Q1 2018

Management's Discussion and Analysis

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

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Chinook Energy Inc. ("CEI" or the "Corporation") and its subsidiaries, both wholly and partially owned, (collectively, "our", "we" or "us") for the three months ended March 31, 2018 and 2017 and should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes as at and for the three months ended March 31, 2018 and 2017 (the "Interim Financial Statements") and the audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2017 and 2016 (the "Audited Financial Statements). This MD&A is based on information available as at May 10, 2018.

The term "first quarter" or similar terms are used throughout this document and refer to the three months ended March 31, 2018. The term "same quarter of 2017" or similar terms are used throughout this document and refer to the three months ended March 31, 2017. The term "reported periods" or similar terms are used throughout this document and refer to both the three months ended March 31, 2018 and 2017, in this respective order. The term "fourth quarter" or similar terms are used throughout this document and refer to the three months ended December 31, 2017.

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

Additional Information

Additional information on our company, including our Annual Information Form for the year ended December 31, 2017 ("AIF"), can be found on SEDAR at www.sedar.com or at www.chinookenergyinc.com.

Basis of Presentation

The Interim Financial Statements have been prepared in accordance with International Accounting Standard 34 'Interim Financial Reporting' using accounting principles consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board. They include the accounts of our direct subsidiaries, all of which are wholly owned.

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.

Certain balances in the comparative period have been reclassified to conform to the current period's presentation.

Introduction to Chinook

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

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

Financial and Operating Highlights

Three months ended March 31		2018		2017
OPERATIONS				
Production (1)				
Natural gas liquids (boe/d)		**468**		482
Natural gas (mcf/d)		**13,806**		18,022
Crude oil (bbl/d)		**19**		29
Average daily production (boe/d) (2)		**2,788**		3,514
Sales Prices				
Average natural gas liquids price ($/boe)	**$**	**58.35**	$	51.39
Average natural gas price ($/mcf)	**$**	**2.64**	$	2.71
Average oil price ($/bbl)	**$**	**68.34**	$	60.32
Netback (3)				
Average commodity pricing ($/boe)	**$**	**23.35**	$	21.42
Royalty (expense) recovery ($/boe)	**$**	**(0.17)**	$	0.20
Realized (loss) gain on commodity price contract ($/boe)	**$**	**(1.18)**	$	1.38
Net production expense ($/boe) (3)	**$**	**(14.84)**	$	(11.27)
Operating netback ($/boe) (2) (3)	**$**	**7.16**	$	11.73
Wells Drilled (net)				
Exploration wells drilled (net)		**2.00**		-
FINANCIAL ($ thousands, except per share amounts)				
Petroleum & natural gas revenues, net of royalties	**$**	**5,815**	$	6,838
Adjusted funds flow (3)	**$**	**471**	$	2,036
Per share - basic & diluted ($/share)	**$**	**-**	$	0.01
Net (loss) income	**$**	**(2,098)**	$	10,422
Per share - basic and diluted ($/share)	**$**	**(0.01)**	$	0.05
Capital expenditures	**$**	**2,497**	$	8,823
Net (debt) surplus (3)	**$**	**(3,961)**	$	25,622
Total assets	**$**	**127,227**	$	148,665
Common Shares (thousands)				
Weighted average during period				
- basic		**223,565**		216,443
- diluted		**223,565**		216,900
Outstanding at period end		**223,565**		216,443

(1) Throughout this MD&A our production is presented in either barrels of oil ("bbl"), thousands of cubic feet ("mcf") or barrels of oil equivalent ("boe"); production per day is presented as bbl/d, mcf/d, and boe/d, respectively; commodity prices or revenues and expense per sales are presented as $/bbl, $/mcf, and $/boe, respectively. Production volumes and sales volumes are equal and are used interchangeably throughout this MD&A.
(2) May not be additive due to rounding.
(3) Non-GAAP measures which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.

Operations

Petroleum and Natural Gas Production Volumes

Three months ended March 31	2018	2017
Natural gas liquids (boe/d)	468	482
Natural gas (mcf/d)	13,806	18,022
Crude oil (bbl/d)	19	29
Total (boe/d)	2,788	3,514

Total Production Volumes

During the first quarter, our production decreased by 726 boe/d compared to the same quarter of 2017. Integrity issues on Enbridge's Oak 16" gathering line (the "Oak Pipeline") restricted our first quarter's volumes. This restriction, which began in November 2017, continued until a temporary pipeline was put in place in early April. With this third party restriction eased, our total production was approximately 5,400 boe/d during April. We achieved these volumes because of the fourth quarter's commissioning of our Birley facility expansion from 25 mmcf/d to 50 mmcf/d of raw natural gas. We are currently producing from 12 of 13 (10.29 net) of our Birley/Umbach horizontal wells.

Our 2018 production is expected to benefit from our 2016 and 2017 Montney drilling programs at our Birley/Umbach area that resulted in seven (6.27 net) horizontal wells. Six (5.33 net) of these seven wells contributed an additional 1,300 boe/d during the first quarter, despite production restrictions for reasons already explained, compared to the same quarter of 2017.

