MANAGEMENT'S DISCUSSION AND ANALYSIS

SEPTEMBER 30, 2019

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The following is management's discussion and analysis ("MD&A") of BNK Petroleum Inc.'s ("BNK" or the "Company") operating and financial results for the three months and nine months ended September 30, 2019, compared to the corresponding periods in the prior year, as well as information and expectations concerning the Company's outlook based on currently available information. The MD&A should be read in conjunction with the unaudited condensed consolidated interim financial statements for the three and nine months ended September 30, 2019 and the audited consolidated financial statements and MD&A for the year ended December 31, 2018. The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2018. The reporting and measurement currency is the United States dollar. Additional information relating to BNK including its Annual Information Form is filed on SEDAR at www.sedar.com and on the Company's website at www.bnkpetroleum.com.

This report is prepared as of November 7, 2019. Please read carefully the important cautionary notes regarding technical information, forward-looking statements and other matters set out in this report.

Description of Business

BNK Petroleum Inc. is an international energy company focused on finding and exploiting large, predominantly unconventional oil and gas resource plays. The Company's focus is on maximizing the value of its existing assets in the United States, while targeting growth in production and reserves through the acquisition of exploration and production rights that it considers to be prospective for hydrocarbons by applying new and proven technologies by its experienced technical team. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol "BKX" and on the Over the Counter QX ("OTCQX") under the symbol "BNKPF".

Operating Summary

The Company's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for the production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather and general economic conditions.

OVERVIEW

Results at a Glance

	Three Months ended September 30,		Nine Months ended September 30,	
	2019	**2018**	**2019**	**2018**
Financial (US $000 except per share)				
Oil and gas gross revenues	**5,166**	8,378	**16,739**	23,724
Net operating income[(1)]	**3,170**	5,566	**10,474**	15,021
Net income (loss)	**1,420**	1,184	**1,474**	(111)
Basic and diluted net income (loss) per share	**0.01**	0.01	**0.01**	(0.00)
Cash flow from operating activities	**1,986**	3,434	**5,902**	9,264
Adjusted funds flow[(2)]	**2,233**	3,875	**7,332**	10,253
Additions to property, plant and equipment	**195**	2,188	**1,310**	13,771
Operating				
Average production (Boepd)	**1,341**	1,534	**1,397**	1,700
Average price ($/BOE)	**41.87**	56.91	**43.89**	53.78
Netback from operations ($/BOE)[(3)]	**25.69**	38.33	**27.47**	35.39
Netback including commodity contracts ($/BOE)[(3)]	**24.63**	32.62	**25.87**	31.17
Netback after adjustments ($/BOE)[(3)]	**24.63**	33.73	**25.87**	28.16

	September 30, 2019	June 30, 2019	March 31, 2019	December 31, 2018
Balance Sheet				
Cash and cash equivalents	**2,064**	**2,855**	1,708	1,456
Total assets	**161,598**	**163,185**	163,118	164,559
Working capital (deficiency)	**(376)**	**(598)**	(2,969)	(2,393)
Total non-current liabilities	**28,286**	**30,777**	30,853	30,687

(1) Net operating income is considered a non-GAAP measure. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(2) Adjusted Funds Flow is considered a non-GAAP measure. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(3) Netback from operations, netback including commodity contracts and netback after adjustments are considered non-GAAP measures. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

Highlights

Average production for the third quarter of 2019 was 1,341 BOEPD, a decrease of 13% compared to the third quarter of 2018 average production of 1,534 BOEPD. Average production for the nine months ended September 30, 2019 was 1,397 BOEPD, a decrease of 18% from the average production of 1,700 BOEPD in the same period of 2018. The 2018 average production included prior period adjustments related to natural gas and NGL volumes in 2018 which reduced production by 77 boepd for the three months ended September 30, 2018 and increased production by 122 boepd for the nine months ended September 30, 2018. There were no prior period adjustments in 2019. Excluding the impact of the prior period adjustments, average production decreased 17% for the third quarter of 2019 and 11% for the first nine months of 2019 compared to the comparable prior year periods. Also, the WLC 14-1H well came back on production in August 2019 and the Company was able to recover approximately 70% of the lost production. The decrease from the prior year quarter was primarily due to the normal production decline of existing wells.

Gross revenues for the third quarter of 2019 decreased by 38% compared to the third quarter of 2018. Gross revenues for the nine months ended September 30, 2019 decreased by 29%. These decreases in revenues were primarily due to the decreases in production and average prices in 2019 compared to the same periods in the prior year.

Adjusted funds flow(1) was $2.2 million for the third quarter of 2019 compared to $3.9 million in the third quarter of 2018. Adjusted funds flow(1) was $7.3 million for the nine months ended September 30, 2019 compared to $10.3 million for the comparable prior year period. The decreases were mainly due to lower revenue caused by lower production and average prices.

Netbacks from operations(2) decreased from $38.33 per BOE in the third quarter of 2018 to $25.69 per BOE in 2019, a decrease of 33%. Netbacks from operations(2) decreased from $35.39 per BOE for the nine months ended September 30, 2018 to $27.47 per BOE for the first nine months of 2019, a decrease of 23%. The decreases in 2019 were due to the decreases in production and average prices compared to the same periods in the prior year.

Net income for the third quarter of 2019 was $1.4 million compared to net income of $1.2 million in 2018. The Company had an unrealized gain on financial commodity contracts of $1.3 million in the third quarter of 2019, compared to an unrealized loss of $0.2 million in the third quarter of 2018. Net income for the first nine months of 2019 was $1.5 million compared to net loss of $0.1 million in 2018. The Company had an unrealized gain on financial commodity contracts of $0.6 million in the first nine months of 2019, compared to an unrealized loss of $2.5 million in the first nine months of 2018.

