 2019 and will further reduce this rate from 10% to 8% from 2020 to 2022. Because our head office is in Calgary whereas our operations are located in northeastern BC, approximately one-half of any future corporate taxable income would be allocated to Alberta with the other half allocated to BC. These reduced tax rates have lowered the value of our unrecognized deferred tax asset and the associated valuation allowance.

Net & Comprehensive Loss

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Weighted average shares outstanding - basic & diluted (thousands)	**223,682**	223,605	**223,672**	223,594
Net & comprehensive loss	**$ (13,998)**	$ (21,141)	**$ (42,263)**	$ (27,654)
Net loss per share - basic & diluted ($/share)	**$ (0.06)**	$ (0.09)	**$ (0.19)**	$ (0.12)

The net loss increased during the year to date compared to the same period of 2018. This increase was due to both lower production volumes and commodity pricing for reasons previously explained. To reiterate, during the year to date the lower commodity pricing includes being partially unable to realize peak pricing during last winter's season caused by the unplanned outage at the McMahon Plant. The associated production restriction was further exacerbated as we had previously entered into incremental short-term firm volume pipeline commitments, with their associated tariffs, to deliver natural gas production at various benchmarks and fixed prices with the objective to limit exposure to the BC Station 2 benchmark. These firm volume pipeline tariffs during the unplanned outage at the McMahon Plant, net of our mitigation efforts, caused an increase in our net take-or-pay cost. Further contributing to the increase in the net loss was impairment of $32.2 million charged against our producing and exploratory assets for the year to date compared to $19.6 million charged against producing assets for the comparative year. The impairment expense for the year to date was due to the Arrangement Agreement (see "Subsequent Events") that provided a contractually determined fair value less costs to sell of our producing and exploratory assets less the associated decommissioning obligation.

The net loss decreased during the fourth quarter compared to the same quarter of 2018. This decrease was due to previously reporting a portion of the year to date impairment charge whereas this same charge was reported in its entirety during the fourth quarter of 2018. Further contributing to this decrease was both higher production volumes and third party throughput on our Aitken Creek Pipeline combined with a favorable change in estimate to our indemnification provision.

Capital Resources and Capital Expenditures

Adjusted Funds Flow (Outflow) & Cash (Outflow) Inflow from Operating Activities

	Three months ended December 31		Year ended December 31	
($ thousands, except where noted)	**2019**	2018	**2019**	2018
Cash (outflow) inflow from operating activities	**$ (48)**	$ (378)	**$ (3,634)**	$ 255
Add (deduct):				
Change in operating non-cash working capital	**913**	(690)	**310**	1,311
Provision expenditures	**249**	595	**1,094**	1,608
Exploration & evaluation expenses (1)	**57**	60	**196**	171
Severance costs	**-**	-	**-**	834
Adjusted funds flow (outflow)(2)	**$ 1,171**	$ (413)	**$ (2,034)**	$ 4,179
Per share - basic & diluted	**$ 0.01**	$ -	**$ (0.01)**	$ 0.02

(1) Exploration & evaluation expenses are included in the line item *other losses* as found on the consolidated statements of operations and comprehensive loss.
(2) 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.

An adjusted funds flow for the fourth quarter increased by $1.6 million, despite lower overall commodity pricing, compared to the outflow during the same quarter of 2018. This increase was due to higher production volumes and lower overall production & operating and G&A expenses, an increase in a third party's volumes through our Aitken Creek Pipeline and modest realized gains on commodity price contracts versus losses on similar contracts during the fourth quarter of 2018. Inversely, adjusted funds for the year to date decreased compared to the same period in 2018. This decrease was due to both lower production volumes and commodity pricing and increases in the take-or-pay net expense. Further contributing to the year to date decrease was higher realized losses from commodity price contracts. These year to date effects were partially offset by lower overall production & operating and G&A expenses.