The first quarter's production volumes decreased compared to the 3,779 boe/d reported during the fourth quarter. This decrease was caused by the previously discussed Oak Pipeline integrity issue. This restriction affected the entirety of the first quarter whereas it only affected the latter portion of the fourth quarter.

Petroleum and Natural Gas Revenues and Realized Pricing

Three months ended March 31	2018	2017
($ thousands, except per unit amounts)		
Natural gas liquids sales	$ 2,458	$ 2,228
$/boe	58.35	51.39
Natural gas sales	$ 3,283	$ 4,391
$/mcf	2.64	2.71
Oil sales	$ 117	$ 156
$/bbl	68.34	60.32
Petroleum & natural gas revenue	$ 5,858	$ 6,775
$/boe	23.35	21.42

Our petroleum and natural gas revenue decreased for the first quarter compared to the same quarter of 2017. This decrease was the result of lower production volumes but partially offset by higher realized natural gas liquids pricing. As previously discussed, the lower production volumes resulted from a third party imposed restriction. The change in our realized commodity pricing was due to changes in natural gas and crude oil benchmarks. Also, our overall realized price per boe increased due to the higher ratio of natural gas liquid production relative to total production volumes that occurred due to liquid-rich Montney wells brought on-stream during the first quarter and throughout 2017. This is because natural gas liquids, on a heating equivalent basis, receive a higher price than natural gas.

Our average realized price during the first quarter increased 79% from the $13.02 boe/d reported during the fourth quarter. This significant increase was due to higher benchmark pricing but most notably higher Station 2 pricing.

Benchmark Prices

Three months ended March 31		2018		2017
Natural gas liquids				
Canadian light sweet [1] ($/bbl)	$	72.08	$	64.74
Natural gas				
BC Westcoast Station 2 [2] ($/mcf)	$	1.91	$	2.46
Chicago City Gate [3] (US$/mcf)	$	3.27	$	3.40

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

NGL Pricing

During the first quarter, consistent with higher Canadian light sweet oil and various other liquids and condensate benchmarks, our realized NGL pricing of $58.35/boe increased compared to the same quarter of 2017. Our NGL price is a blend of prices received for a range of liquids from ethane through to condensates that are produced in association with natural gas. There are various benchmarks for natural gas liquids, depending on the type sold; however, we benchmark our liquids in reference to Canadian light sweet oil. The ratio of our NGL price relative to Canadian light sweet oil was relatively unchanged at approximately 80% for both reported periods. This ratio was unchanged despite favorable effects which included an increase in the weighted average production volumes contributed from our liquid-rich Birley/Umbach area relative to our total production volumes and the prices for propane and condensates increasing at a greater rate than the increase in the Canadian light sweet benchmark. This ratio remained unchanged, despite the previously mentioned favorable effects, because they were offset by a 23% decrease in the benchmark price for ethane.

Our realized NGL price increased 12% during the first quarter compared to the $51.87/boe realized price reported during the fourth quarter. This increase was also due to an increase in the Canadian light sweet oil benchmark.

Natural Gas Pricing

Our realized natural gas price of $2.64/mcf during the first quarter modestly decreased compared to $2.71/mcf for the same quarter of 2017. This realized natural gas pricing change is due to decreases in benchmark pricing. Partially offsetting the benchmark pricing decreases was the weighted average ratio of natural gas production sold at each benchmark price relative to total natural gas production. Specifically, during the first quarter we sold 38% of our natural gas production at the Chicago City Gate benchmark compared to 27% in the same quarter of 2017. This increased ratio was due to lower natural gas production volumes, due to third party restrictions, relative to our firm 5,425 GJ/d natural gas volumes sold at Chicago City Gate pricing. Selling our natural gas at Chicago City Gate benchmark pricing results in us realizing a significant premium compared to Station 2 pricing. Also partially offsetting the benchmark pricing decreases was a higher ratio of natural gas production from our Birley/Umbach area relative to our total natural gas production. Our Birley/Umbach natural gas production has a higher heat content compared to the natural gas production from our other operations resulting in a higher realized natural gas price.

Our realized natural gas price increased 167% during the first quarter compared to the $0.99/mcf realized price reported during the fourth quarter. This increase was due to higher Station 2 benchmark pricing which increased 218% through the winter season.

Royalties

Three months ended March 31	2018	2017
($ thousands, except where noted)		
Royalty expense (recovery)	$ 43	$ (63)
Per sales ($/boe)	$ 0.17	$ (0.20)
Percent of revenues (%)	1	(1)

We are reporting negligible royalties for the reported periods. During 2017, we were granted royalty credits as part of BC's Infrastructure Royalty Credit Program (the "Infrastructure Program"). This program provides credits on our Birley/Umbach development only after sufficient crown royalties have been generated by specific wells. We recognized $0.2 million of these credits through a decrease to our royalties during both of the reported periods. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program. The 11 (9.47 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. We expect a twelfth well (1.0 net) to qualify for the deep well credit in 2018. Through the remainder of 2018 we are forecasting nominal BC crown royalties as a result of these credit programs combined with being a BC Montney focused play. Overriding and freehold royalties will continue to be payable.