The Company's US subsidiary has a credit facility from BOK Financial, with a commitment amount of $30.0 million at September 30, 2019. At September 30, 2019, the US subsidiary had an outstanding balance of $27.5 million on the credit facility after paying down $2.5 million during the third quarter of 2019.

(1) Adjusted funds flow is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.
(2) Netback from operations and netback after adjustments are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Tishomingo Field, Ardmore Basin, Oklahoma

Average production for the third quarter of 2019 was 1,341 BOEPD, a decrease of 13% compared to the third quarter of 2018 average production of 1,534 BOEPD. Average production for the nine months ended September 30, 2019 was 1,397 BOEPD, a decrease of 18% from the average production of 1,700 BOEPD in the same period of 2018. The 2018 average production included prior period adjustments related to natural gas and NGL volumes in 2018 which reduced production by 77 boepd for the three months ended September 30, 2018 and increased production by 122 boepd for the nine months ended September 30, 2018. There were no prior period adjustments in 2019. Excluding the impact of the prior period adjustments, average production decreased 17% for the third quarter of 2019 and 11% for the first nine months of 2019 compared to the comparable prior year periods. Also, the WLC 14-1H well came back on production in August 2019 and the Company was able to recover approximately 70% of the lost production. The decrease was primarily due to the normal production decline of existing wells.

DISCUSSION OF OPERATING RESULTS

Production and Revenue

	Three months ended September 30			Nine months ended September 30		
	2019	**2018**	%	**2019**	**2018**	%
Average oil production (BOPD)	**955**	**1,182**	(19)	**1,019**	**1,154**	(12)
Average natural gas production (MCFPD)	**990**	**789**	25	**1,024**	**1,901**	(46)
Average NGL production (BOEPD)	**221**	**220**	-	**207**	**229**	(10)
Average production (BOEPD)	**1,341**	**1,534**	(13)	**1,397**	**1,700**	(18)
Average oil price ($/bbl)	**54.41**	**69.18**	(21)	**54.96**	**65.87**	(17)
Average natural gas price ($/mcf)	**1.96**	**2.08**	(6)	**2.64**	**2.33**	13
Average NGL price ($/bbl)	**10.18**	**34.89**	(71)	**12.50**	**28.35**	(56)
Average price ($/BOE)	**41.87**	**56.91**	(26)	**43.89**	**53.78**	(18)
Oil revenue ($000)	**4,781**	**7,521**	(36)	**15,293**	**20,743**	(26)
Natural gas revenue ($000)	**178**	**151**	18	**739**	**1,212**	(39)
NGL revenue ($000)	**207**	**706**	(71)	**707**	**1,769**	(60)

Oil production for the third quarter of 2019 averaged 955 BOPD compared to 1,182 BOPD for the same period in 2018, a decrease of 19%. Average oil production for the first nine months of 2019 was 1,019 BOPD compared to 1,154 for the same period in 2018, a decrease of 12%. The production decreases are primarily due to the natural decline of existing wells. Oil revenue decreased by 36% in the third quarter of 2019 versus the comparable period in 2018 due to a 21% decrease in oil prices and a 19% decrease in oil production. Oil revenue decreased by 26% in the first nine months of 2019 versus the comparable period in 2018 due to a 17% decrease in oil prices and a 12% decrease in oil production.

During the third quarter of 2019, average natural gas production was 990 MCFPD compared to 789 MCFPD for the same period in 2018, an increase of 25%. Average natural gas production for the first nine months of 2019 was 1,024 MCFPD compared to 1,901 MCFPD in the same period in 2018, a decrease of 46%. The increase in the third quarter is due to prior period adjustments the Company received for its natural gas volumes sold due to the purchaser remeasuring prior volumes which reduced natural gas production by 565 MCFPD in the third quarter of 2018. The decrease in the first nine months of 2019 is due to prior period adjustments the Company received for its natural gas volumes sold due to the purchaser remeasuring prior volumes which increased production by 634 MCFPD in the first nine months of 2018. There were no prior period adjustments in 2019. Excluding the impact of the prior period adjustments, average natural gas production decreased by 27% for the third quarter of 2019 and 20% for the first nine months of 2019 compared to the comparable prior year periods due primarily to the normal production declines of existing wells. Natural gas revenue increased by 18% in the third quarter of 2019 versus the comparable period in 2018 due to a 25% increase in gas production partially offset by a 6% decrease in average price. Natural gas revenue decreased by 39% in the first nine months of 2019 versus the same period in 2018 due to a 46% decrease in production partially offset by a price increase of 13%.

Average natural gas liquids (“NGL”) production in the third quarter of 2019 was flat at 221 BOEPD compared to 220 BOEPD in the comparable period in 2018. Average NGL production for the first nine months of 2019 decreased to 207 BOEPD from 229 BOEPD for the same period in 2018, a decrease of 10%. The decrease is primarily due to prior period adjustments that the Company received for its NGL volumes sold due to the purchaser remeasuring prior volumes which increased NGL production by 17 BOEPD in the third quarter of 2018 and increased production by 16 BOEPD in the first nine months of 2018. There were no prior period adjustments in 2019. Excluding the impact of the prior period adjustments, average NGL production increased by 8% for the third quarter of 2019 and decreased by 3% for the first nine months of 2019 compared to the comparable prior year periods. NGL revenue decreased by 71% in the third quarter of 2019 versus the comparable period in 2018 due to a 71% decrease in NGL prices. NGL revenue decreased by 60% in the first nine months of 2019 versus the comparable period in 2018 due to a decrease in NGL production of 10% and a 56% decrease in NGL prices.