For the same reasons as just explained for adjusted funds flow, cash flows from operating activities changed during the current reporting periods compared to the same periods of 2018. The cash outflow from operating activities for the year to date benefited from both a decrease in provision expenditures and the absence of severance costs reported during the same period of 2018. Contributing to the year to date decrease in operating non-cash working capital was the return of a $1.0 million deposit that previously guaranteed additional firm volume pipeline capacity, which has since expired, less a $0.5 million deposit we recently posted to guarantee future processing tolls through the McMahon Plant.

Capital Expenditures

Our development and exploration expenditures and proceeds from a disposition during the reported periods were as follows:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2019**	2018	**2019**	2018
Proceeds from a disposition	**$ -**	$ -	**$ 33**	$ -
Expenditures				
Land & lease	**$ -**	$ 88	**$ -**	$ 262
Drilling & completions	**-**	125	**-**	2,225
Facilities & equipment	**-**	-	**-**	253
Field expenditures	**-**	213	**-**	2,740
Right-of-use asset	**-**	-	**29**	-
Capitalized G&A	**-**	-	**-**	150
Total expenditures	**$ -**	$ 213	**$ 29**	$ 2,890

Our focus during the current reporting periods, as it continues to be, is capital preservation. As a result, during the current reporting periods we did not incur any capital expenditures. During the comparative year to date, we drilled and completed two (2.0 net) exploratory vertical Birley/Umbach wells. The drilling and completion costs for these two (2.0 net) wells totaled $2.2 million. These wells further delineated 21 gross (20.5 net) undrilled contiguous sections of Montney rights (located three kilometres north of our main Montney land block and eight kilometres from the nearest well drilled into the Montney). These vertical wells, which also preserved undeveloped lands, were funded by the proceeds from a previous reported year's flow-through share issuance. Each well encountered approximately 225 metres of total Montney thickness. The quality of the reservoir encountered, particularly in the top 75 metres of the Montney and as seen from wireline log data, had consistent hydrocarbon charged porosity. Each well was perforated to obtain pressure information. We abandoned these wells which satisfies our flow-through financing obligations.

Disposition of Properties

During the year to date, we sold our mineral rights located in Gordondale, Alberta to a third party. There were $nil million in both proceeds and net carrying amounts associated to this property disposition. There were no wells associated with these mineral rights.

During the comparative reporting periods, we transferred mineral rights located in Rigel, British Columbia and Gordondale, Alberta to third parties in consideration for them assuming the associated decommissioning obligations of suspended and shut-in wells and associated infrastructure.

For the above dispositions, there were no reserves associated with these mineral rights.

Net Debt

($ thousands)	December 31 2019	December 31 2018
Debt	**$ 7,022**	$ 2,361
Accounts receivable	**(3,568)**	(3,386)
Prepaids & deposits	**(1,525)**	(2,528)
Accounts payable & accrued liabilities	**4,209**	5,547
Net debt (1)	**$ 6,138**	$ 1,994

(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 $6.1 million and $2.0 million at December 31, 2019 and December 31, 2018, respectively. Net debt increased between these reported dates because of the year to date adjusted funds outflow of $2.0 million and expenditures of $1.9 million which included both decommissioning obligations and lease payments (see "Adopted New Accounting Standard"). Prepaid rents associated with our previous Calgary office space for $0.2 million was also reclassified as a right-of-use asset on adoption of IFRS 16 (see "Adopted New Accounting Standard"). This resulted in a January 1, 2019 decrease in our non-cash working capital and a corresponding increase in our net debt.

Our ability to discharge our financial liabilities, as included in net debt, and fund our future operations is discussed within this MD&A under the "Future Operations and Liquidity" header.

We normally manage expenditures not to exceed our annual adjusted funds flow. However, during the year to date we incurred $0.9 million of decommissioning obligation expenditures which included abandonments of 2.0 (2.0 net) vertical wells. As previously discussed, these abandonments were necessary in order to satisfy our flow-through financing obligations. For the year to date we are also reporting an adjusted funds outflow because of the various third party outages that partially prevented us from realizing peak pricing during last winter's season in addition to us continuing to incur both firm volume pipeline tolls and fixed production & operating costs in the absence of production combined with voluntary restrictions in response to depressed BC Station 2 pricing.

