



**MANAGEMENT'S DISCUSSION AND ANALYSIS**

**JUNE 30, 2016**



## MANAGEMENT'S DISCUSSION AND ANALYSIS

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 and six months ended June 30, 2016, compared to the preceding quarter and 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 interim condensed financial statements for the three and six months ended June 30, 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](http://www.sedar.com) and on the Company's website at [www.bnkpetroleum.com](http://www.bnkpetroleum.com).

This report is prepared as of August 11, 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		Six Months ended	
	June 30,		June 30,	
	2016	2015	2016	2015
<b>Financial (US \$000 except as noted)</b>				
Oil and gas gross revenue	3,157	5,334	5,825	9,451
Net operating income <sup>(1)</sup>	1,872	3,372	3,384	5,991
Net loss	(5,310)	(3,658)	(6,560)	(4,418)
Basic and diluted net loss per share	(0.03)	(0.02)	(0.04)	(0.03)
Cash flow from continuing operations	1,587	1,914	3,111	3,830
Additions to property, plant and equipment	406	4,084	537	8,397
<b>Operating</b>				
Average production (Boepd)	1,149	1,490	1,250	1,369
Average price (\$/BOE)	30.19	39.35	25.61	38.15
Netback (\$/BOE) <sup>(2)</sup>	17.90	24.88	14.88	24.21
Netback including commodity contracts (\$/BOE) <sup>(2)</sup>	27.16	29.84	26.49	30.44
	<b>Jun-16</b>	<b>Mar-16</b>	<b>Dec-15</b>	
<b>Balance Sheet</b>				
Cash and cash equivalents	2,442	2,885	1,666	
Total assets	142,067	148,533	149,806	
Working capital	5,278	7,950	7,298	
Total non-current liabilities	23,446	24,726	24,749	

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

### Highlights

The average production for the second quarter of 2016 was 1,149 BOEPD, a decrease of 23% compared to second quarter 2015 production of 1,490 BOEPD. The average production for the six months ended June 30, 2016 was 1,250 BOEPD, a decrease of 9% compared to six months ended June 30, 2015 production of 1,369 BOEPD. The decreases were primarily due to the initial production volumes from completion of the fracture stimulation operations on the Nickel Hill 36-3H well and the Emery 17-1H well in the second quarter of 2015 and a prior period adjustment which decreased second quarter 2016 production.

Gross revenues for the second quarter 2016 decreased by 41% compared to the second quarter of 2015. Gross revenues for the six months ended June 30, 2016 decreased by 38% compared to the same period of 2015. Cash flow from continuing operations was \$1.6 million for the second quarter of 2016 compared to \$1.9 million in the second quarter of 2015. Cash flow from continuing operations was \$3.1 million for the six months ended June 30, 2016 compared to \$3.8 million in the same period of 2015. The decrease in revenues and cash flow from

continuing operations was due to the 23% decrease in average prices in the second quarter of 2016 and 33% in the six months ended June 30, 2016 compared to the same periods in 2015 and the decrease in average production that was discussed above.

Due to the Company's continuing cost cutting efforts, general & administrative expenses decreased by 29% in the second quarter of 2016 and 30% for the first six months of 2016 compared to the comparable prior year periods.

Netbacks<sup>(1)</sup> decreased from \$24.88 in the second quarter 2015 to \$17.90 in the second quarter of 2016, a decrease of 28%. Netbacks<sup>(1)</sup> decreased from \$24.21 in the first six months of 2015 to \$14.88 for the same period of 2016, a decrease of 39%. The decrease was due to the decrease in average prices during 2016.

Over 75% of 2016 oil production was hedged which resulted in substantially higher netbacks when the impact of the commodity hedges are included. Netbacks including commodity contracts<sup>(1)</sup> for the second quarter decreased from \$29.84 in 2015 to \$27.16 in 2016, a decrease of 9%. Netbacks including commodity contracts<sup>(1)</sup> for the first six months decreased from \$30.44 in 2015 to \$26.49 in 2016, a decrease of 13%.