Average production on a per BOE basis was 1,341 BOEPD in the third quarter of 2019 compared to 1,534 BOEPD in the comparable period in 2018, a decrease of 13%. Average production on a per BOE basis was 1,397 BOEPD in the first nine months of 2019 compared to 1,700 BOEPD in the comparable period in 2018, a decrease of 18%. These decreases are due to a combination of the factors discussed above.

Gross revenue in the third quarter of 2019 decreased by 38% compared to the third quarter of 2018 due to a 13% decrease in average production and a 26% decrease in average prices. Gross revenue for the first nine months of 2019 decreased by 29% compared to the same period in 2018 due to a 18% decrease in average production and a 18% decrease in average prices.

Royalties, Operating Expenses and Netbacks[1]

	Three months ended September 30			**Nine months ended September 30**		
($/BOE)	**2019**	2018	%	**2019**	2018	%
Average price	**41.87**	56.91	(26)	**43.89**	53.78	(18)
Less: Royalties	**8.61**	10.62	(19)	**9.06**	11.60	(22)
Less: Operating expenses	**7.57**	7.96	(5)	**7.36**	6.79	8
Netback from operations [1]	**25.69**	38.33	(33)	**27.47**	**35.39**	(22)
Price adjustment from commodity contracts [2]	**(1.06)**	(5.71)	(81)	**(1.60)**	(4.22)	(62)
Netback including commodity contracts[1]	**24.63**	32.62	(24)	**25.87**	**31.17**	(17)
Prior period adjustments[3]	**-**	1.11	-	**-**	(3.01)	-
Netback after adjustments[1]	**24.63**	33.73	(27)	**25.87**	**28.16**	(8)

(1) Netback from operations, netback including commodity contracts and netback after adjustments are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.
(2) Price adjustment from commodity contracts includes the positive or negative adjustment to the average price per barrel that the Company realized from its commodity contracts. See the listing of commodity contracts below.
(3) The Company received prior period adjustments for its natural gas and NGL volumes sold and processing costs related to prior years due to the purchaser re-measuring prior volumes and reassessing prior gathering and processing costs. For the three months ended September 30, 2018, prior period adjustments includes the per BOE impact of a decrease of $161,000 in natural gas sales, an increase of $105,000 in NGL sales and $88,000 of additional operating expenses related to a decrease in sales volumes of 565 MCFPD in natural gas and an increase of 17 BOEPD in NGLs related to prior year periods. For the nine months ended September 30, 2018, prior period adjustments includes the per BOE impact of an increase of $391,000 in natural gas sales, $168,000 in NGL sales and $686,000 of additional operating expenses related to an increase in sales volumes of 654 MCFPD and 16 BOEPD in NGLs related to prior year periods.

The average price decrease in the third quarter was due to price decreases in oil, natural gas and NGLs. The price decrease in the first nine months of 2019 was due to price decreases in oil and NGLs, partially offset by an increase in natural gas prices. Oil made up 71% of the production mix in the third quarter of 2019 compared to 77% oil in the production mix for the third quarter of 2018 and oil made up 73% of the production mix for the first nine months of 2019 compared to 68% oil mix in the first nine months of 2018.

Royalties on Tishomingo production averaged approximately 20.6% for the third quarter of 2019 versus 18.4% for the same period in 2018.

Major operating expenses are related to the gathering and processing of natural gas and NGLs as well as periodic well repairs and maintenance. Operating expenses in the third quarter of 2019 were $0.9 million compared to $1.3 million in the third quarter of 2018. Operating expenses in the third quarter of 2019 averaged $7.57 per BOE compared to $7.96 per BOE for the same period in 2018 (excluding the prior period adjustments). Operating expenses for the first nine months of 2019 were $2.8 million compared to $3.6 million in the first nine months of 2018. Operating expenses for the first nine months of 2019 averaged $7.36 per BOE compared to $6.79 per BOE for the same period in 2018 (excluding the prior period adjustments). The operating expense per BOE amounts for the first nine months of 2019 include the impact of a production tax increase in July 2018 which increased the first nine months of 2019 amount by $0.41 per boe compared to the prior year period.

Realized and Unrealized Gains and Losses from Risk Management Contracts

The Company entered into financial commodity contracts which are summarized in the table below. Total Volume Hedged in the table is the annual volumes and Price is the fixed price specified in the financial commodity contracts.

At September 30, 2019 the following financial commodity contracts were outstanding and recorded at estimated fair value:

Commodity	Period	Total Volume Hedged (BBLS/MMBTU)	Price ($/BBL or $/MMBTU)
Oil - WTI	October 1, 2019 to December 31, 2019	24,470	$48.40
Oil - WTI	January 1, 2020 to April 30, 2020	30,920	$48.40
Oil – WTI	October 1, 2019 to October 31, 2019	278	$51.55
Oil - WTI	October 1, 2019 to December 31, 2019	4,500	$54.16
Oil - WTI	October 1, 2019 to December 31, 2019	4,500	$55.03
Oil - WTI	October 1, 2019 to December 31, 2019	18,400	$60.30
Oil - WTI	January 1, 2020 to April 30, 2020	12,100	$59.27
Oil - WTI	May 1, 2020 to December 31, 2020	49,000	$58.05
Oil - WTI	January 1, 2020 to December 31, 2020	88,784	$58.50
Gas - Henry Hub	October 1, 2019 to December 31, 2019	33,283	$2.93
Gas - Henry Hub	January 1, 2020 to March 31, 2020	31,571	$2.93
Gas - Henry Hub	January 1, 2020 to December 31, 2020	129,256	$2.65

The estimated fair value results in a $1.0 million asset as of September 30, 2019 (December 31, 2018: $0.4 million asset) for the financial oil and gas contracts which has been determined based on the prospective amounts that the Company would receive or pay to terminate the contracts, consisting of current asset of $0.6 million and long term assets of $0.4 million (December 31, 2018: current asset of $0.4 million).