Credit Facility

Our amended demand credit facility agreement with a Canadian chartered bank had an availability of $10.0 million as at December 31, 2019 and 2018 (the "Demand Credit Facility"). Subsequent to December 31, 2019, our lender completed the borrowing base redetermination. The maximum availability remained unchanged at $10.0 million. This most recent renewal as signed on February 28, 2020 removed the minimum hedging requirement that previously was required as at December 31, 2019 and 2018 in addition to waiving breaches in the net debt to cash flow financial covenant as determined at June 30, September 30 and December 31, 2019 and as forecast for March 31, 2020. The next renewal is scheduled on May 31, 2020 but may be set at an earlier (or later) date at the sole discretion of the lender.

At December 31, 2019, we had debt borrowings of $7.0 million, which included $4.7 million of borrowings drawn during the year to date and undrawn letters of credit of $0.9 million, as secured by our lender, which reduced the available credit to $2.1 million (at December 31, 2018 – drawings of $2.4 million, undrawn letters of credit of $0.9 million and available credit of $6.7 million).

All borrowings under the Demand Credit Facility have always been classified as a current liability, as the lender can request repayment of all outstanding drawn amounts at any time. 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. In addition, the Demand Credit Facility includes operating and financial restrictions on us that include restrictions on paying dividends or making other distributions in respect of our securities.

The Demand Credit Facility has financial covenants requiring that at each reporting period the *adjusted working capital* equals or exceeds a one-to-one ratio and that *net debt to cash flows* (waived for March 31, 2020) does not exceed a three-to-one ratio. Because the lender's definition of cash flows includes lease payments, this measure, was unaffected by adopting IFRS 16 (see "Adopted New Accounting Standard"). For the purposes of these covenants:

- *Adjusted working capital* is defined as working capital excluding both the current portion of commodity price contracts and debt but including the undrawn portion of the Demand Credit Facility,
- *Net debt* is defined as working capital but excluding the current portion of commodity price contracts, and
- *Cash flows* are determined over the last 12 months and are defined as cash flows from operating activities before changes in non-cash working capital less lease payments.

The February 28, 2020 renewal also has additional reporting requirements including weekly forecasted cash flows and monthly abandonment and reclamation activities in addition to requiring that the minimum LMR does not fall below 1.3 as determined for us by the BCOGC.

Although we recently received waivers for past financial covenant breaches and a forecasted breach, we are further forecasting to be in breach of the *net debt to cash flow* financial covenant per the terms of the renewed demand credit facility agreement as at June 30, 2020 assuming average realized natural gas and natural gas liquids' pricing of $1.86/mcf and $41.76/bbl, respectively. In the event that the Transaction is not competed, when the next borrowing base redetermination commences as scheduled on (or before or later) May 31, 2020, because of the forecasted breach, no assurance can be provided that the borrowing base will be renewed at the same or a similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of this forecasted breach or for any other reason.

Lease Liabilities

On adoption of IFRS 16 (see "Adopted New Accounting Standard") we recognized $0.6 million of lease liabilities that mostly consist of our previous Calgary head office space. Although there was an available optional short-term expedient because this lease expired in June 2019, we chose not to take this option because our current Calgary office space and its associated payments are also captured under IFRS 16. The effect of discounting this liability at our incremental borrowing rate, estimated at 6% and 7.8% on adoption and at December 31, 2019, respectively, was insignificant because of the magnitude of this liability. Lease payments during the year to date totaled $0.6 million. At December 31, 2019, we are reporting $0.2 million of lease liabilities mostly associated with our current Calgary office space.

Provisions

Decommissioning Obligations

At December 31, 2019, the net present value of our decommissioning obligations was $35.8 million which was higher than $32.4 million at December 31, 2018. During the year to date, an increase of $3.3 million in decommissioning obligations was caused by an increase in cost estimates recently released by the BCOGC and accretion which reflects the increase in the obligation associated with the passage of time as partially offset by expenditures and an increase in the risk free rate. We estimate this net present value based on a total future undiscounted and uninflated liability of $37.1 million (December 31, 2018 - $33.3 million).