Net loss for the second quarter 2016 was \$5.3 million compared to net loss of \$3.7 million in the second quarter of 2015. Net loss for the first six months of 2016 was \$6.6 million compared to net loss of \$4.4 million for the same period in 2015. The second quarter 2016 included an unrealized loss on financial commodity contracts of \$4.7 million as the average price of oil increased 40% from first quarter 2016 to the second quarter 2016.

The Company made a \$1.8 million paydown on the credit facility in April 2016 and an additional \$1.4 million paydown in July 2016, subsequent to the end of the quarter, which reduced the outstanding balance on the credit facility to \$21.2 million at July 31, 2016, with \$3.2 million available to borrow on the credit facility.

(1) Netback and netback including commodity contracts are considered non-GAAP measures. 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 second quarter of 2016 was 1,149 BOEPD, a decrease of 23% compared to the second quarter 2015 production of 1,490 BOEPD. The average production for the six months ended June 30, 2016 was 1,250 BOEPD, a decrease of 9% compared to the six months ended June 30, 2015 production of 1,369 BOEPD. The decreases were primarily due to the completion of the fracture stimulation operations on the Nickel Hill 36-3H well and the Emery 17-1H well in the second quarter of 2015 and a prior period adjustment which decreased second quarter 2016 production.

### **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 Urraca concession. The Company holds a 100% interest in this concession through its wholly owned subsidiary, BNK Sedano Hidrocarburos ("BNK Spain").

BNK Spain has submitted documents with the government to relinquish the Sedano concession and has withdrawn its application for the Rojas concession in Spain.

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

## DISCUSSION OF OPERATING RESULTS

### Production and Revenue

	Three months ended June 30			Six months ended June 30		
	2016	2015	%	2016	2015	%
Average oil production (Bopd)	<b>672</b>	914	(26)	<b>708</b>	890	(20)
Average natural gas production (mcf/d)	<b>1,181</b>	1,637	(28)	<b>1,441</b>	1,518	(5)
Average NGL production (Boepd)	<b>280</b>	303	(8)	<b>302</b>	226	34
Average production (Boepd)	<b>1,149</b>	1,490	(23)	<b>1,250</b>	1,369	(9)
Average oil price (\$/bbl)	<b>42.41</b>	54.35	(22)	<b>36.02</b>	50.37	(28)
Average natural gas price (\$/mcf)	<b>1.59</b>	2.38	(33)	<b>1.79</b>	2.65	(32)
Average NGL price (\$/bbl)	<b>15.45</b>	16.72	(8)	<b>13.04</b>	14.75	(12)
Average price (\$/BOE)	<b>30.19</b>	39.35	(23)	<b>25.61</b>	38.15	(33)
Oil revenue (\$000)	<b>2,592</b>	4,519	(43)	<b>4,638</b>	8,119	(43)
Natural gas revenue (\$000)	<b>171</b>	355	(52)	<b>470</b>	729	(36)
NGL revenue (\$000)	<b>394</b>	461	(15)	<b>717</b>	604	19

Oil production for the second quarter 2016 was 672 bopd compared to 914 bopd for the same period in 2015, a decrease of 26%. Oil production for the first six months of 2016 was 708 bopd compared to 890 bopd for the first six months of 2015, a decrease of 20%. The production decreases are due to the fracture stimulation operations of the 2 wells in the second quarter of 2015. Oil revenue decreased by 43% in the second quarter of 2016 and 43% for the first six months of 2016 versus the comparable periods in 2015 due to decreases in oil prices of 22% and 28% for the respective periods combined with the production decreases.

For the second quarter of 2016, average natural gas production was 1,181 mcfpd compared to 1,637 mcfpd in the same quarter in 2015, a decrease of 28%. Average natural gas production for the first six months of 2016 was 1,441 mcfpd compared to 1,518 mcfpd in the same period in 2015, a decrease of 5%. The production decreases are due to the initial production volumes from the fracture stimulation operations of the 2 wells in the second quarter of 2015 and a prior period adjustment which decreased second quarter of 2016 natural gas production. Natural gas revenue decreased by 52% in the second quarter 2016 and 36% for the first six months of 2016 versus the comparable periods in 2015 due to decreases in natural gas prices of 33% and 32% for the respective periods combined with the production decreases.