The realized and unrealized gains/losses from the financial commodity contracts are as follows:

($000s)	Three months ended September 30,		Nine months ended September 30,	
	2019	**2018**	**2019**	**2018**
Realized loss on financial commodity contracts	(129)	(805)	(608)	(1,960)
Unrealized gain (loss) on financial commodity contracts	1,262	(232)	588	(2,454)

General and Administrative Expenses

General and administrative expenses (G&A) for the third quarter of 2019 were $811,000 compared to $885,000 for the same period of 2018, a decrease of 8%. G&A for the first nine months of 2019 was $2,548,000 compared to $2,822,000 for the same period of 2018, a decrease of 10%. The decreases in G&A compared to 2018 relate to cost cutting efforts, lower rent expense from the adoption of IFRS 16 and advisor fees incurred in the first nine months of 2018.

Depletion and Depreciation

Depletion and depreciation expense for the third quarter of 2019 was $1.5 million compared to $1.9 million in the same period of 2018. Depletion and depreciation expense for the first nine months of 2019 was $4.7 million compared to $6.2 million in the same period of 2018. The decrease for both periods is due to increased reserves in 2019 and decreased production. Depletion and depreciation expense on a per barrel basis was $12.41 for the third quarter of 2019 compared to $13.32 in the third quarter of 2018. Depletion and depreciation expense on a per barrel basis was $12.41 for the first nine months of 2019 compared to $13.31 for the same period of 2018.

Share based compensation

Share based compensation decreased from $57,000 for the third quarter of 2018 to $27,000 in the third quarter of 2019. For the first nine months of 2019, share based compensation decreased from $279,000 to $121,000. The decreases were due to stock option grants in April of 2018.

Interest on loans and borrowings

Interest on loans and borrowings were $502,000 for the third quarter of 2019 versus $515,000 for the third quarter of 2018. Interest expense increased to $1,552,000 in the first nine months of 2019 compared to $1,434,000 for the same period of 2018. The increase is due to a higher loan balance in 2019.

Net income (loss) for the period

The Company had net income of $1,420,000 ($0.01 per share) for the third quarter of 2019 compared to net income of $1,184,000 ($0.01 per share) for the same period of 2018. The increase in net income is due to a gain in financial commodity contracts in the third quarter of 2019 of $1,133,000 versus a loss of $1,037,000 in the third quarter of 2018, a decrease in depletion, depreciation and accretion of $348,000, a decrease in operating expenses of $334,000, a decrease in general and administrative costs of $74,000, partially offset by a decrease in revenue net of royalties of $2,730,000.

The Company had net income of $1,474,000 ($0.01 per share) for the first nine months of 2019 compared to a net loss of $111,000 ($0.00 per share) for the same period of 2018. The net income compared to a net loss in the same period in 2018 is due to a loss in financial commodity contracts in 2019 of $20,000 versus a loss of $4,414,000 in 2018, a decrease in depletion, depreciation and accretion of $1,443,000, a decrease in operating costs of $803,000, a decrease in general and administrative costs of $274,000, a decrease in share based compensation of $158,000, partially offset by a decrease in revenue net of royalties of $5,350,000 and an increase in interest on long term debt of $118,000.

Cash from continuing operating activities

Cash flows from continuing operating activities for the third quarter of 2019 was $1,986,000 compared to cash flows from continuing operating activities of $3,434,000 for the same period in 2018. Cash flows from continuing operating activities for the first nine months of 2019 was $5,902,000 compared to cash flows from continuing operating activities of $9,264,000 for the same period in 2018.

CAPITAL EXPENDITURES

Capital expenditures in 2019 were for the Anderson 1-15H10X3 well (non-operated, BNK 33% working interest) and workovers on operated wells in the Tishomingo field located in Oklahoma.

($000)	Nine months ended September 30	
	2019	2018
Additions to oil and gas properties	**$ 1,310**	$ 13,771
	$ 1,310	$ 13,771

LIQUIDITY AND CAPITAL RESOURCES

	At September 30, 2019	**At December 31, 2018**
Working Capital Deficiency (US$)	$ **(376,000)**	**$ (2,393,000)**
Loans and Borrowings (US$)	$ **27,500,000**	$ **30,000,000**
Shares Outstanding, end of period	**232,922,625**	**232,922,625**
Market Price per share, end of period (in Canadian $)	**$ 0.15**	**$ 0.33**
Market Value of Shares (in Canadian $)	**$ 34,938,000**	**$ 76,900,000**

In June 2017, the Company's US subsidiary obtained a new credit facility from BOK Financial, which is secured by the US subsidiary's interests in the Tishomingo Field. The credit facility has a current commitment amount of $30.0 million and is intended to fund the drilling of the Caney wells in the Tishomingo Field. Additional commitment amounts will be subject to new reserve evaluations and there is no guarantee that the borrowing base will remain at current levels. The credit facility is subject to a semi-annual review and redetermination of the borrowing base. Any redetermination of the borrowing base is effective immediately and if the borrowing base is reduced, the Company has six months to repay any shortfall. The credit facility was redetermined in May 2019 at its existing borrowing base and the next redetermination will occur in the fourth quarter of 2019. There is no guarantee that the size and terms of the credit facility will remain the same after the borrowing base redetermination. As of September 30, 2019, the US subsidiary has $27.5 million of the credit facility outstanding. The Company paid down $2.5 million of the commitment amount in the third quarter of 2019.