Financial Commodity Price Contracts

To help mitigate commodity price risk, we enter into financial commodity price contracts which assist us in better managing our future adjusted funds flow. This provides more certainty within determined commodity price ranges as to what we will receive on a portion of our liquids and/or natural gas sales volumes. While these financial contracts may have opportunity costs when commodity benchmarks exceed the contracted prices, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Also, in accordance with the terms of our demand credit facility, if we have either an adjusted working capital deficit (see "Credit Facility") or debt draws, we are required to enter into commodity price contracts covering a minimum amount of our forecasted twelve month combined production volumes. We continuously review the need or requirement to utilize financial contracts.

When we have commodity price contracts outstanding at the end of a reporting period, they are reported at their approximated fair value on the date of the financial statements. This estimated fair value is partially determined through the difference in the referenced market forward price of the respective commodity over the remaining periods of the contracts compared to our received price multiplied by the remaining notional volumes. Volatility in forward commodity pricing and decreases in the remaining notional volumes will result in changes in the fair value of our derivative contracts from one period to the next. The change in the fair values between reported periods are recognized in net income (loss) as unrealized gains or losses on commodity price contracts. Realized gains or losses from these financial commodity price contracts are recognized in net income (loss) over the settlement term.

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

Three months ended March 31	2018	2017
($ thousands)		
Realized loss (gain) on commodity price contract	$ 295	$ (436)
Unrealized gain on commodity price contracts	(151)	(1,287)
Loss (gain) on commodity price contracts	$ 144	$ (1,723)
Realized (loss) gain on commodity price contracts ($/boe)	$ (1.18)	$ 1.38

As at March 31, 2018, our outstanding commodity price contract had the following terms:

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

During the current reporting period, we realized a loss on our Chicago City Gate price indexed contract as this benchmark was higher than our received price. If we had included this loss in our natural gas revenues, we would have reported an adjusted natural gas sales price for the first quarter of $2.40/mcf compared to our reported price of $2.64/mcf.

Our unrealized gain for the first quarter includes the decrease in the forward Chicago City Gas pricing relative to the US$2.68/mmbtu received fixed contract price. This unrealized gain resulted in a mark-to-market current financial asset of $0.2 million as at March 31, 2018.

Net Production Expense

Three months ended March 31		2018		2017
($ thousands, except where noted)				
Production & operating	$	4,011	$	3,824
Less:				
Processing & gathering revenues		(288)		(260)
Net production expense [1]	$	3,723	$	3,564
Net production expense ($/boe) [1]	$	14.84	$	11.27
Production expense ($/boe)	$	15.98	$	12.09

(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.

On a boe basis, production & operating expenses for the first quarter increased compared to the same quarter in 2017. This increase, despite lower production volumes, resulted in the reported periods having comparable total production & operating expenses. On a boe basis, the increased operating costs were due to the previously mentioned Oak Pipeline integrity issue and the resulting production restriction. This restriction had the effect of increasing the contribution, on a boe basis, from fixed operating costs relative to total operating costs. In addition, to prevent our production from freezing, we also incurred higher labour and steamer costs to flow restricted volumes through the extremely cold winter weather. These higher costs could have been avoided had our production been unimpeded.

We expect lower operating costs on a boe basis throughout the remainder of 2018 compared to both 2017 and the first quarter. The Oak Pipeline has now been temporarily replaced. As a result of our Birley/Umbach facility expansion, with this third party restriction eased, our production volumes have increased. This is expected to further lower, on a boe basis, the contribution from fixed operating costs relative to total operated costs. There are also no significant scheduled McMahon Plant turnarounds. We do not anticipate significant maintenance costs on our operated facilities.

We started reporting new toll revenue in June 2017 from our 12" Aitken Creek pipeline which is directly connected to the Alliance Pipeline. This resulted in higher processing and gathering revenue during the first quarter compared to the same quarter of 2017. However, this increase was partially offset by other producers' lower throughput through our facilities and distribution lines whose volumes, like ours, were also restricted.

Operating Netback

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

Three months ended March 31	2018	2017
Per sales ($/boe)		
Average commodity pricing	$ 23.35	$ 21.42
Royalty (expense) recovery	(0.17)	0.20
Realized (loss) gain on commodity price contracts	(1.18)	1.38
Net production expense [1]	(14.84)	(11.27)
Operating netback [1]	$ 7.16	$ 11.73

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

Our operating netback decreased during the first quarter compared to the same quarter of 2017 as a result of the effect of restricted volumes on our reported net production expense and a realized loss on our commodity price contract.

