MANAGEMENT’S DISCUSSION AND ANALYSIS

MARCH 31, 2016

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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 ended March 31, 2016, compared to the corresponding period 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 interim condensed financial statements for the three months ended March 31, 2016 and the audited consolidated financial statements and MD&A for the year ended December 31, 2015. The interim consolidated 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, 2015. 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 on the Company's website at www.bnkpetroleum.com.

This report is prepared as of May 5, 2016. 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, predominately 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".

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 March 31, 2016	2015
Financial (US $000 except per share)		
Oil and gas gross revenues	**2,668**	4,117
Net operating income[2]	**1,512**	2,619
Net loss	**(1,250)**	(760)
Basic and diluted net loss per share	**(0.01)**	0.00
Cash flow from continuing operations	**1,524**	1,916
Additions to property, plant and equipment	**131**	4,313
Additions to exploration and evaluation assets	**-**	5
Operating		
Average production (Boepd)	**1,352**	1,249
Average price ($/BOE)	**21.69**	36.62
Netbacks ($/BOE)[1]	**12.29**	23.33
Netbacks including commodity contracts ($/BOE) [1]	**25.89**	31.08

	March 2016	December 2015
Balance Sheet		
Cash and cash equivalents	**2,885**	1,666
Total assets	**148,533**	149,806
Working capital	**7,950**	7,298
Total non-current liabilities	**24,726**	24,749

(1) Netbacks is considered a non-GAAP measure. 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.

Highlights

Average production for the first quarter of 2016 was 1,352 BOEPD, an increase of 8% compared to the first quarter of 2015 production of 1,249 BOEPD. This was primarily due to the completion of the fracture stimulation operations on the previously drilled Nickel Hill 36-3H well and the Emery 17-1H well in the second quarter of 2015.

Gross revenues for the first quarter of 2016 decreased by 35% compared to 2015. Cash flow from continuing operations was $1.5 million for the first quarter of 2016 compared to $1.9 million in 2015. The decrease in revenues and cash flow from continuing operations was primarily due to the 34% decrease in oil prices in 2016 compared to 2015.

Due to the Company's continuing cost cutting efforts, general & administrative expenses decreased by 31% for the first quarter of 2016 and operating expenses on a per barrel basis decreased by 11% for the quarter compared to the same quarter in 2015.

Netbacks(1) decreased from $23.33 in the first quarter of 2015 to $12.29 in 2016, a decrease of 47%. The decrease was due to the average price per BOE decreasing 41% in the first quarter of 2016 compared to the same period in the prior year.

Over 70% of first quarter 2016 oil production was hedged which resulted in substantially higher netbacks. Netbacks including commodity contracts(1) decreased from $31.08 to $25.89, a decrease of 17%.

Net loss for the first quarter of 2016 was $1.3 million compared to net loss of $0.8 million in the first quarter of 2015.

Cash and cash equivalents was $2.9 million at March 31, 2016, an increase of 73% from December 31, 2015. Working capital at March 31, 2016 was $8.0 million, an increase of 9% from December 31, 2015.

In April 2016, subsequent to the end of the quarter, the Company made a voluntary $1.8 million pay down on the credit facility to reduce the outstanding balance on the credit facility to $22.6 million.

(1) Netback is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

OPERATIONS UPDATE

Tishomingo Field, Ardmore Basin, Oklahoma

The average production for the first quarter of 2016 was 1,352 BOEPD, an increase of 8% compared to first quarter 2015 production of 1,249 BOEPD. Production during the current quarter increased as compared to the same quarter in 2015 due to the fracture stimulation operations on the previously drilled Nickel Hill 36-3H well and the Emery 17-1H well in the second half of 2015.

Spain

The Company continues to wait on the Spanish administration which is conducting its technical review of the previously submitted Environmental Impact Assessments (EIAs) to drill up to six wells in the Sedano concession and up to six wells in the Urraca concession. The Company holds a 100% interest in both concessions through its wholly owned subsidiary, BNK Sedano Hidrocarburos ("BNK Spain").

