MANAGEMENT'S DISCUSSION AND ANALYSIS

SEPTEMBER 30, 2015

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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 and nine months ended September 30, 2015, 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 nine months ended September 30, 2015 and the audited consolidated financial statements and MD&A for the year ended December 31, 2014. 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, 2014. The reporting and measurement currency is the United States dollar. Additional information relating to BNK including its Annual Information Form is filed on SEDAR at www.sedar.com and on the Company's website at www.bnkpetroleum.com.

This report is prepared as of November 6, 2015. 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 September 30,		Nine Months ended September 30,	
	2015	**2014**	**2015**	**2014**
Financial (US $000 except as noted)				
Oil and gas revenue	**3,470**	5,428	**10,705**	16,967
Net operating income	**2,753**	4,656	**8,744**	14,975
Net income (loss)	**4,197**	(299)	**(221)**	150
Basic and diluted net income (loss) per share	**0.03**	0.00	**0.00**	0.00
Cash flow from operations	**1,680**	2,889	**4,542**	8,185
Additions to property, plant and equipment	**685**	17,637	**9,081**	30,124
Additions to exploration and evaluation assets	**281**	4,445	**451**	27,622
Operating				
Average production (Boepd)	**1,554**	971	**1,432**	977
Average price ($/BOE)	**31.65**	74.80	**35.75**	78.29
Netbacks ($/BOE)	**19.24**	52.14	**22.37**	56.14

	Sep-15	**Jun-15**	**Mar-15**	**Dec-14**
Balance Sheet				
Cash and cash equivalents	**2,283**	**3,748**	6,757	12,035
Total assets	**158,514**	**157,456**	161,377	163,429
Adjusted working capital	**5,402**	**2,310**	6,827	663
Total non-current liabilities	**25,205**	**25,917**	25,871	1,355

* Adjusted working capital excludes the current portion of long-term debt.

Highlights

In the second quarter 2015, as previously reported, the Company completed fracture stimulation operations on the previously drilled Nickel Hill 36-3H well and the Emery 17-1H well, where 6 stages had already been completed in late 2014. The average production for the third quarter of 2015 was 1,554 BOEPD, an increase of 60% compared to third quarter 2014 production of 971 BOEPD. The average production for the nine months ended September 30, 2015 was 1,432 BOEPD, an increase of 46% compared to the first nine months of 2014 production of 977 BOEPD.

Gross revenues for the third quarter 2015 decreased by 36% compared to the third quarter of 2014. Gross revenues for the nine months ending September 30, 2015 decreased by 37% compared to the same period of 2014. Cash flow from operations was $1.7 million for the third quarter of 2015 compared to $2.9 million in the third quarter of 2014. Cash flow from operations was $4.5 million for the nine months ending September 30, 2015 compared to $8.2 million in the same period of 2014. The decrease in revenues and cash flow from operations was due to the 54% decrease in oil prices in the third quarter of 2015 and 51% in the nine months ending September 30, 2015 compared to the same periods in 2014.

Due to the Company's 2015 global cost cutting efforts, general & administrative expenses decreased by 45% for the third quarter of 2015 and 34% for the first nine months of 2015 and operating expenses on a per barrel basis decreased by 42% for the third quarter of 2015 and 33% for the first nine months of 2015 compared to the comparable periods in 2014.

Netbacks decreased from $52.14 in the third quarter 2014 to $19.24 in the third quarter of 2015, a decrease of 63%. Netbacks decreased from $56.14 in the first nine months of 2014 to $22.37 for the same period of 2015, a decrease of 60%. The decreases were due to the average price per BOE decreases of 58% for the third quarter and 54% for nine months compared to the comparable prior year periods.

Net income for the third quarter 2015 was $4.2 million compared to net loss of $0.3 million in the third quarter of 2014. Net loss for the first nine months of 2015 was $0.2 million compared to net income of $0.2 million for the same period in 2014.

In February 2015, the Company's US subsidiary received an additional $8.5 million from its $100 million credit facility with Morgan Stanley Capital Group Inc ("Morgan Stanley"). The total amount borrowed on this credit facility, which is intended for the development of the Tishomingo field in Oklahoma, is now $24.4 million.

OPERATIONS UPDATE

Tishomingo Field, Ardmore Basin, Oklahoma

Production during the third quarter increased due to the fracture stimulation operations on the previously drilled Nickel Hill 36-3H well and the Emery 17-1H well which was completed in the second quarter of 2015. The average production for the third quarter of 2015 was 1,554 BOEPD, an increase of 60% compared to third quarter 2014 production of 971 BOEPD. The average production for the nine months ending September 30, 2015 was 1,432 BOEPD, an increase of 46% compared to the first nine months of 2014 production of 977 BOEPD.

Poland

Poland – Saponis Investments Sp. z o.o.

The Company holds a 100% interest in Saponis, which represents a net acreage holding of approximately 227,032 acres in the Slupsk concession, which expires in June 2018. The Company has received partial approval of an extension modification to drill the first well for this concession by December 2016 instead of during 2015 as was originally scheduled. Full approval of the concession modification is expected prior to year-end although a positive decision cannot be guaranteed. As previously announced, the Company is continuing the process of searching for potential joint venture partners for this concession.