Primary debt covenants of the facility require the US subsidiary to maintain a positive working capital balance which includes any unused excess borrowing capacity and excludes the fair value of commodity contracts (the “Current Ratio”) and to ensure the ratio of outstanding debt and long-term liabilities to an annualized quarterly adjusted EBITDA amount (the “Maximum Leverage Ratio”) be no greater than 4 to 1 at any quarter end. Adjusted EBITDA is defined as net income excluding interest expense, depreciation, depletion and amortization expense, and other non-cash charges including stock based compensation expense and unrealized gains or losses on commodity contracts. The Company was in compliance with these covenants for the quarter ended September 30, 2019. At September 30, 2019, the Current Ratio of the US subsidiary was 1.27 to 1.0 and the Maximum Leverage Ratio was 3.03 to 1.0 for the three months ended September 30, 2019.

At September 30, 2019, loans and borrowings of $27.5 million (December 31, 2018: $30 million) are presented net of loan acquisition costs of $0.4 million (December 31, 2018: $0.4 million).

At September 30, 2019, the Company had negative working capital of $0.3 million, versus negative working capital of $2.4 million at December 31, 2018. At September 30, 2019, the Company had $2.5 million of available capacity on its credit facility. The Company closely monitors its working capital and borrowing capacity to ensure adequate funds are available to finance its administrative and operating requirements. The Company does not have any drilling commitments and therefore has the ability to operate within its cash flows.

The Company has entered into financial commodity contracts as part of its risk management strategy to manage its cash flow for future activity and to offset commodity price fluctuations. The Company believes that the combination of cash on hand and cash flow from operations will be sufficient to finance the Company’s cash requirements through the next twelve months. Other potential sources of cash flow include proceeds from additional debt or equity offerings.

CONTRACTUAL OBLIGATIONS

The following are the contractual maturities of financial liabilities, excluding estimated interest payments at September 30, 2019:

($000)	Total	2019	2020	2021	2022
Loans and borrowings *	$27,134	-	-	-	$27,134
Trade and other payables	5,515	5,515	-	-	-
Lease payable	143	116	27		
	$32,792	5,631	27	-	$27,134

* The Credit Facility provides for interest only payments until the June 2022 maturity date. The Company is required to repay amounts owing under the Credit Facility in full on the June 2022 maturity date. See “Liquidity and Capital Resources” and “Principal Business Risks” for discussion of events that would require early repayment of the Credit Facility.

QUARTERLY SUMMARY

Below is a summary of the Company's performance over the last eight quarters:

	2019			2018				2017
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Daily Production								
Oil (BOPD)	955	1,001	1,103	1,043	1,182	1,288	989	1,137
Natural gas (MCFPD)	990	1053	1029	1,389	789	3,328	1,597	1,119
NGL's (BOEPD)	221	178	223	280	220	257	209	215
Average production (BOEPD)	1,341	1,355	1,498	1,555	1,534	2,100	1,464	1,539

	2019			2018				2017
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Average Price								
Oil ($/bbl)	54.41	58.07	52.60	57.69	69.18	66.17	61.43	53.26
Natural gas ($/mcf)	1.96	2.63	3.34	2.23	2.08	2.26	2.62	2.52
NGL ($/bbl)	10.18	16.19	11.87	31.73	34.89	25.01	25.47	29.17
Average price ($/bbl)	41.87	47.06	42.80	46.41	59.37	47.24	47.97	45.27

	2019			2018				2017
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Netback[(1)]								
Average price ($/BOE)	41.87	47.06	42.8	47.11	56.91	54.31	49.45	45.27
Royalties	8.61	9.73	8.85	10.2	10.62	13.12	10.85	9.66
Operating expenses	7.57	7.66	6.89	7.24	7.96	5.59	6.91	5.8
Netback from operations[(1)]	25.69	29.67	27.06	29.67	38.33	35.6	31.69	29.81
Price adjustment from commodity contracts	(1.06)	(2.47)	(1.29)	(1.78)	(5.71)	(3.85)	(3.18)	0.65
Netback including commodity contracts[(1)]	24.63	27.2	25.77	27.89	32.62	31.75	28.51	30.46
Prior period adjustments[(4)]	-	-	-	(0.77)	1.11	(6.78)	(1.74)	-
Netback after adjustments[(1)]	24.63	27.2	25.77	27.12	33.73	24.97	26.77	30.46

	2019			2018				2017
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Net operating income[(2)]								
Oil and gas revenue	5,166	5,802	5,771	6,640	8,378	9,027	6,319	6,409
Royalties	1,062	1,201	1,194	1,438	1,544	2,161	1,387	1,366
Operating expenses	934	945	929	1,067	1,268	1,356	987	821
	3,170	3,656	3,648	4,135	5,566	5,510	3,945	4,222

	2019			2018				2017
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Net earnings (loss)	1,420	1,531	(1,477)	5,431	1,184	(801)	(494)	(1,303)
Basic and Fully Diluted Earnings (loss) per share	0.01	0.01	(0.01)	0.02	0.01	(0.00)	(0.00)	(0.01)
Adjusted funds flow[(3)]	2,233	2,525	2,574	2,956	3,876	3,884	2,494	3,139
Bank debt	27,134	29,606	29,580	29,551	29,562	29,536	26,513	24,484
Total assets	161,598	163,185	163,118	164,559	160,752	159,428	157,320	150,789

(1) Netback from operations, netback including commodity contracts and netback are considered non-GAAP measures. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(2) Net operating income is considered a non-GAAP measure. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(3) Adjusted funds flow is considered a non-GAAP measure. Refer to the section entitled “Non-GAAP Measures” at the end of this MD&A.