General & Administrative ("G&A") Expense

Three months ended March 31	2018	2017
($ thousands, except per unit amounts)		
G&A expense before recoveries	$ 1,861	$ 2,490
Recoveries	(690)	(878)
G&A expense	$ 1,171	$ 1,612
Per sales ($/boe)	$ 4.67	$ 5.10

We have continued to focus on improving our G&A cost structure through cost cutting initiatives. For the first quarter, we realized lower G&A expenses implemented throughout 2017 including lower staffing costs due to reductions in headcount, a lower number of directors, reduced employee benefits and reduced information system costs. Also, during the first quarter we reduced our headcount by 25% and suspended an employee benefit program. We estimate this will result in additional G&A cost savings of approximately $1.0 million per year. In addition, as a result of reporting an onerous contract non-cash charge during 2017, $0.2 million of rent expenditures during the first quarter that previously would have been reported as G&A expense instead reduced our onerous contract provision (see "Onerous Contract and Indemnifications"). If current rental market conditions remain the same or similar, we anticipate lower rent costs commencing in mid-2019 upon our lease expiration.

Partially offsetting the above G&A decreases were lower G&A recoveries. With lower compensation costs combined with reduced capital expenditures, our capitalized G&A, capital and other associated G&A recoveries decreased by $0.2 million during the first quarter compared to the same quarter of 2017.

G&A on a boe basis also decreased during the first quarter compared to the same quarter of 2017 as a result of the decrease in overall G&A expense described above. This decrease was despite the lower production caused by the previously mentioned third party restrictions.

We continue to assess our G&A expenses and make reductions where feasible. This includes a reduced work week during the spring and summer months.

Take or Pay Contract and Other (Income) Losses

Three months ended March 31	2018	2017
($ thousands)		
Take or pay contract revenue	$ (1,003)	$ (536)
Take or pay contract expense	$ 1,155	$ 629
Other (income) losses	$ (26)	$ 62

During the reported periods, we incurred a net fee for a take or pay processing agreement which we partially mitigated by purchasing production from a third party. We have partially mitigated our continued exposure to this agreement's costs at least through to the first quarter of 2019. The take or pay processing agreement expires on March 31, 2021.

Severance Costs

Three months ended March 31	2018	2017
($ thousands)		
Severance costs	$ 721	$ 373

Severance costs incurred during the reported periods related to staffing reductions resulting from a continuing assessment of our staffing requirements. As previously discussed, during the first quarter we reduced our headcount by 25%.

Exploration and Evaluation Expense

Three months ended March 31	2018	2017
($ thousands)		
Exploration & evaluation expense	$ 72	$ 92

Exploration and evaluation expense during the reported periods was in respect of geological and geophysical salaries and exploratory lease rental costs.

Gain on Dispositions of Properties

Three months ended March 31	2018	2017
($ thousands)		
Gain on dispositions of properties	$ -	$ (10,926)

The comparative period's gain was from the sale of certain assets located in the Knopcik/Pipestone and East Gold Creek areas of northwestern Alberta for net consideration of $17.8 million after customary closing adjustments.

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

Three months ended March 31	2018	2017
($ thousands, except per unit amounts)		
Depletion, depreciation & amortization	$ 2,220	$ 2,933
Depletion per sales ($/boe)	$ 7.16	$ 7.85

DD&A expense decreased on an overall and boe basis during the first quarter compared to the same quarter of 2017. The overall DD&A decrease resulted from both a lower depletion rate and production. This lower depletion rate was due to the fourth quarter's recognition of a $17.1 million impairment charge against the carrying value of our development and production assets. The lower depletion rate was also caused by an increase in the December 31, 2017 measure of our proved plus probable reserves.

Share-Based Compensation

Three months ended March 31	2018	2017
($ thousands)		
Share-based compensation	$ 91	$ 251

We granted share options and restricted awards during the first quarter. We previously granted these types of awards during the three months ended June 30, 2017. Combined, these granted awards had lower estimated fair values compared to grants during a prior year as respectively amortized during the reported periods. When combined with forfeitures of unvested awards caused by staffing reductions, this resulted in lower share-based compensation for the first quarter compared to the same quarter of 2017.

Amortization of Flow-Through Common Shares Premium

Three months ended March 31	2018	2017
($ thousands)		
Amortization of flow-through common shares premium	$ (323)	$ -

During the first quarter, we incurred the required $2.0 million of qualifying Canadian exploration expenditures pursuant to the December 11, 2017, issuance of 6,450,0000 common shares on a flow-through basis. As a result of incurring these exploration expenditures, during the first quarter we amortized the associated $0.3 million flow-through common shares premium.

Deferred Customer Obligation Amortization

Three months ended March 31	2018	2017
($ thousands)		
Deferred customer obligation amortization	$ (194)	$ -

During the third quarter of 2017, 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 the Aitken Creek pipeline.

Financing Expenses

Three months ended March 31	2018	2017
($ thousands)		
Interest & financing income	$ (12)	$ (84)
Accretion of provisions	174	169
Total	$ 162	$ 85

During the first quarter, our interest income decreased compared to the same quarter of 2017. This decrease resulted from using our cash-on-hand throughout 2017 and the first quarter to partially finance changes in non-cash working capital in addition to development, exploration and provision expenditures.