Natural gas liquids (NGL) production in the second quarter of 2016 decreased to 280 boepd from 303 boepd in 2015, a decrease of 8%. The production decrease is due to the initial production volumes from the fracture stimulation operations of the 2 wells in the second quarter of 2015. NGL production for the first six months of 2016 was 302 boepd compared to 226 boepd in the same period in 2015, an increase of 34%. The production increase is due to a higher percentage of NGLs being extracted from gas production during processing, partially offset by the increase in 2015 production from the 2 wells that were completed in the second quarter of 2015. NGL revenue decreased by 15% in the second quarter 2016 compared to the second quarter of 2015 due to the decrease in production combined with a price decrease of 8%. NGL revenue increased by 19% for the first six months of 2016 due to the increase in production partially offset by the decrease in NGL prices.

Production on a per boe basis was 1,149 boepd in the second quarter of 2016 compared to 1,490 boepd in the second quarter of 2015, a decrease of 23%. For the first six months of 2016, production was 1,250 boepd compared to 1,369 boepd for the first six months of 2015, a decrease of 9%. The decreases are due to the factors discussed above. Gross revenue in the second quarter of 2016 decreased by 41% compared to the second quarter of 2015 due to a 23% decrease in average prices combined with the 23% production decrease. Gross revenue for the first six months of 2016 decreased by 38% compared to the same period of 2015 due to a 33% decrease in average prices combined with the 9% production decrease.

## Royalties, Operating Expenses and Netbacks<sup>(1)</sup>

(\$/BOE)	Three months ended June 30			Six months ended June 30		
	2016	2015	%	2016	2015	%
Average price	<b>30.19</b>	39.35	(23)	<b>25.61</b>	38.15	(33)
Royalties	<b>6.83</b>	9.51	(28)	<b>5.79</b>	8.94	(35)
Operating expenses	<b>5.46</b>	4.96	10	<b>4.94</b>	5.00	(1)
Netbacks <sup>(1)</sup>	<b>17.90</b>	24.88	(28)	<b>14.88</b>	24.21	(39)

(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 the first quarter and first six months of 2016 was due to significant price decreases in oil and natural gas. For the second quarter of 2016, oil was 58% of the production mix compared to 61% in the second quarter of 2015. Oil made up 57% of the production mix in the first six months of 2016 compared to 65% of oil in the production mix for first six months of 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.

Royalties on Tishomingo production averaged approximately 22.6% for 2016 versus 23.4% in 2015 due to different royalty burdens on the leases drilled by the Company.

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 were \$571,000 for the second quarter of 2016 compared to \$672,000 for the same period of 2015. Operating expenses were \$1,123,000 for the first six months of 2016 compared to \$1,244,000 for the same period of 2015. The operating expense decreases reflect the Company’s continued cost cutting efforts.

### Realized and Unrealized Gains and Losses from Risk Management Contracts

The Company has 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 June 30, 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	July 1, 2016 to December 31, 2016	16,700	\$89.90
Oil - WTI	July 1, 2016 to December 31, 2016	64,127	\$60.13
Oil – WTI	January 1, 2017 to June 30, 2017	14,500	\$87.65
Oil - WTI	January 1, 2017 to December 31, 2017	117,951	\$60.13
Oil - WTI	January 1, 2018 to January 31, 2019	8,818	\$60.13