As at December 31, 2019 and 2018, 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, respective annual inflation rates of 1.5% and 2.0% used to calculate the obligations' future value and respective average risk-free interest rates of 1.8% and 2.1% used to calculate the obligations' present value.

Onerous Contract

On adoption of IFRS 16 (see "Adopted New Accounting Standard"), we applied a practical expedient that allowed us to decrease our previous Calgary office space right-of-use asset by the associated onerous contract provision of $0.4 million last reported at December

31, 2018. As a result, on adoption of IFRS 16 and thereafter we no longer report an onerous contract provision associated with our previous Calgary office space.

Indemnifications

We are also involved in litigation and claims arising from indemnifications provided to the buyer of our wholly-owned subsidiary's former Tunisian operations that are attributable to years prior to 2014. During the current reporting periods, the Tunisian Appellant Court ruled on a claim initiated by a previous Tunisian service provider. This ruling was lower than what we had previously measured and resulted in a decrease to our indemnification provision reported as a $0.7 million change in estimate with no associated expenditure. During the year to date, indemnification provision expenditures associated with defending our interests totaled $0.1 million. Our estimated remaining indemnification provision is $0.1 million as at December 31, 2019.

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 restricted awards are as follows:

	December 31 2019	December 31 2018
Common shares outstanding	**223,682,001**	223,604,601
Share options	**15,475,900**	13,177,200
Restricted awards	**49,900**	127,300
Weighted average common shares - basic and diluted	**223,672,022**	223,594,409

As at March 2, 2020, we had 223,731,901 common shares, 15,020,900 share options and nil restricted awards outstanding.

Commitments and Guarantees

At December 31, 2019, we had the following unrecognized contractual payments without giving effect to any offsetting third party agreements, which are anticipated to reduce some of these amounts:

	2020	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Office contracts	$ 348	$ 320	$ 304	$ 300	$ 301	$ 47	$ 1,620
Operating and transportation contracts	2,338	220	-	-	-	-	2,558
	$ 2,686	**$ 540**	**$ 304**	**$ 300**	**$ 301**	**$ 47**	**$ 4,178**

The office contracts include the non-lease component of our current Calgary office space whereas the operating and transportation contracts relate to minimum contractual payments if we do not benefit from the operating services or pipeline transportation. The latter captures our most recent McMahon Plant processing agreements executed during the second and third quarters that expire on May 31 and April 30, 2020, respectively.

At December 31, 2019 and 2018, we had guaranteed a pipeline commitment through undrawn letters of credit of $0.9 million (see "Future Operations and Liquidity" and "Credit Facility") as secured by our lender. At December 31, 2018, our prepaids and deposits included a payment of $1.2 million to further guarantee this pipeline commitment that was mostly refunded during the year to date.

At December 31, 2019, we have guaranteed future processing tolls through a payment of $0.5 million as included in prepaids and deposits. We have also guaranteed indemnifications provided by our wholly owned subsidiary to the buyer of our former Tunisian operations (see "Indemnifications").

Off Balance Sheet Arrangements

We did not enter into any off balance sheet arrangements during the reported 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 share option plan. The officers' salaries, directors' fees and other benefits, as mostly included in G&A expense for the reported and comparable years, totaled $1.2 million and $1.7 million. The share option plan benefits for our officers and directors, as included in share-based compensation for the reported and comparable years, totaled $0.4 million and $0.5 million.

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, we were engaged to manage, administer and maintain the properties and the books, accounts and records of WOGH Limited Partnership ("WOGH"). WOGH 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, we are reimbursed for such services. In accordance with the Services Agreement, we reported a recovery from WOGH, as mostly reported against our G&A expense, of $0.5 million and $0.9 million for the reported and comparable years. The recovery for the reported and comparative years was generally determined from WOGH's pro rata share as estimated at 11% and 12% of its and our combined production volumes. At December 31, 2019 and 2018, $nil million and $0.1 million, respectively, of this G&A recovery was included in accounts receivable.