(4) Prior period adjustments reflects adjustments for natural gas and NGL volumes sold and processing costs related to prior years due to the purchaser remeasuring prior volumes and reassessing prior gathering and processing costs.

Quarterly Variability

Fluctuations in quarterly results are due to a number of factors, some of which are not within the Company's control such as:

- Oil, gas and NGL price changes due to market conditions.
- Changes in production resulting from fluctuations in drilling and completions and shut-in of wells.
- Fluctuations in the U.S. dollar against the Canadian dollar result in higher or lower general and administrative expenses in United States dollar terms. The fluctuations also affect the net proceeds in United States dollar terms from equity issuances.
- The changes in G&A from quarter to quarter reflect changes in operations, changes in personnel, and non-recurring charges related to specific transactions or events.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the condensed consolidated interim financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities, the disclosures of contingencies at the date of the condensed consolidated interim financial statements and the reported amounts of revenues and expenses during the year. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts. Significant estimates and judgments made by management in the preparation of these condensed consolidated interim financial statements are as follows:

<u>Oil and gas assets</u>

Development and production assets are assessed for recoverability at cash generating unit ("CGU") level. The determination of CGUs is subject to management judgments. Recoverability is assessed by comparing the carrying value of the asset to its recoverable amount, which is based on the higher of fair value of the assets less the cost to sell ("FVLCS") or value in use ("VIU"). The key estimates used in the determination of the recoverable amount include the following:

- Reserves – Assumptions that are valid at the time of reserve estimation may change significantly when additional information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in a restatement of reserves.

- Oil and gas prices – Forward price estimates are used in the cash flow model. Commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather and economic and political factors.

- Discount rate – The discount rate used to calculate the net present value of cash flows is based on estimates of an industry peer group weighted average cost of capital. Changes in the economic environment could result in significant changes to this estimate.

<u>Depletion of oil and gas assets</u>

Depletion of oil and gas assets is determined based on total proved and probable reserve values and includes future development costs as estimated by the Company's external reserve evaluator. Amounts recorded for depletion and depreciation are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.

Asset retirement obligations

The provisions for site restoration and abandonment is based on current legal requirements, technology, price levels and expected plans and are based on significant assumptions such as inflation rate and discount rate. Actual costs and cash outflows can differ from estimates because of changes in laws or regulations, market conditions and changes in technology.

Derivative instruments

The estimated fair value of derivative financial instruments resulting in financial assets and liabilities, by their very nature is subject to estimation, due to the use of future oil and natural gas prices and the volatility in these prices.

Compensation costs

Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as Black-Scholes model which is based on assumptions such as volatility, forfeiture rate, interest rate and expected term.

Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such income taxes are subject to measurement uncertainty. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

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OUTSTANDING SHARE DATA

There were 232,922,625 and 232,922,625 common shares outstanding as at November 7, 2019 and September 30, 2019 respectively. The Company had 8,967,500 and 8,967,500 stock options outstanding as of November 7, 2019 and September 30, 2019, respectively.

PRINCIPAL BUSINESS RISKS

BNK's business and results of operations are subject to a number of risks and uncertainties, including but not limited to the following:

- the uncertainty of finding oil and gas in commercial quantities
- securing markets for existing and future production
- commodity price fluctuations due to market forces
- financial risk due to foreign exchange rates and interest rate exposure
- changes to government regulations in the United States, including regulations relating to prices, taxes, royalties and environmental protection
- changing government policies and regulations, social instability and other political, economic or diplomatic developments in the countries in which the Company operates
- the ability to fund wells drilled in non-operated sections of the Tishomingo field
- the uncertainty of pipeline repairs leading to temporary shutting-in wells
- availability of equity or debt financing is affected by many factors many of which are beyond the control of the Company
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom

- the oil and gas industry is intensely competitive and the Company competes with a large number of companies with greater resources
- risks related to the Credit Facility, including the risk that the Company could be required under the terms of the Credit Facility to prepay the outstanding principal amount and other amounts owing under the Credit Facility in certain circumstances, some of which are out of the Company's control, including failure to comply with financial ratio tests, borrowing base redeterminations, Mr. Wolf Regener ceasing to be the President of BNK Petroleum (US) Inc., certain changes to the board of directors of the Company and the acquisition by any person or persons acting jointly or in concert of 25% or more of the Company's shares. The Company is required to repay amounts owing under the Credit Facility in full on the June 2022 maturity date. There can be no assurance that the Company will be able to obtain sufficient capital to repay the Credit Facility or that the Company will be able to extend or refinance the Credit Facility. A failure by the Company to perform its obligations under the Credit Facility could result in, among other adverse effects, the loss of the Company's Tishomingo Field assets. A copy of the Amended and Restated Credit Agreement was filed on SEDAR on June 26, 2017. See "Liquidity and Capital Resources" and "Contractual Obligations" above and the "Risk Factors" section in the Company's most recent Annual Information Form.
- the other risks identified in the Company's most recent Annual Information Form under the "Risk Factors" section and the Company's other public disclosure, available under the Company's profile on SEDAR at www.sedar.com.

The Company seeks to mitigate these risks by:

- maintaining product mix to manage exposure to commodity price risk
- monitoring production trends to maximize the potential of its capital spending program
- from time to time, entering into financial commodity contracts to hedge against commodity price risk
- ensuring strong third-party operators for non-operated properties
- transacting with creditworthy counterparties
- monitoring commodity prices and capital programs to manage cash flow
- reviewing proposed changes in applicable government regulations and laws to assess the impact on the Company's operations

DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with IFRS.