Oil - WTI	January 1, 2018 to December 31, 2018	89,892	\$54.70
Oil - WTI	July 1, 2016 to December 31, 2016	7,020	\$48.40
Oil - WTI	January 1, 2017 to December 31, 2017	11,870	\$48.40
Oil - WTI	January 1, 2017 to December 31, 2017	25,460	\$48.40
Oil - WTI	January 1, 2018 to December 31, 2018	102,010	\$48.40
Oil - WTI	January 1, 2019 to April 30, 2019	30,920	\$48.40
Gas - Henry Hub	July 1, 2016 to December 31, 2016	73,260	\$3.06
Gas - Henry Hub	July 1, 2016 to December 31, 2016	27,990	\$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
Gas - Henry Hub	July 1, 2016 to December 31, 2016	12,225	\$2.93
Gas - Henry Hub	January 1, 2017 to December 31, 2017	26,045	\$2.93
Gas - Henry Hub	January 1, 2018 to December 31, 2018	50,629	\$2.93
Gas - Henry Hub	July 1, 2019 to December 31, 2019	138,883	\$2.93
Gas - Henry Hub	January 1, 2020 to March 31, 2020	31,571	\$2.93

The estimated fair value of \$1.7 million as at June 30, 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<sup>(1)</sup> would be as follows:

#### Netbacks including Commodity Contracts <sup>(1)</sup>

(\$/BOE)	Three months ended June 30			Six months ended June 30		
	2016	2015	%	2016	2015	%
Average price	<b>39.45</b>	44.31	(11)	<b>37.22</b>	44.38	(16)
Royalties	<b>6.83</b>	9.51	(28)	<b>5.79</b>	8.94	(35)
Operating expenses	<b>5.46</b>	4.96	10	<b>4.94</b>	5.00	(1)
Netbacks including commodity contracts <sup>(1)</sup>	<b>27.16</b>	29.84	(9)	<b>26.49</b>	30.44	(13)

(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 second quarter of 2016 were \$1.1 million compared to \$1.5 million for the same period of 2015, a decrease of 29%. G&A for the first six months of 2016 were \$2.5 million compared to \$3.6 million for the same period of 2015, a decrease of 30%. These decreases in G&A compared to 2015 relate primarily to management's efforts to reduce costs throughout the Company. This resulted in reductions in salary and benefit costs, legal, accounting and consulting fees and travel costs.

## **Depletion and Depreciation**

Depletion and depreciation expense for the second quarter of 2016 was \$1,424,000 compared to \$2,179,000 in the same period of 2015. Depletion and depreciation expense for the first six months of 2016 was \$3,095,000 compared to \$3,990,000 in the same period of 2015. The decrease for both periods is due to decreased production. Depletion and depreciation expense on a per barrel basis was \$13.62 for the second quarter of 2016 compared to \$16.07 in the second quarter of 2015. Depletion and depreciation expense on a per barrel basis was \$13.60 for the first six months of 2016 compared to \$16.09 in the first six months of 2015.

## **Stock based compensation**

Stock based compensation increased from \$178,000 for the second quarter of 2015 to \$326,000 in the second quarter of 2016. For the first six months of 2016, stock based compensation increased from \$358,000 in 2015 to \$368,000 in 2016. These increases were due to the timing of stock awards granted to directors and employees.

## **Interest on loans and borrowings**

Interest on loans and borrowings increased from \$417,000 for the second quarter of 2015 to \$499,000 for the second quarter of 2016. For the first six months, interest increased from \$876,000 in 2015 to \$1,026,000 in 2016. The increases are due to the Company's additional borrowings in February 2015 on the credit facility with Morgan Stanley Capital Group Inc.

## **Net income (loss) for the period and cash used in operating activities**

The Company incurred a net loss of \$5,310,000 (\$0.03 per share) for the second quarter of 2016 compared to a net loss of \$3,658,000 (\$0.02 per share) for the same period of 2015. The 2016 net loss compared to the net loss for the same period in 2015 is due to a decrease in net revenue of \$1,601,000, a combined loss in risk management contracts for the second quarter of 2016 of \$3,760,000 versus a combined loss of \$2,411,000 for the second quarter of 2015, an increase in stock based compensation of \$148,000 an increase in interest on long term debt of \$82,000, partially offset by a decrease in depletion and depreciation expense of \$755,000, a decrease in net loss from discontinued operations of \$247,000, a decrease in general and administrative costs of \$441,000 and a decrease in operating expenses of \$101,000.