BNK Spain withdrew its application for the Rojas concession in Spain, which is adjacent to the Urraca and Sedano concessions.

The Company is evaluating alternatives for Spain including continuing its efforts to obtain a partner or a reduction or cessation of operations.

Poland

In February 2016, the Company decided to shut down all operations in Poland and started the process of relinquishing the Slupsk concession, which was its last remaining concession in Poland. The Company plans to either liquidate or sell its remaining entities in Poland and has reclassified all of the Poland operations to discontinued operations.

DISCUSSION OF OPERATING RESULTS

Production and Revenue

	Three months ended March 31		
	2016	2015	%
Average oil production (Bopd)	**744**	867	(14)
Average natural gas production (mcf/d)	**1,702**	1,397	22
Average NGL production (Boepd)	**324**	149	117
Average production (Boepd)	**1,352**	1,249	8
Average oil price ($/bbl)	**30.24**	46.13	(34)
Average natural gas price ($/mcf)	**1.93**	2.97	(35)
Average NGL price ($/bbl)	**10.96**	10.68	3
Average price ($/BOE)	**21.69**	36.62	(41)
Oil revenue ($000)	**2,047**	3,600	(43)
Natural gas revenue ($000)	**299**	374	(20)
NGL revenue ($000)	**323**	143	126

Oil production for the first quarter was 744 bopd compared to 867 bopd for the same period in 2015 a decrease of 14%. The production decrease is due to natural production declines. Oil revenue decreased by 43% in the first quarter 2016 versus the comparable period in 2015 due to a 34% decrease in oil prices combined with the production decrease.

During the first quarter 2016, average natural gas production was 1,702 mcfpd compared to 1,397 mcfpd for the same quarter in 2015, an increase of 22%. The increase in natural gas production versus 2015 is due to the fracture stimulation operations of 2 wells in the second half of 2015. Natural gas revenue decreased by 20% in the first quarter 2016 versus the comparable period in 2015 due to a 35% decrease in natural gas prices, which was partially offset by the production increase.

Natural Gas Liquids ("NGL") production in the first quarter of 2016 increased to 324 boepd from 149 boepd in the comparable period in 2015, an increase of 117%. The production increase is due to the fracture stimulation operations of 2 wells in the second half of 2015 and a higher percentage of NGLs being extracted from gas production during processing. The production increase, combined with a 3% increase in NGL prices in the first quarter of 2016 compared to the first quarter 2015, increased NGL revenue by 126% between the two periods.

Production on a per boe basis was 1,352 boepd in the first quarter of 2016 compared to 1,249 boepd in the comparable period in 2015, an increase of 8%. This increase is due to a combination of the factors discussed above. Gross revenue in the first quarter of 2016 decreased by 35% compared to the first quarter of 2015 due to a 41% decrease in average prices, partially offset by the production increases in natural gas and NGLs.

Royalties, Operating Expenses and Netbacks[1]

	Three months ended March 31		
($/BOE)	**2016**	**2015**	**%**
Average price	**21.69**	36.62	(41)
Royalties	**4.91**	8.24	(40)
Operating expenses	**4.49**	5.05	(11)
Netbacks[1]	**12.29**	23.33	(47)

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

The average price decrease for 2016 was due to significant price decreases in oil and natural gas. Oil made up 55% of the production mix in 2016 compared to 69% oil in the production mix for 2015. The decrease of oil in the production mix is primarily due to the Nickel Hill 36-3H well and the T-zone wells which have a higher gas to oil ratio than the Caney zone wells and, in addition, the Company was allocated higher NGL yields in the first quarter of 2016 compared to first quarter in the prior year.

Royalties on Tishomingo production averaged approximately 22.6% for 2016 versus 22.5% in 2015.

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 first quarter of 2016 were $552,000 compared to $572,000 in 2015. Operating expenses averaged $4.49 per boe for the first quarter of 2016 compared to $5.05 per boe for the same period in 2015. The per barrel operating expense decrease of 11% for 2016 reflects the Company’s continued cost cutting efforts.