The accretion charges during the reported periods are comparable because a decrease in the applied decommissioning obligations’ discount rate was offset by a higher provision reported during 2017 caused by the drilling of four (3.63 net) Birley/Umbach wells and that area’s facility expansion from 25 mmcf/d to 50 mmcf/d.

Net & Comprehensive (Loss) Income

Three months ended March 31	**2018**	2017
($ thousands, except where noted)		
Weighted average shares outstanding - basic (thousands)	**223,565**	216,443
Dilutive impact of restricted and performance awards (thousands)	**-**	457
Weighted average shares outstanding - diluted (thousands)	**223,565**	216,900
Net & comprehensive (loss) income	**$ (2,098)**	$ 10,422
Net (loss) income per share - basic & diluted ($/share)	**$ (0.01)**	$ 0.05

For the first quarter we reported a net loss of $2.1 million compared to net income of $10.4 million during the same quarter of 2017. This decrease resulted from the absence during the first quarter, but as reported in the comparative quarter, of the $10.9 million gain on property dispositions and a $1.7 million gain from commodity price contracts. This decrease also reflected the first quarter's lower netback, restricted volumes and higher severance costs.

Capital Resources, Capital Expenditures and Liquidity

We successfully completed a $2.0 million issuance of common shares on a flow-through basis during December 2017. We used these proceeds in the first quarter to finance the drilling of two (2.0 net) exploratory vertical Birley/Umbach wells. These vertical wells have further delineated our contiguous Montney resource, preserved Birley/Umbach undeveloped lands and confirmed the fair value of our exploration & evaluation assets.

Despite the previously reported significant increase in our December 31, 2017, proved and proved plus probable reserves, relative to the prior year, and having a highly unleveraged balance sheet, with recent decreases in forward natural gas benchmark pricing we expect our lender to reduce the availability of our $18.0 million demand credit facility upon its scheduled May 31, 2018 reassessment. As at March 31, 2018, we had debt of $3.4 million. Our maximum expected debt draw is anticipated during the second quarter of 2018. Upon our demand credit facility's reassessment, we expect that our maximum debt draw will be less than the anticipated reassessed credit facility's availability.

We will continue to focus on capital preservation and optionality until we observe more constructive Station 2 benchmark pricing or we are otherwise able to secure more favorable natural gas pricing. Although our current capital program is nominal, we believe that our prior capital programs which saw us drill and complete 13 (11.23 net) wells on our Birley/Umbach property as well as complete the Birley facility expansion to 50 mmcf/d puts us in an excellent position to accelerate activity when commodity prices recover. We also believe that consolidation within our industry is required and would increase efficiencies amongst producers and streamline operations. We will continue to pursue opportunities that have the potential to generate additional value for our shareholders.

Adjusted Funds Flow

Three months ended March 31	**2018**	2017
($ thousands, except where noted)		
Cash outflow from operating activities	**$ (1,722)**	$ (1,445)
Add back:		
Change in operating non-cash working capital	**928**	2,923
Provision expenditures	**472**	93
Exploration & evaluation expenses	**72**	92
Severance costs	**721**	373
Adjusted funds flow [(1)]	**$ 471**	$ 2,036
Per share - basic & diluted	**$ -**	$ 0.01

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

For the first quarter, we reported a decrease in adjusted funds flow to $0.5 million compared to $2.0 million in the same quarter of 2017. This decrease resulted from restricted production volumes in addition to a realized loss on our commodity price contract. However, despite these factors, our first quarter adjusted funds flow is the seventh consecutive quarter we have reported positive adjusted funds flow which coincides with our transition to a Montney focused play.

Net (Debt) Surplus

	March 31 2018	December 31 2017
($ thousands)		
Debt	$ (3,401)	$ -
Cash	-	4,341
Accounts receivable	4,105	3,490
Prepaids & deposits	1,307	1,373
Accounts payable, accrued liabilities & other	(5,972)	(9,915)
Net debt [1]	$ (3,961)	$ (711)

(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 $4.0 million and $0.7 million at March 31, 2018 and December 31, 2017, respectively. This increase of $3.3 million was caused by development, provision, severance and exploration & evaluation expenditures of $3.8 million net of adjusted funds flow of $0.5 million, in addition to another non-cash working capital adjustment.

Credit Facility

As at March 31, 2018 and December 31, 2017, we had secured a demand credit facility agreement as amended with a Canadian chartered bank with availability of $18.0 million (the "Demand Credit Facility"). The Demand Credit Facility's next semi-annual review is scheduled for May 31, 2018. We expect our lender to reduce the availability of the Demand Credit Facility given recent decreases in forward Station 2 benchmark pricing. While there is no certainty in the amount of the borrowing base redetermination, we expect that our debt borrowings will be less than the anticipated reassessed Demand Credit Facility's availability. As at March 31, 2018, we had debt borrowings of $3.4 million and outstanding letters of credit of $0.8 million, as secured by our lender, which reduced the available Demand Credit Facility credit to $13.8 million (at December 31, 2017 – drawings of $nil, outstanding letters of credit of $0.8 million and available credit of $17.2 million).