The Company incurred a net loss of \$6,560,000 (\$0.04 per share) for the first six months of 2016 compared to a net loss of \$4,418,000 (\$0.03 per share) for the same period of 2015. The 2016 net loss compared to the net loss for the same period in 2015 is due to a decrease in net revenue of \$2,728,000, an increase in loss on risk management contracts of \$2,511,000, and an increase in interest on long term debt of \$150,000, partially offset by a decrease in net loss from discontinued operations of \$901,000, a decrease in depletion and depreciation expense of \$895,000, a decrease in general and administrative costs of \$1,078,000, a decrease in foreign exchange loss of \$224,000 and a decrease in operating expenses of \$121,000.

Cash provided by operating activities for the first six months of 2016 was \$3,091,000 compared to \$2,862,000 for the same period in 2015.

## CAPITAL EXPENDITURES

(\$000, except as noted)

	Six months ended June 30	
	2016	2015
Additions to oil and gas properties	\$ 537	\$ 8,397
Additions to exploration and evaluation	-	169
	<u>\$ 537</u>	<u>\$ 8,566</u>

For the first six months of 2016, the Company spent approximately \$0.5 million in the U.S.

## LIQUIDITY AND CAPITAL RESOURCES

	At June 30,	
	2016	2015
Working Capital (US\$)	\$ <u>5,278,000</u>	\$ <u>2,310,000</u>
Loans and Borrowings (US\$)	\$ <u>22,600,000</u>	\$ <u>24,400,000</u>
Shares Outstanding, end of period	162,689,292	162,689,292
Market Price per share, end of period (in Canadian \$)	\$ 0.29	\$ 0.52
Market Value of Shares (in Canadian \$)	\$ <u>47,179,895</u>	\$ <u>84,598,432</u>

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. In April 2016, the Company made a \$1.8 million pay down on the credit facility to reduce the outstanding balance on the credit facility to \$22.6 million. Primary debt covenants of the facility require the US subsidiary to maintain a positive working capital balance, to ensure the ratio of outstanding debt to an adjusted EBITDA amount be no greater than 4 to 1 at any quarter end and to ensure the ratio of adjusted EBITDA to interest expense be no less than 2.5 at any quarter end. At June 30, 2016, the Company was in compliance with all of these covenants. At June 30, 2016 loans and borrowings of \$22.6 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 July 2016, the Company made an additional paydown of \$1.4 million to reduce the outstanding balance to \$21.2 million at July 31, 2016, with \$3.2 million available to borrow on the credit facility.

At June 30, 2016 the Company had net working capital of \$5.3 million versus \$2.3 million at June 30, 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 June 30, 2016:

	Total	2016	2017	2018
Loans and borrowings *	(22,600)	-	-	(22,600)
Trade and other payables	(2,332)	(2,332)	-	-
	<u>(24,932)</u>	<u>(2,332)</u>	<u>0</u>	<u>(22,600)</u>

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

## COMMITMENTS

The Sedano and Urraca concession applications in Spain 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.

BNK Spain has submitted documents to relinquish the Sedano concession and is awaiting a response from the Spanish government.

## QUARTERLY SUMMARY

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

(\$000, except as noted)	2016		2015	
	Q2	Q1	Q4	Q3
<b>Daily Production</b>				
Oil (bpd)	672	744	832	904
Natural gas (mcfpd)	1,181	1,702	1,436	1,799
NGL's (bpd)	280	324	296	350
Average production (boepd)	1,149	1,352	1,367	1,554

(\$000, except as noted)	2015		2014	
	Q2	Q1	Q4	Q3
<b>Daily Production</b>				
Oil (bpd)	914	867	910	673
Natural gas (mcfpd)	1,637	1,397	1,182	1,024
NGL's (bpd)	303	149	173	127
Average production (boepd)	1,490	1,249	1,280	971

(\$000, except as noted)	2016		2015	
	Q2	Q1	Q4	Q3
<b>Average Price</b>				
Oil (\$/bbl)	42.41	30.24	39.36	44.41
Natural gas (\$/mcf)	1.59	1.93	1.89	2.54
NGL (\$/bbl)	15.45	10.96	13.54	12.78
Average price (\$/bbl)	30.19	21.69	28.86	31.65