Realized and Unrealized Gains and Losses from Risk Management Contracts

In 2014 and 2015, 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 March 31, 2016 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	April 1, 2016 to December 31, 2016	25,800	$89.90
Oil - WTI	April 1, 2016 to December 31, 2016	100,106	$60.13
Oil – WTI	January 1, 2017 to June 30, 2017	14,500	$87.65
Oil - WTI	January 1, 2017 to December 31, 2017	117,952	$60.13
Oil - WTI	January 1, 2018 to January 31, 2018	8,818	$60.13
Oil - WTI	January 1, 2018 to December 31, 2018	89,892	$54.70
Gas - Henry Hub	April 1, 2016 to December 31, 2016	114,109	$3.06
Gas - Henry Hub	April 1, 2016 to December 31, 2016	44,784	$2.475
Gas - Henry Hub	January 1, 2017 to December 31, 2017	119,993	$3.06
Gas - Henry Hub	January 1, 2017 to December 31, 2017	46,824	$2.80
Gas - Henry Hub	January 1, 2018 to January 31, 2018	7,983	$3.06
Gas - Henry Hub	January 1, 2018 to December 31, 2018	116,772	$2.90

The estimated fair value of $6.5 million as at March, 2016 for the financial oil and gas contracts has been determined based on the prospective amounts that the Company would receive or pay to terminate the contracts.

If the realized gains from these outstanding commodity contracts were included in the average price computation, the Company’s netbacks(1) would be as follows:

Netbacks including Commodity Contracts [(1)]

	Three months ended March 31		
($/BOE)	**2016**	**2015**	**%**
Average price including commodity contracts	**35.29**	44.37	(20)
Royalties	**4.91**	8.24	(40)
Operating expenses	**4.49**	5.05	(11)
Netbacks including commodity contracts[(1)]	**25.89**	31.08	(17)

(1) Netbacks including Commodity Contracts is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

General and Administrative Expenses

General and administrative expenses (G&A) for the quarter were $1.4 million compared to $2.0 million for the same period of 2015. The decrease in G&A compared to 2015 relates primarily to the Company's efforts to reduce costs which included salary and benefit costs and legal, accounting and consulting fees.

Depletion and Depreciation

Depletion and depreciation expense for the first quarter of 2016 was $1,671,000 compared to $1,811,000 in the same period of 2015. Depletion and depreciation expense on a per barrel basis was $13.58 for the quarter compared to $16.11 in the first quarter of 2015.

Stock based compensation

Stock based compensation decreased from $180,000 for the first quarter of 2015 to $42,000 in the first quarter of 2016. This decrease was due to the timing of stock awards granted to employees.

Interest on loans and borrowings

Interest on loans and borrowings increased from $459,000 for the first quarter 2015 to $527,000 for the first quarter of 2016. This increase is due to the Company's $8.5 million of additional borrowings in February 2015 on the credit facility with Morgan Stanley Capital Group Inc. which increased the total borrowings to $24.4 million.

Net loss for the period and cash from operating activities

The Company incurred net loss of $1,250,000 ($0.01 per share) for the first quarter of 2016 compared to a net loss of $760,000 ($0.00 per share) for the same period of 2015. The increase in net loss compared to the same period in 2015 is due to a decrease in net revenue of $1,127,000, a gain in financial commodity contracts in the first quarter of 2016 of $881,000 versus a gain of $2,043,000 in the first quarter of 2015, partially offset by a loss from discontinued operations of $3,000 in 2016 versus a loss of $657,000 in 2015, a decrease in general and administrative costs of $637,000, a foreign exchange gain of $7,000 in 2016 versus a loss of $246,000 in 2015, a decrease in depletion, depreciation and accretion of $140,000 and a decrease of $138,000 in stock based compensation.

Cash flows from operating activities for the first quarter 2016 was $1,544,000 compared to cash flows from operating activities of $1,282,000 for the same period in 2015.