All borrowings under the Demand Credit Facility have been classified as a current liability, as the lender can request repayment at any time of all outstanding drawn amounts. Changes in the availability in the Demand Credit Facility are possible, from one semi-annual review to the next, with draws in excess of availability becoming immediately payable. Borrowings incur interest at the prime rate plus an applicable margin and are collateralized by floating charges and security interests over all of our present and future properties and other assets.

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

As at the end of any month, if the greater of our adjusted working capital deficits or Demand Credit Facility draws are either up to $9.0 million or in excess of $9.0 million, within 60 days of the end of any such month, the terms of the Demand Credit Facility require that we enter into commodity price contracts covering no less than 30% or 50%, respectively, of our forecasted twelve month combined production volumes. For purposes of this compliance requirement, adjusted working capital deficit is current assets less current liabilities, excluding current commodity price contracts.

As at March 31, 2018, we were in compliance with the foregoing financial covenant and other requirements under the Demand Credit Facility except the mandatory commodity price contracts requirement. This requirement will be addressed in conjunction with the May 31, 2018 semi-annual review.

Capital Expenditures

Our capital expenditures during the reported periods were as follows:

Three months ended March 31		2018		2017
($ thousands)				
Land & lease	$	174	$	-
Drilling & completions		2,100		7,176
Facilities & equipment		73		1,415
Field expenditures		2,347		8,591
Capitalized G&A		150		232
Total	$	2,497	$	8,823
Proceeds from dispositions	$	-	$	17,838

During the first quarter, we drilled two (2.0 net) vertical exploratory wells in the Birley/Umbach area for $2.1 million. These wells further delineated 19 undrilled contiguous sections of 100% owned Montney rights (located three kilometres north of our main Montney land block and eight kilometres from the nearest well drilled into the Montney), as we evaluated the pay thickness and reservoir quality throughout the entire 235 metre thick Montney zone. These vertical wells were funded by the proceeds from our December 2017 flow-through share issuance. These 19 sections of Montney mineral rights north of our main Montney land block include the two sections we secured during the first quarter to reinforce our land position adjacent to the two (2.0 net) aforementioned exploratory Birley/Umbach vertical wells.

Provisions

Decommissioning Obligations

At March 31, 2018, the net present value of our decommissioning obligations was $31.0 million, which was relatively unchanged from the $31.1 million at December 31, 2017. We estimate this net present value based on a total future undiscounted and uninflated liability of $31.4 million (December 31, 2017 - $31.7 million). During the first quarter, $0.3 million in decommissioning obligation expenditures was mostly offset by accretion of $0.2 million which reflects the increase in the obligation associated with the passage of time.

As at March 31, 2018 and December 31, 2017, the estimated obligations include assumptions in respect of actual costs to abandon wells and facilities or reclaim the property, the time frame in which such costs will be incurred, as well as annual inflation of 2.0%, in order to calculate the future obligations. At March 31, 2018 and December 31, 2017, the average risk-free interest rate of 2.20% was used in order to calculate the present value of the obligations.

Onerous Contract and Indemnifications

During 2017, we recognized a provision caused by the onerous portion of our Calgary head office lease contract. This provision represents the present value of the minimum future lease payments we are obligated to make under the estimated onerous portion of the non-cancellable lease contract less estimated recoveries. At March 31, 2018, the undiscounted amount of future cash flows to settle this provision was $1.0 million. These cash flows have been discounted using a risk-free discount rate of 1.58%. The onerous contract provision is estimated to be settled in future periods through to June 2019.

We are involved in litigation and claims arising in the normal course of operations and from indemnifications provided to the buyer of our former Tunisian operations in 2014. At March 31, 2018, an estimate of probable future disbursements for these indemnifications, including professional costs, totaled $1.0 million.

Share Capital

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

	March 31 2018	December 31 2017
Common shares outstanding	**223,564,601**	223,564,601
Share options	**15,190,214**	10,276,884
Restricted awards	**243,800**	200,370
Weighted average common shares - basic and diluted	**223,564,601**	217,173,649

As at May 9, 2018, we had 223,604,601 common shares, 14,149,032 share options and 157,300 restricted awards outstanding.

Off Balance Sheet Arrangements

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

Outlook

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

We continue to prudently manage our production volumes and will continue to monitor commodity prices throughout the year and shut-in production where warranted.