(\$000, except as noted)	2015		2014	
	Q2	Q1	Q4	Q3
<b>Average Price</b>				
Oil (\$/bbl)	54.35	46.13	72.11	96.60
Natural gas (\$/mcf)	2.38	2.97	3.53	3.72
NGL (\$/bbl)	16.72	10.68	24.55	30.32
Average price (\$/bbl)	39.35	36.62	57.82	74.80

(\$000, except as noted)	2016		2015	
	Q2	Q1	Q4	Q3
<b>Netback<sup>(1)</sup></b>				
Average price (\$/boe)	30.19	21.69	28.86	31.65
Royalties	6.83	4.91	6.57	7.39
Operating expenses	5.46	4.49	5.19	5.02
Netback (\$/boe)	17.90	12.29	17.10	19.24

(\$000, except as noted)	2015		2014	
	Q2	Q1	Q4	Q3
<b>Netback<sup>(1)</sup></b>				
Average price (\$/boe)	39.35	36.62	57.82	74.80
Royalties	9.51	8.24	10.84	14.02
Operating expenses	4.96	5.05	5.38	8.64
Netback (\$/boe)	24.88	23.33	41.60	52.14

(\$000, except as noted)	2016		2015	
	Q2	Q1	Q4	Q3
<b>Net operating income<sup>(2)</sup></b>				
Oil and gas revenue	3,157	2,669	3,834	4,525
Royalties	714	604	826	1,056
Operating expenses	571	552	653	717
	1,872	1,513	2,355	2,752

(\$000, except as noted)	2015		2014	
	Q2	Q1	Q4	Q3
<b>Net operating income<sup>(2)</sup></b>				
Oil and gas revenue	5,335	4,117	6,809	6,682
Royalties	1,290	926	1,277	1,253
Operating expenses	672	568	634	772
	3,373	2,623	4,898	4,657

(\$000, except as noted)	2016		2015	
	Q2	Q1	Q4	Q3
<i>Net earnings (loss)</i>	(5,310)	(1,250)	(6,351)	4,198
<i>Basic and Fully Diluted Earnings (loss) per share</i>	(0.03)	(0.01)	(0.04)	0.03
<i>Funds from operations</i> <sup>(3)</sup>	1,369	1,172	1,352	1,376
<i>Bank debt</i>	22,600	24,400	24,400	24,400
<i>Total assets</i>	142,067	148,533	149,806	158,514

(\$000, except as noted)	2015		2014	
	Q2	Q1	Q4	Q3
<i>Net earnings (loss)</i>	(3,658)	(760)	(57,628)	(299)
<i>Basic and Fully Diluted Earnings (loss) per share</i>	(0.02)	0.00	(0.36)	0.00
<i>Funds from operations</i> <sup>(3)</sup>	1,113	1,017	3,651	1,850
<i>Bank debt</i>	24,400	24,400	15,401	15,420
<i>Total assets</i>	157,456	161,377	163,429	222,285

(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 and Euro 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 August 11, 2016, June 30, 2016 and June 30, 2015 respectively. The Company had 11,150,833, 11,180,833 and 9,817,000 stock options outstanding as of August 11, 2016, June 30, 2016 and June 30, 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](http://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 of 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 ("Mcf"). 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](http://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** <sup>2,3,5</sup>  
Director, Chairman of the Board

**Gregory M. Cameron** <sup>1,3</sup>  
Director

**Victor Redekop** <sup>1,2,4,5</sup>  
Director

**Eric Brown** <sup>1,2,3</sup>  
Director

**General Wesley K. Clark** <sup>4</sup>  
Director

**Leslie O'Connor** <sup>5</sup>  
Director

**Wolf Regener** <sup>4</sup>  
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: BXX

### LEGAL COUNSEL

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

### CONSULTING ENGINEERS

Netherland, Sewell & Associates, Inc.  
Houston, TX, USA

### TRANSFER AGENT AND REGISTRAR

Computershare Trust Company  
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