CAPITAL EXPENDITURES

($000, except as noted)

	Three months ended March 31	
	2016	2015
Additions to oil and gas properties	**$ 131**	$ 4,313
Additions to exploration and evaluation	**-**	5
	$ 131	$ 4,318

In the first quarter of 2016, the Company spent approximately $0.1 million in the U.S.

LIQUIDITY AND CAPITAL RESOURCES

($000, except as noted)	**At March 31,**	
	2016	**2015**
Working Capital (US$)	**$ 7,950**	$ **6,827**
Loans and Borrowings (US$)	**$ 24,400**	$ **24,400**
Shares Outstanding, end of period	**162,689,292**	**162,689,292**
Market Price per share, end of period (in Canadian $)	**$ 0.36**	**$ 0.56**
Market Value of Shares (in Canadian $)	**$ 58,568,145**	**$ 91,106,004**

In July 2014, the Company's US subsidiary obtained a new $100 million credit facility from Morgan Stanley Capital Group Inc. ("Morgan Stanley"), which is secured by the US subsidiary's interests in the Tishomingo Field. The credit facility has an initial commitment amount of $15.9 million and is intended to fund the drilling of Caney wells in the Tishomingo Field. The facility bears interest at a per annum rate equal to then three month LIBOR plus an applicable margin ranging from 2% to 7% based on a number of factors including the ratio of outstanding borrowings to a calculated borrowing base level and individual well value concentration. The facility provides for interest only payments until the July 2018 maturity date. Additional commitment amounts will be subject to new reserve evaluations. In February 2015, the US subsidiary borrowed an additional $8.5 million on the credit facility. Primary debt covenants of the facility require the US subsidiary to maintain a positive working capital balance, to insure the ratio of outstanding debt to an adjusted EBITDA amount be no greater than 4 to 1 at any quarter end and to insure the ratio of adjusted EBITDA to interest expense be no less than 2.5 at any quarter end. At March 31, 2016, the Company was in compliance with all of these covenants. At March 31, 2016 loans and borrowings of $24.4 million (December 31, 2015: $24.4 million) are presented net of loan acquisition costs of $0.4 million (December 31, 2015: $0.4 million). In April 2016, subsequent to the end of the quarter, the Company made a voluntary $1.8 million pay down on the credit facility to reduce the outstanding balance on the credit facility to $22.6 million.

At March 31, 2016 the Company had net working capital of $8.0 million versus $6.8 million at March 31, 2015. The Company closely monitors its working capital and borrowing capacity to insure adequate funds are available to finance both US and European administrative and operating requirements.

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 that have occurred over the past year. The Company believes that the combination of cash on hand, cash flow from operations, borrowings from its credit facility and/or other equity or debt financings will be sufficient to finance the Company's cash requirements through 2016. Other potential sources of cash flow include proceeds from individual concession sales and additional debt or equity offerings.

CONTRACTUAL OBLIGATIONS

The following are the contractual maturities of financial liabilities, excluding estimated interest payments at March 31, 2016:

	Total	2016	2017	2018
Loans and borrowings *	(24,400)	-	-	(24,400)
Trade and other payables	(2,587)	(2,587)	-	-
	(26,987)	(2,587)	0	(24,400)

* See "Liquidity and Capital Resources" and "Principal Business Risks" for discussion of events that would require early repayment of the credit facility.

COMMITMENTS

Poland

Slupsk Concession - Saponis Investments Sp. z o.o.

In February 2016, the Company filed the paperwork necessary to relinquish the Slupsk concession.

Spain

The Sedano and Urraca concession applications outlined the annual work programs in each year of the four and five year concession terms, respectively, including the drilling of a total of nine wells on each concession. However, the concession applications stipulated that failure to drill the required wells in the time indicated in the concession applications would not constitute a default of the concession requirements if required permits are not approved by the government in a timely fashion.

BNK Spain is required annually to submit a current year work program for each concession. Each work program reflects the progression of the project, including in respect of permitting.