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

Quarterly Information from Operations

Summarized information by quarter for the two years ended March 31, 2018, appears below:

	Mar. 31 2018	Dec. 31 2017	Sept. 30 2017	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016	Sept. 30 2016	Jun. 30 2016
Production Volumes								
Natural gas liquids (boe/d)	**468**	551	405	441	482	613	599	604
Natural gas (mcf/d)	**13,806**	19,240	14,109	19,065	18,022	21,548	28,972	22,776
Crude oil (bbl/d)	**19**	21	19	19	29	451	1,036	769
Average daily production (boe/d)	**2,788**	3,779	2,776	3,638	3,514	4,655	6,464	5,169
Sales Prices								
Average natural gas liquids price ($/boe)	**$ 58.35**	$ 51.87	$ 42.07	$ 44.48	$ 51.39	$ 40.70	$ 10.67	$ 25.78
Average natural gas price ($/mcf)	**$ 2.64**	$ 0.99	$ 1.20	$ 2.77	$ 2.71	$ 3.31	$ 2.22	$ 1.35
Average oil price ($/bbl)	**$ 68.34**	$ 76.96	$ 51.49	$ 59.55	$ 60.32	$ 71.98	$ 57.31	$ 50.59
Operating Netback (1)								
Average commodity pricing ($/boe)	**$ 23.35**	$ 13.02	$ 12.61	$ 20.22	$ 21.42	$ 27.67	$ 20.14	$ 16.50
Royalty (expense) recovery ($/boe)	**$ (0.17)**	$ (0.08)	$ 0.52	$ (0.33)	$ 0.20	$ (2.84)	$ (0.77)	$ (0.44)
Realized (loss) gain on derivative contracts ($/boe)	**$ (1.18)**	$ 3.83	$ 6.54	$ 1.01	$ 1.38	$ (0.35)	$ 1.84	$ 0.14
Net production expenses ($/boe) (1)	**$ (14.84)**	$ (11.06)	$ (12.32)	$ (11.82)	$ (11.27)	$ (11.88)	$ (12.61)	$ (14.75)
Operating netback ($/boe) (1)(2)	**$ 7.16**	$ 5.71	$ 7.35	$ 9.08	$ 11.73	$ 12.59	$ 8.60	$ 1.45
Wells Drilled (net)								
Wells drilled (net)	**2.00**	-	-	3.63	-	2.63	-	-
FINANCIAL *($ thousands, except per share amounts)*								
Petroleum & natural gas revenues, net of royalties	**$ 5,815**	$ 4,499	$ 3,351	$ 6,583	$ 6,838	$ 10,631	$ 11,518	$ 7,550
Adjusted funds flow (outflow) (1)	**$ 471**	$ 1,100	$ 647	$ 1,195	$ 2,036	$ 1,713	$ 1,894	$ (1,721)
Per share - basic & diluted ($/share)	**$ -**	$ 0.01	$ -	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ (0.01)
Net (loss) income (3)	**$ (2,098)**	$ (21,160)	$ (3,923)	$ (2,253)	$ 10,422	$ 6,427	$ (35,905)	$ (12,520)
Per share - basic & diluted ($/share)	**$ (0.01)**	$ (0.10)	$ (0.02)	$ (0.01)	$ 0.05	$ 0.03	$ (0.17)	$ (0.06)
Capital expenditures	**$ 2,497**	$ 7,253	$ 14,733	$ 8,235	$ 8,823	$ 4,177	$ 661	$ 1,347
Net (debt) surplus (1)	**$ (3,961)**	$ (711)	$ 3,616	$ 18,294	$ 25,622	$ 15,138	$ 7,217	$ 6,207
Total assets	**$ 127,227**	$ 130,571	$ 155,799	$ 144,891	$ 148,665	$ 139,975	$ 274,674	$ 366,586
Common Shares (thousands)								
Weighted average during period - basic	**223,565**	218,517	217,115	216,598	216,443	216,443	216,287	215,350
Weighted average during period - diluted	**223,565**	218,517	217,115	216,598	216,900	216,621	216,287	215,350
Outstanding at period end	**223,565**	223,565	217,115	217,115	216,443	216,443	216,443	215,350

(1) Non-GAAP measure which may not be comparable to similar non-GAAP measures used by other entities. Refer to the section entitled "Non-GAAP Measures" contained within this MD&A.
(2) May not be additive due to rounding.
(3) Includes $17.1 million, ($10.9 million) and $52.0 million in impairment (net reversal) charges against properties for the three months ended December 31, 2017, December 31, 2016 and September 30, 2016, respectively.

Factors That Have Caused Variations over the Quarters

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

Generally, the quarterly changes in operating and financial measures since the first quarter of 2017, in comparison to the 2016 quarters, result from previous Alberta assets which, during 2016, were either sold or as included in a share distribution. Beginning in the first quarter of 2017, our operating and financial results reflect the completion of our transition to a Montney play focused company. Upon transition, 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 five (4.27 net) came on-stream throughout 2017 with the remaining two (2.00 net) coming on-stream during the first quarter. However, extended third party restrictions did not allow us to demonstrate our production potential since the second half of 2017. With this restriction now eased, we are able to produce from all 13 (11.23 net) of our horizontal Birley/Umbach wells because of the on-time December 2017 commissioning of our facility expansion.