The DC&P have been designed to provide reasonable assurance that material information relating to BNK is made known to the CEO and CFO by others and that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by BNK under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Company's CEO and CFO have concluded, based on their evaluation, that the Company's disclosure controls and procedures and ICOFR are effective to provide reasonable assurance that material information related to the Company, is made known to them by others within the Company.

The CEO and CFO are required to cause the Company to disclose any change in the Company's ICOFR that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's ICOFR. No changes in ICOFR were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's ICOFR. There were no changes to ICOFR during the quarter ended September 30, 2019.

It should be noted that a control system, including the Company's DC&P and ICOFR, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system will be met and it should not be expected that DC&P and ICOFR will prevent all errors or fraud.

OUTLOOK

In the United States, the Company intends to drill and complete additional wells in the Caney/Sycamore formations on its Oklahoma lands under which it has reserves forecast to be recoverable from a total of 112 drilling locations (52 proved undeveloped locations and 60 probable undeveloped locations) and additional possible locations per the Company's December 31, 2018 Form 51-101F1 Statement of Reserves Data and Other Oil and Gas Information filed on www.sedar.com. The Company continues to work on identifying additional basins that it believes are prospective for shale oil and gas as well. The Company's capital expenditures will be based on existing cash flow but could change with other potential sources of cash flow including proceeds from additional debt or equity offerings.

NON-GAAP MEASURES

Netback from operations, netback including commodity contracts, netback per barrel, net operating income and adjusted funds flow (collectively, the "Company's Non-GAAP Measures") are not measures recognized under Canadian generally accepted accounting principles ("GAAP") and do not have any standardized meanings prescribed by GAAP. Management of the Company believes that such measures are relevant for evaluating returns on each of the Company's projects as well as the performance of the enterprise as a whole. The Company's Non-GAAP Measures may differ from similar computations as reported by other similar organizations and, accordingly, may not be comparable to similar non-GAAP measures as reported by such organizations. The Company's Non-GAAP Measures should not be construed as alternatives to net income, cash flows related to operating activities, working capital or other financial measures determined in accordance with GAAP, as an indicator of the Company's performance.

Netback from operations per barrel and its components are calculated by dividing revenue, less royalties and operating expenses by the Company's sales volume during the period. Netback including commodity contracts are calculated by adjusting netback from operations by the realized gains or losses received from commodity contracts during the period. Netback with adjustments are calculated by adjusting netback including commodity contracts by the net impact of the prior period adjustments related to revenue and operating expenses and sales volumes. Netback per barrel is a non-GAAP measure but it is commonly used by oil and gas companies to illustrate the unit contribution of each barrel produced. The Company believes that netback per barrel is a useful supplemental measure of the cash flow generated on each barrel of oil equivalent that is produced in its operations. However, non-GAAP measures do not have any standardized meaning prescribed by GAAP and therefore, may not be comparable to similar measures used by other companies and should not be used to make comparisons.

The following is the reconciliation of the non-GAAP measure netback from operations to net income (loss) from continuing operations:

(US $000)	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
Net income (loss)	**1,420**	1,184	**1,474**	(111)
Adjustments:				
Finance income	**(1,263)**	-	**(597)**	-
Finance expense	**644**	1,561	**2,199**	5,876
Stock based compensation	**27**	57	**121**	279
General and administrative expenses	**811**	885	**2,548**	2,822
Depletion, depreciation and amortization	**1,531**	1,879	**4,731**	6,174
Other income	**-**	-	**(2)**	(19)
Operating netback	**3,170**	5,566	**10,474**	15,021
Netback from operations per BOE	**27.47**	38.33	**27.47**	35.39

Net operating income is similarly a non-GAAP measure that represents revenue net of royalties and operating expenses. The Company believes that net operating income is a useful supplemental measure to analyze operating performance and provides an indication of the results generated by the Company's principal business activities prior to the consideration of other income and expenses.

The following is the reconciliation of the non-GAAP measure net operating income:

(US $000)	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
Oil and gas revenue, net of royalties	**4,104**	6,854	**13,282**	18,632
Operating expenses	**934**	1,268	**2,808**	3,611
Net operating income	**3,170**	5,586	**10,474**	15,021

Adjusted funds flow is calculated as cash from operating activities excluding changes in non-cash operating working capital and interest expense. The Company considers this a key measure as it demonstrates its ability to generate funds from operations necessary for future growth excluding the impact from short-term fluctuations in the collection of accounts receivable and the payment of accounts payable and financing costs. The following is the reconciliation of the non-GAAP measure adjusted funds flow:

(US $000)	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	**2019**	2018
Cash flow from continuing operations	**1,986**	3,434	**5,902**	9,264
Change in non-cash working capital	**(227)**	(48)	**(39)**	(367)
Interest expense[(a)]	**474**	489	**1,469**	1,356
Adjusted funds flow	**2,233**	3,875	**7,332**	10,253

(a) Interest expense on long-term debt excluding the amortization of debt issuance costs

NEW ACCOUNTING STANDARDS

In January 2016, the IASB issued the complete IFRS 16 Leases ("IFRS 16") which replaces IAS 17, Leases. Under IFRS 16, a single recognition and measurement model applies for lessees which requires recognition of a right of use asset and lease liabilities for most lease contracts. The Company has adopted IFRS 16 on January 1, 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period information as it applies the standard prospectively. Accordingly, comparative information in these financial statements is not restated. On adoption, lease liabilities were measured at the present value of the remaining lease payments discounted at the Company's incremental borrowing rate at January 1, 2019. Right of use assets were measured at an amount equal to the lease liability.