As a result of permitting delays, BNK Spain submitted applications to suspend the Sedano and Urraca concession work programs. Approval of the application for Sedano was received during the third quarter of 2015 and approval of the Urraca application is still pending. The current year work programs are comprised of obtaining EIA and administrative approvals, obtaining drilling permits, continuing communications, and finalizing drilling programs. Well site construction is not expected to commence until at least 2017.

A failure to meet work commitments without obtaining an extension, suspension, or another arrangement may result in the loss of the applicable concession. The Company understands that there may be circumstances in which a failure to meet work commitments could result in liability in regard to the unperformed current year work commitments. The Company is evaluating alternatives for Spain including continuing its efforts to obtain a partner or a reduction or cessation of operations.

QUARTERLY SUMMARY

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

	2016	2015		
($000, except as noted)	**Q1**	**Q4**	**Q3**	**Q2**
Daily Production				
Oil (bpd)	744	832	904	914
Natural gas (mcfpd)	1,702	1,436	1,799	1,637
NGL's (bpd)	324	296	350	303
Average production (boepd)	1,352	1,367	1,554	1,490

	2015	2014		
($000, except as noted)	**Q1**	**Q4**	**Q3**	**Q2**
Daily Production				
Oil (bpd)	867	910	673	722
Natural gas (mcfpd)	1,397	1,182	1,024	822
NGL's (bpd)	149	173	127	140
Average production (boepd)	1,249	1,280	971	999

	2016	2015		
($000, except as noted)	**Q1**	**Q4**	**Q3**	**Q2**
Average Price				
Oil ($/bbl)	30.24	39.36	44.41	54.35
Natural gas ($/mcf)	1.93	1.89	2.54	2.38
NGL ($/bbl)	10.96	13.54	12.78	16.72
Average price ($/bbl)	21.69	28.86	31.65	39.35

	2015	2014		
($000, except as noted)	**Q1**	**Q4**	**Q3**	**Q2**
Average Price				
Oil ($/bbl)	46.13	72.11	96.6	101.93
Natural gas ($/mcf)	2.97	3.53	3.72	4.48
NGL ($/bbl)	10.68	24.55	30.32	31.28
Average price ($/bbl)	36.62	57.82	74.80	81.74

($000, except as noted)	2016 Q1	2015 Q4	2015 Q3	2015 Q2
Netback[(1)]				
Average price ($/boe)	21.69	28.86	31.65	39.35
Royalties	4.91	6.57	7.39	9.51
Operating expenses	4.49	5.19	5.02	4.96
Netback ($/boe)	12.29	17.10	19.24	24.88

($000, except as noted)	2015 Q1	2014 Q4	2014 Q3	2014 Q2
Netback[(1)]				
Average price ($/boe)	36.62	57.82	74.80	81.74
Royalties	8.24	10.84	14.02	15.33
Operating expenses	5.05	5.38	8.64	7.56
Netback ($/boe)	23.33	41.60	52.14	58.85

($000, except as noted)	2016 Q1	2015 Q4	2015 Q3	2015 Q2
Net operating income[(2)]				
Oil and gas revenue	2,669	3,834	4,525	5,335
Royalties	604	826	1,056	1,290
Operating expenses	552	653	717	672
	1,513	2,355	2,752	3,373

($000, except as noted)	2015 Q1	2014 Q4	2014 Q3	2014 Q2
Net operating income[(2)]				
Oil and gas revenue	4,117	6,809	6,682	7,432
Royalties	926	1,277	1,253	1,394
Operating expenses	568	634	772	687
	2,623	4,898	4,657	5,351

($000, except as noted)	2016 Q1	2015 Q4	2015 Q3	2015 Q2
Net earnings (loss)	(1,250)	(6,348)	4,197	(3,658)
Basic and Fully Diluted Earnings (loss) per share	(0.01)	(0.04)	0.03	(0.02)
Funds from operations(3)	1,544	960	1,693	1,779
Bank debt	24,400	24,400	24,400	24,400
Total assets	148,533	149,806	158,514	157,456