Beginning in the first quarter of 2017, on transition to a Montney focused natural gas company, our realized commodity prices began trending with the Station 2 benchmark pricing. Changes in our petroleum and natural gas revenues, net of royalties and adjusted funds flow have generally trended with the Station 2 and Western Canadian Select benchmark prices and volumes. During 2017, our net surplus has generally trended down as our capital expenditures exceeded our adjusted funds flow. This trend continued in the fourth and first quarters resulting in higher reported net debt. An exception was the first quarter of 2017 as a result of proceeds received from non-core asset distributions.

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

Risk Factors

Investors should carefully consider the risk factors set out in our AIF and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out in our AIF are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally. If any of 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".

Adopted New Accounting Standards

The Interim Financial Statements were prepared following the same accounting policies as summarized in note 3 in the Audited Financial Statements, except the policies for financial instruments and revenue recognition. These policies were respectively replaced upon the January 1, 2018 retroactive adoptions of IFRS 9 “Financial Instruments” and IFRS 15 “Revenue from Contracts with Customers”. IFRS 9 replaced the multiple classification and measurement models for financial assets with a single model that has three classifications categories: amortized cost, fair value through profit or loss and fair value through other comprehensive income. IFRS 15 provides a five-step model which includes identifying performance obligations. These adopted new accounting standards are detailed in note 3 to the Interim Financial Statements. The adoption of these standards did not have a material impact on the Interim 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.

Internal Controls over Financial Reporting

Our CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting (“ICOFR”) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. No material changes in our ICOFR were identified during the period beginning on January 1, 2018 and ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect our ICOFR.

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

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

Other Information

Non-GAAP Measures

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

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

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

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

- Net production expense is calculated as production and operating expense less processing and gathering revenues. We use net production expense to determine the current periods’ cash cost of operating expenses and net production expense per boe is used to measure operating efficiency on a comparative basis. 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: that we expect our 2018 production to benefit from our 2016 and 2017 Montney drilling programs and Birley/Umbach, that our operating costs will be lower on a boe basis during the remainder of 2018, that our production volumes will increase in 2018 due to no significant schedule McMahon Plant turnaround, the expected further lowering of our fixed operating costs relative to total operated costs, that we do not anticipate significant maintenance costs on our operated facilities in 2018, the anticipated reduction in expenses resulting from head- count reductions and the suspension of an employee benefit program, that our rent costs will decrease upon the expiration of our office lease in mid-2019, that our debt draw will be less than the upcoming reassessed credit facility’s availability, that we expect to renegotiate the Demand Credit Facility’s mandatory hedging requirement during the next semi-annual review on May 31, 2018, that we will continue to focus on capital preservation and optionality until Station 2 benchmark pricing improves or we are otherwise able to secure more favorable natural gas pricing, that our previous capital program has put us in an excellent position to accelerate activity when commodity prices recover, that our capital plan for the remainder of 2018 will be minimal and will be continuously reviewed by our management and board of directors with adjustments made in response to changing market conditions, that we may voluntarily shut-in volumes throughout the year when warranted by commodity prices, that we believe that consolidations would increase efficiencies among producers and streamline operations and that we will pursue opportunities that have potential to generate additional value for our shareholders, future exploration and development activities and the timing thereof and how we intend to manage our company.

With respect to the forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things: that we will continue to conduct our operations in a manner consistent with that expressed herein, no significant future capital expenditure levels, future oil and natural gas prices, future oil and natural gas production levels, future currency, exchange and interest rates, our ability to obtain equipment in a timely manner to carry out exploration and development activities, the ability of the operator of the projects in which we have an interest in to operate in the field in a safe, efficient and effective manner, the impact of increasing competition, field production rates and decline rates, anticipated production volumes, our ability to replace and expand production and reserves through exploration and development activities, certain cost assumptions, that the budgeted capital program for remainder of 2018, which is subject to the discretion of our Board of Directors, will not be amended in the future, and the continued availability of adequate debt and cash flow to fund our planned expenditures. Although we believe that the expectations reflected in the forward-looking statements contained in this MD&A, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this MD&A, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, without limitation, anticipated third party restrictions, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and currency fluctuations, our Board of Directors may amend the capital program for the remainder of 2018 based on its discretion; environmental risks, competition from other producers, inability to retain drilling rigs and other services, unanticipated increases in or unforeseen capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, delays in projects and/or operations resulting from surface conditions, wells not performing as expected, delays resulting from or inability to obtain the required regulatory approvals and inability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the forgoing list of factors is not exhaustive. Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at our website (www.chinookenergyinc.com). Furthermore, the forward-looking statements contained in this MD&A are made as at the date of this MD&A and we do not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Future Oriented Financial Information

This MD&A may contain Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by our management to provide an outlook of our activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward-Looking Statements" and assumptions with respect to production rates and commodity prices. The actual results of our operations and the resulting financial results may vary from the amounts set forth herein, and such variation may be material. Our management believes that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments.

Selected Definitions and Abbreviations

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

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

Barrels of Oil Equivalent

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