Selected Annual Information

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

Year ended December 31		**2019**		**2018**		**2017**
($ thousands, except per share amounts)						
Petroleum & natural gas revenue, net of royalties	**$**	**14,291**	$	25,837	$	21,271
Net loss [(1)]	**$**	**(42,263)**	$	(27,654)	$	(16,914)
Per share - basic & diluted ($/share)	**$**	**(0.19)**	$	(0.12)	$	(0.08)
Total assets	**$**	**63,797**	$	101,416	$	130,571
Long-term liabilities [(2)]	**$**	**35,770**	$	33,794	$	33,377

(1) Includes $32.2 million, $19.6 million and $17.1 million of impairment charges for the years ended December 31, 2019, 2018 and 2017, respectively.
(2) Includes provisions and other long-term liabilities.

Petroleum & natural gas revenues, net of royalties increased from 2017 to 2018 but then decreased from 2018 to the reported year. The increase during 2018, compared to 2017, was due to higher liquid benchmark pricing and a modest increase in volumes resulting from our 2016 and 2017 Montney drilling programs at our Birley/Umbach area which added seven (6.27 net) horizontal wells. As previously explained, the reported year's volumes were negatively affected by a combination of third party and voluntary restrictions where the latter originated from the rupture of one of the T-South Pipelines resulting in both pipelines subsequently being operated at reduced pressures and the associated effect on depressing the BC Station 2 benchmark. The reported year's lower realized liquid price, compared to 2018, resulted from a precipitous decrease in the Canadian light sweet crude oil benchmark. The combination of the aforementioned resulted in the reported year's decrease in petroleum & natural gas revenue, net of royalties, compared to 2018.

The net losses for each of the above successive years largely resulted from impairment charges caused by sustained decreases in forward BC Station 2 benchmark pricing. These impairment charges combined with DD&A contributed to each consecutive year's decrease in total assets.

The increase in long-term liabilities from 2017 to 2018 was caused by the latter year's higher estimated decommissioning obligations caused by both a decrease in the risk free rate and the associated obligations from drilling and completing two (2.0 net) exploratory vertical Birley/Umbach wells on our north Montney block. The increase in long-term liabilities from 2018 to the reported year was due to the latter year's higher cost estimates included in our decommissioning obligations' measure that were recently released by the BCOGC.

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

Quarterly Information from Operations

Summarized information by quarter for the two years ended December 31, 2019, appears below:

	Dec. 31 2019	Sept. 30 2019	Jun. 30 2019	Mar. 31 2019	Dec. 31 2018	Sept. 30 2018	Jun. 30 2018	Mar. 31 2018
Production Volumes								
Natural gas liquids (boe/d)	**555**	337	279	455	405	707	680	468
Natural gas (mcf/d)	**16,469**	11,488	8,457	15,389	14,641	24,454	22,253	13,806
Crude oil (bbl/d)	**4**	5	10	9	12	24	23	19
Average daily production (boe/d)	**3,304**	2,256	1,698	3,029	2,856	4,807	4,413	2,788
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 39.75**	$ 35.58	$ 43.02	$ 49.96	$ 43.56	$ 63.73	$ 66.65	$ 58.35
Average natural gas price ($/mcf)	**$ 1.97**	$ 0.97	$ 1.38	$ 2.10	$ 2.60	$ 1.54	$ 1.40	$ 2.64
Average oil price ($/bbl)	**$ 62.11**	$ 55.63	$ 67.20	$ 57.89	$ 54.13	$ 71.35	$ 75.11	$ 68.34
Operating Netback(1)								
Average commodity pricing ($/boe)	**$ 16.55**	$ 10.34	$ 14.33	$ 18.34	$ 19.72	$ 17.59	$ 17.75	$ 23.35
Royalty expense ($/boe)	**$ (0.16)**	$ (0.05)	$ (0.22)	$ (0.04)	$ (0.14)	$ -	$ (0.07)	$ (0.17)
Realized gain (loss) on derivative contracts ($/boe)	**$ 0.14**	$ (0.24)	$ (0.89)	$ (1.69)	$ (2.59)	$ (0.17)	$ 0.17	$ (1.18)
Net production expenses ($/boe)(1)	**$ (9.73)**	$ (13.70)	$ (17.26)	$ (11.28)	$ (14.01)	$ (9.74)	$ (10.17)	$ (14.84)
Operating netback ($/boe)(1)(2)	**$ 6.80**	$ (3.65)	$ (4.04)	$ 5.33	$ 2.98	$ 7.68	$ 7.68	$ 7.16
Wells Drilled								
Exploratory wells (net)	**-**	-	-	-	-	-	-	2.00
Natural gas wells (net)	**-**	-	-	-	-	-	-	-
FINANCIAL ($ thousands, except per share amounts)								
Petroleum & natural gas revenues, net of royalties	**$ 4,986**	$ 2,136	$ 2,178	$ 4,991	$ 5,146	$ 7,778	$ 7,098	$ 5,815
Adjusted funds flow (outflow)(1)	**$ 1,171**	$ (1,691)	$ (1,708)	$ 194	$ (413)	$ 2,285	$ 1,836	$ 471
Per share - basic & diluted ($/share)	**$ 0.01**	$ (0.01)	$ (0.01)	$ -	$ -	$ 0.01	$ 0.01	$ -
Cash (outflow) inflow from operating activities	**$ (48)**	$ (1,489)	$ (1,940)	$ (157)	$ (378)	$ 1,132	$ 1,223	$ (1,722)
Net loss (3)	**$ (13,998)**	$ (3,527)	$ (22,242)	$ (2,496)	$ (21,141)	$ (1,944)	$ (2,471)	$ (2,098)
Per share - basic & diluted ($/share)	**$ (0.06)**	$ (0.02)	$ (0.10)	$ (0.01)	$ (0.09)	$ (0.01)	$ (0.01)	$ (0.01)
Development and exploration expenditures	**$ -**	$ -	$ -	$ -	$ 213	$ -	$ 180	$ 2,497
Net debt (1)	**$ 6,138**	$ 6,982	$ 5,207	$ 3,120	$ 1,994	$ 713	$ 2,654	$ 3,961
Total assets	**$ 63,797**	$ 75,920	$ 77,284	$ 97,022	$ 101,416	$ 120,572	$ 123,637	$ 127,227
Common Shares (thousands)								
Weighted average during period								
Basic and diluted	**223,682**	223,682	223,681	223,642	223,605	223,605	223,603	223,565
Outstanding at period end	**223,682**	223,682	223,682	223,655	223,605	223,605	223,605	223,565

(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) May not be additive due to rounding.

(3) Includes $13.3 million, $18.9 million and $19.6 million in impairment charges against properties for the three months ended December 31, 2019, June 30, 2019 and December 31, 2018, respectively.

Factors That Have Caused Variations over the Quarters

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

Since our transition to a Montney play focused company, production trended with our Birley/Umbach property including this area’s 2016 and 2017 development programs which added seven (6.27 net) horizontal wells, of which the remaining two (2.00 net) wells came on-stream during the first quarter of 2018. However, other than the second and third quarters of 2018, extended third party restrictions did not allow us to demonstrate our production potential. Production since the third quarter of 2018 was also affected by the rupture on one of the T-South Pipelines. We then reacted to the resulting depressed BC Station 2 benchmark pricing by voluntarily shutting-in our production.

Changes in our petroleum and natural gas revenues, net of royalties and adjusted funds flow have trended with volumes and the BC Station 2 and WTI benchmark prices. The previously described volume changes can shift the weighting of our natural gas production away from BC Station 2 and towards Chicago City Gate benchmark pricing or vice versa. Since the first quarter of 2018, we acted to preserve capital given depressed and volatile BC Station 2 pricing. Since the third quarter of 2018, our production has been restricted either due to third party constraints or voluntarily in reaction to depressed BC Station 2 pricing. As a result, through to the third quarter we reported nominal or adjusted funds outflows and correspondingly higher net debt. This trend was interrupted during the fourth quarter as peak winter natural gas pricing combined with the T-South Pipelines returning to full operating capacities resulted in a recovery of the BC Station 2 benchmark. This eased our past production restrictions resulting in the fourth quarter's increase to our adjusted funds flow and correspondingly lowering our net debt.