($000, except as noted)	2015 Q1	2014 Q4	2014 Q3	2014 Q2
Net earnings (loss)	(760)	(57,628)	(299)	199
Basic and Fully Diluted Earnings (loss) per share	0.00	(0.36)	0.00	0.00
Funds from operations(3)	1,282	3,651	1,850	2,808
Bank debt	24,400	15,401	15,420	100
Total assets	161,377	163,429	222,285	207,415

(1) Netback is considered a non-GAAP measure. 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) Funds from operations is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

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
- Fluctuations in the U.S. dollar against Canadian dollar, Euro and Polish Zlotys 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 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 consolidated 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 consolidated financial statements are as follows:

Oil and gas assets

Development and production assets are assessed for recoverability at a 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.

Depletion of oil and gas assets

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.

OUTSTANDING SHARE DATA

There were 162,689,292, 162,689,292 and 162,689,292 common shares outstanding as at May 5, 2016, March 31, 2016 and March 31, 2015 respectively. The Company had 11,350,833, 8,584,166 and 10,198,666 stock options outstanding as of May 5, 2016, March 31, 2016 and March 31, 2015, 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
- commencing operations and meeting concession requirements in our European locations
- 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
- 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 Company's 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 facility in certain circumstances, some of which are out of the Company's control, including in the event that Mr. Wolf Regener ceases to be the President of BNK Petroleum (US) Inc. and certain changes to the board of directors of the Company. 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 August 11, 2014.
- 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 government regulations and laws in the United States and Europe 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 Issuer’s 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 issuer, 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 year.

It should be noted 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. The Company continues to work on identifying additional basins that it believes are prospective for shale oil and gas as well.

NON-GAAP MEASURES

Netback per barrel, net operating income and funds from operations (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 per barrel and its components are calculated by dividing revenue, less royalties and operating expenses by the Company's sales volume during the period. Netbacks including Commodity Contracts and its components are calculated by dividing revenue and realized gains from commodity contracts, less royalties and operating expenses by the Company's sales volume during the period. 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. 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.

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.

Funds from operations is calculated as cash from operating activities before change in non-cash operating working capital. The Company considers this a key measure as it demonstrates its ability to generate the funds necessary for future growth after taking into account the short-term fluctuations in the collection of accounts receivable and the payment for accounts payable.

NEW ACCOUNTING STANDARDS

The IASB issued IFRS 9, "Financial Instruments", which is the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial asset and liabilities with a single model that has only two classification categories: amortized cost and fair value. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company is currently evaluating the impact of adopting this new standard.

In May 2014, the IASB published IFRS 15 "Revenue from Contracts with Customers," to replace IAS 18 "Revenue," which establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company is currently evaluating the impact of adopting this new standard.

In January 2016, the IASB issued the complete IFRS 16 Leases ("IFRS 16") which replaces IAS 17, Leases. The effective date of IFRS 16 is for annual periods beginning on or after January 1, 2019 and early adoption is permitted. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The extent of the impact of adoption of the standard has not yet been determined.

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 information regarding the proposed timing and expected results of exploratory and development work including production from the Lower Caney and upper Sycamore formations on the Company's Oklahoma acreage, the effect of design and performance improvements on future productivity, the anticipated timing of commencement and completion of drilling and fracture-stimulations in connection with the Company's Caney drilling program, the advancement of the Company's European projects, including permit and concession applications and approvals, future well stimulations, and expected productivity from future wells, including expected results, planned capital expenditure programs and cost estimates, 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 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 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 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), 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 and other shale basins in the United States and Europe, 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 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 [3,5]
Director, Chairman of the Board

Robert Cross [1,2,3]
Director

Victor Redekop [1,2,4,5]
Director

Eric Brown [1,2,3]
Director

General Wesley K. Clark [4]
Director

Leslie O'Connor [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

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DuMoulin Black LLP
Vancouver, BC

AUDITORS
KPMG, LLP
Calgary, AB

BANKERS
Amegy Bank National Association
Denver, CO, USA

HSBC Bank Canada
Calgary, AB

Morgan Stanley
New York, NY

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