CAUTIONARY STATEMENTS

(a) The Company's natural gas production is reported in thousands of cubic feet ("Mcfs"). The Company also uses references to barrels ("Bbls") and barrels of oil equivalent ("BOEs") to reflect natural gas liquids and oil production and sales. 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.

(b) Discounted and undiscounted net present value of future net revenues attributable to reserves do not represent fair market value.

(c) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(d) This MD&A and the Company's other public disclosure contains peak and 30-day initial production rates and other short-term production rates. Readers are cautioned that initial production rates are preliminary in nature and are not necessarily indicative of long-term performance or of ultimate recovery.

CAUTION REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains forward-looking information including expectations regarding the Company's reserve-based loan facility, proposed timing and expected results of exploratory and development work in the Company's Tishomingo Field, expected productivity from current and future wells, planned capital expenditure programs and cost estimates, the effect of design and performance improvements on future productivity, planned use and sufficiency of proceeds from the Company's debt and equity financings, cash on hand and cash flow from operations and the Company's strategy and objectives. The use of any of the words "target", "plans", "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements.

Such forward-looking information is based on management's expectations and assumptions, including that the Company's geologic and reservoir models and analysis will be validated, that indications of early results are reasonably accurate predictors of the prospectiveness of the shale intervals, that previous exploration results are indicative of future results and success, that expected production from future wells can be achieved as modeled, declines will match the modeling, future well production rates will be improved over existing wells, that rates of return as modeled can be achieved, that recoveries are consistent with management's expectations, that additional wells are actually drilled and completed, that design and performance improvements will reduce development time and expense and improve productivity, that discoveries will prove to be economic, that well shut-ins will not materially reduce production or adversely affect future productivity, that anticipated results and estimated costs will be consistent with managements' expectations, that all required permits and approvals and the necessary labor and equipment will be obtained, provided or available, as applicable, on terms that are acceptable to the Company, when required, that no unforeseen delays, unexpected geological or other effects, equipment failures, permitting delays or labor or contract disputes are encountered, that the development plans of the Company and its co-venturers will not change, that the demand for oil and gas will be sustained, that the combination of cash on hand and cash flow from operations will be sufficient to finance the Company's cash requirements through 2019, that the Company will continue to be able to access sufficient capital through financings, credit facilities, farm-ins or other participation arrangements to maintain its projects, that the Company will continue in compliance with the covenants under its reserve-based loan facility and that the borrowing base will not be reduced, that the Company will not be adversely affected by changing government policies and regulations, social instability or other political, economic or diplomatic developments in the countries in which it operates and that global economic conditions will not deteriorate in a manner that has an adverse impact on the Company's business and its ability to advance its business strategy.

Forward looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: any of the assumptions on which such forward looking information is based vary or prove to be invalid, including that the Company's geologic and reservoir models or analysis are not validated, anticipated results and estimated costs will not be consistent with managements' expectations, that the Company will not achieve a comparable level of hedging going forward in respect of its existing production, that the Company will not achieve the results anticipated by management from the Company's cost reduction measures, the risks associated with the oil and gas industry (e.g. operational risks in development, exploration and production; delays or changes in plans with respect to exploration and development projects or capital expenditures; the uncertainty of reserve and resource estimates and projections relating to production, costs and expenses, and health, safety and environmental risks, including flooding and extended interruptions due to inclement or hazardous weather conditions), well shut-ins and the potential for damage to the affected wells, the risk of commodity price and foreign exchange rate fluctuations, risks and uncertainties associated with securing the necessary regulatory approvals and financing to proceed with continued development of the Tishomingo Field, the Company or its subsidiaries is not able for any reason to obtain and provide the information necessary to secure required approvals or that required regulatory approvals are otherwise not available when required, that unexpected geological results are encountered, that completion techniques require further optimization, that production rates do not match the Company's assumptions, that very low or no production rates are achieved, that the Company will cease to be in compliance with the covenants under its reserve-based loan facility and be required to repay outstanding amounts or that the borrowing base will be reduced pursuant to a borrowing base redetermination and the Company will be required to repay the resulting shortfall, that the Company is unable to access required capital, that occurrences such as those that are assumed will not occur, do in fact occur, and those conditions that are assumed will continue or improve, do not continue or improve and the other risks identified in the Company's most recent Annual Information Form under the "Risk Factors" section and the Company's other public disclosure, available under the Company's profile on SEDAR at www.sedar.com.

Although the Company has attempted to take into account important factors that could cause actual costs or results to differ materially, there may be other factors that cause actual results not to be as anticipated, estimated or intended. There can be no assurance that such statements will prove to be accurate as actual results and future events could differ materially from those anticipated in such statements. The forward-looking information included in this MD&A is expressly qualified in its entirety by this cautionary statement. Accordingly, readers should not place undue reliance on forward-looking information. The Company undertakes no obligation to update these forward-looking statements, other than as required by applicable law.

CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Ford Nicholson [2,3,5]
Director, Chairman of the Board

Victor Redekop [1,2,4]
Director

Eric Brown [1,2,3]
Director

General Wesley K. Clark [4]
Director

Leslie O'Connor [5]
Director

David Neuhauser [1,3,5]
Director

Wolf Regener [4]
Director, President and Chief Executive Officer

Gary Johnson
Chief Financial Officer and Vice President

1 Member of the Audit Committee
2 Member of the Corporate Governance Committee
3 Member of the Compensation Committee
4 Member of the HS&E Committee
5 Member of the Reserves Committee

STOCK EXCHANGE LISTING
The Toronto Stock Exchange
Trading Symbol: BKX
(Over the Counter OTC) QX
Trading Symbol: BNKPF

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