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

Additional information on risks, assumptions and uncertainties are found under the heading "Forward-Looking Statements". The following are the two most significant risk factors as copied from our AIF:

The Transaction to Sell our Company to the Purchaser May Not Be Completed

The Transaction is subject to various closing conditions, including receipt of Court approval and shareholder approval. Further details on the conditions precedent to the completion of the Transaction are set forth in the Arrangement Agreement which is filed on our SEDAR profile at www.sedar.com. The Transaction may not be completed on the terms contemplated by the Arrangement Agreement or at all due to failure to obtain the receipt of the necessary Court and shareholder approvals or failure to satisfy the other conditions precedent to the closing of the Transaction. There are no assurances that the Transaction will be completed. In addition, the Arrangement Agreement provides for a non-completion fee of $1.75 million in the event that the Transaction is not completed or is terminated by us in certain circumstances, including if we enter into an agreement with respect to a superior proposal or if our Board withdraws or modifies its recommendation with respect to the Transaction.

An additional risk factor in the event that the Transaction is not completed, is that we are forecasting that we will be in breach as at June 30, 2020 of a net debt to cash flow financial covenant contained in our renewed demand credit facility agreement assuming average realized natural gas and natural gas liquids' pricing of $1.86/Mcf and $41.76/Bbl, respectively. Consequently, when the next borrowing base redetermination under the demand credit facility commences as scheduled on (or before or later) May 31, 2020, because of depressed natural gas pricing and the forecasted breach, there can be no assurance provided that the borrowing base of the facility will be renewed at the same or similar amount or on the same or similar terms, nor can any assurance be provided that the lender will not call the debt as a result of the forecasted breach or for any other reason. In such event, if we are unable to secure alternative financing, there is significant doubt with respect to our ability to continue as a going concern.

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. 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:

Estimated cash flows and net debt

Estimated net debt upon the closing of the Transaction and estimated cash flows through to closing were used in the calculation of impairment for the year ended December 31, 2019. Estimated cash flows directly associated with our producing properties were based on future prices, costs and production rates. Estimated net debt includes such cash flows but it further includes future costs not directly associated with our producing properties. Management expects that these estimated cash flows will be revised, either upward or downward, based on updated information such as future realized commodity pricing, production and costs.

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 obligations

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.

Adopted New Accounting Standard

Effective January 1, 2019, we adopted *IFRS 16,* which replaced *IAS 17, Leases* ("IAS 17"), using a modified retroactive approach. This approach does not require restatement of prior period financial information as it applies the standard prospectively. Under IAS 17, operating lease payments were expensed on a straight line basis over the lease term whereas under IFRS 16, there is an increased focus on control of the underlying asset. Under IFRS 16, when we have a contract that transfers substantially all the risks and rewards incidental to ownership of an identified asset, we recognize a lease liability equivalent to the present value of future fixed payments over the contract's non-cancellable term or longer if it is reasonably likely we will exercise an option to extend that term. These future fixed payments are discounted using our incremental borrowing rate if the rate implicit in the lease is not readily determinable. Mineral licenses and surface leases that allow for the extraction of petroleum and natural gas are not within the scope of IFRS 16.

On adoption of IFRS 16, right-of-use assets were initially measured at the amount equal to the lease liabilities but as adjusted by the amount of the prepaids & deposits relating to leases reported at December 31, 2018. We also relied on a practical expedient that the assessment of our previous Calgary office space lease was onerous immediately before adopting IFRS 16 as an alternative to performing an impairment review. By choosing this practical expedient, we also decreased our right-of-use asset on adoption of IFRS 16 by the amount of the onerous contract provision reported at December 31, 2018. We measured the present value of our lease liabilities on adopting IFRS 16 using a discount rate of 6% as determined from our incremental borrowing rate. The adjustments to accounts measured at December 31, 2018 resulting from adopting IFRS 16 are as follows:

($ thousands)	As at December 31 2018	Adjustments	As at January 1 2019
Prepaids & deposits	$ 2,528	$ (244)	**$ 2,284**
Right-of-use assets	-	453	**453**
Lease liabilities	-	(599)	**(599)**
Provisions	(33,721)	390	**(33,331)**
Total	$ (31,193)	$ -	**$ (31,193)**

During the year to date, IFRS 16 caused a decrease of $0.4 million in G&A expense before recoveries (see "G&A Expense") whereas it increased DD&A (see "DD&A") by $0.4 million. As a result, our year to date adjusted funds outflow decreased by $0.4 million whereas the net loss was unaffected. The majority of the reported lease liabilities' amount on adoption of IFRS 16 was associated with our previous Calgary office space contract which expired on June 30, 2019.

Significant Accounting Policies

A summary of our significant accounting policies are included in the notes to the Financial Statements.

Disclosure Controls and Procedures

Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to us is made known to our CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by us in our annual filings, interim filings or other reports filed or submitted by us under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of our disclosure controls and procedures at December 31, 2019 and have concluded that our disclosure controls and procedures are effective at December 31, 2019.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICOFR") to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Our CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of our ICOFR at December 31, 2019 and have concluded that our ICOFR are effective at December 31, 2019. There were no changes in the ICOFR that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially affect our ICOFR.

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

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

Other Information

Non-GAAP Measures

Management believes that the presentation of the following non-GAAP measures provides useful information to investors and shareholders as these measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. 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 including those in the oil and natural gas industry:

- 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 costs. Adjusted funds flow (outflow) per share is calculated as adjusted funds flow (outflow) divided by the period's diluted shares. 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 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 (outflow) inflow from operating activities as determined in accordance with IFRS as an indicator of our financial performance. Adjustments to cash (outflow) inflow 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 is calculated as 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 deferred customer obligations, provisions and lease liabilities. We use net debt to assist us in understanding our liquidity at specific points in time. We exclude the current portion of deferred customer obligations, provisions and lease liabilities as they are either non-cash liabilities, estimates based on management's assumptions and subject to volatility or where the contractual benefit has yet to be received. Mark-to-market commodity contracts and assets and liabilities held for sale are excluded as they are unrealized estimates subject to a high degree of volatility prior to settlement.

- 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 loss 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 period's cash cost of operating expenses and net production expense per boe is used to measure operating efficiency on a comparative basis. This measure approximates our operating costs relative to only our volumes by excluding the approximated operating costs resulting from third party processing and gathering services.

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 Transaction and the anticipated timing of closing of the Transaction; timing of the annual and special meeting of Shareholders called to, among other things, approve the Transaction, and the benefits of the Transaction for Shareholders, forecasted breach of a financial covenant in our demand credit facility as at June 30, 2020, that we forecast minimal BC crown royalties through 2020, estimated annual cost savings of $2.0 million as a result of our new office lease, how we intend to manage our company and financial and business prospects and financial outlook for our company.

With respect to the forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: the time required to prepare Shareholder meeting materials in respect of the Transaction for mailing, the timing of receipt of necessary Court and shareholder approvals and the satisfaction of and time necessary to satisfy the conditions to the closing of the Transaction, that we will continue to conduct our operations in a manner consistent with that expressed herein, 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 and the continued availability of adequate debt and cash flow to fund our company. 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. In particular, we give no assurances that the Transaction will be completed. 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, the anticipated dates in this MD&A concerning the Transaction may change for a number of reasons, including unforeseen delays in preparing shareholder meeting materials, inability to secure necessary court or shareholder approval in the time assumed or the need for additional time to satisfy the conditions to the completion of the Transaction, failure to satisfy the conditions precedent to the closing of the Transaction, that in the event the Transaction is not completed our lender may reduce the availability of our $10.0 million demand credit facility or demand repayment of all outstanding debt and undrawn letters of credit precipitated by a forecasted financial covenant breach or for any other reason, and, in such event, that no sufficient alternative financing will be available to us, that there are material uncertainties that may cast significant doubt with respect to our ability to continue as a going concern, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, there is no certainty in the amount of our borrowing base redetermination, 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.

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
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.