During the third quarter of 2015, the Company completed the physical abandonment and reclamation of the Lebork S-1 well and final reclamation approval is expected during the first quarter of 2016.

Poland – Indiana Investments Sp. z o.o.

During the third quarter of 2015, the Company completed the physical abandonment and reclamation of the Gapowo B1-A well for the expired Bytow concession and final reclamation approval is expected during the first quarter of 2016.

Spain

The Company submitted Environmental Impact Assessments (EIAs) at the end of 2014 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. As per Spanish regulations, these EIAs were published for open public consultation. During the third quarter of 2015, the Company submitted formal responses to the questions and comments generated during the public consultation process. The Spanish administration has received all required documents and has commenced the technical review of these EIA applications. The Company is continuing its campaign to communicate with regulators, politicians, citizens and other stakeholders in Spain about the shale gas exploration and development process, the benefits to all stakeholders, and the safeguards employed to ensure health, environmental and safety compliance.

BNK Spain is also waiting for the assignment of the Rojas concession in Spain, which is adjacent to the Urraca and Sedano concessions. The Rojas concession has not been awarded and there is no assurance that the BNK Spain application will be successful.

Other Projects

In addition, BNK has made other concession applications in other basins in Europe, and is currently awaiting their potential grants.

DISCUSSION OF OPERATING RESULTS

Production and Revenue

	Three months ended September 30			Nine months ended September 30		
	2015	2014	%	**2015**	2014	%
Average oil production (Bopd)	**904**	673	34	**895**	682	31
Average natural gas production (mcf/d)	**1,799**	1024	76	**1,613**	906	78
Average NGL production (Boepd)	**350**	127	176	**268**	144	86
Average production (Boepd)	**1,554**	971	60	**1,432**	977	47
Average oil price ($/bbl)	**44.41**	96.60	(54)	**48.35**	98.65	(51)
Average natural gas price ($/mcf)	**2.54**	3.72	(32)	**2.61**	4.44	(41)
Average NGL price ($/bbl)	**12.78**	30.32	(58)	**13.88**	36.10	(62)
Average price ($/BOE)	**31.65**	74.80	(58)	**35.75**	78.29	(54)
Oil revenue ($000)	**3,693**	5,978	(38)	**11,812**	18,363	(36)
Natural gas revenue ($000)	**420**	350	20	**1,149**	1,098	5
NGL revenue ($000)	**412**	354	16	**1,016**	1,421	(29)

Oil production for the third quarter 2015 was 904 bopd compared to 673 bopd for the same period in 2014, an increase of 34%. Oil production for the first nine months of 2015 was 895 bopd compared to 682 bopd for the first nine months of 2014, an increase of 31%. The production increases were due to the Caney wells that were drilled and completed in 2015. Oil revenue decreased by 38% in the third quarter 2015 and 36% for the first nine months of 2015 versus the comparable periods in 2014 due to decreases in oil prices of 54% and 51% for the respective periods, which was partially offset by the production increases.

For the third quarter 2015, average natural gas production was 1,799 mcfpd compared to 1,024 mcfpd in the same quarter in 2014, an increase of 76%. Average natural gas production for the first nine months of 2015 was 1,613 mcfpd compared to 906 mcfpd in the same period in 2014, an increase of 78%. The production increases were due to the Caney wells that were drilled and completed in 2015. Natural gas prices decreased 32% in the third quarter and 41% in the first nine months of 2015, compared to the corresponding prior year periods.

Natural Gas Liquids (NGL) production in the third quarter of 2015 increased to 350 boepd from 127 boepd in 2014, an increase of 176%. NGL production for the first nine months of 2015 was 268 boepd compared to 144 boepd in the same period in 2014, an increase of 86%. The production increases were due to the Caney wells that were drilled and completed in 2015. NGL revenue increased by 16% in the third quarter 2015 compared to the third quarter of 2014 due to the increase in production, which was partially offset by a price decrease of 58%. NGL revenue decreased by 29% for the first nine months of 2015 due to a price decrease of 62%, which was partially offset by the increase in production.

Production on a per boe basis was 1,554 boepd in the third quarter of 2015 compared to 971 boepd in the third quarter of 2014, an increase of 60%. For the first nine months of 2015, production was 1,432 boepd compared to 977 boepd for the first nine months of 2014, an increase of 47%. The increases are due to the factors discussed above. Gross revenue in the third quarter of 2015 decreased by 32% compared to the third quarter of 2014 due to a 58% decrease in average prices, partially offset by the production increase. Gross revenue for the first nine months of 2015 decreased by 33% compared to the same period of 2014 due to a 54% decrease in average prices, partially offset by the production increase.

Royalties, Operating Expenses and Netbacks

	Three months ended September 30			Nine months ended September 30		
($/BOE)	**2015**	2014	%	**2015**	2014	%
Average price	**31.65**	74.80	(58)	**35.75**	78.29	(54)
Royalties	**7.39**	14.02	(47)	**8.37**	14.68	(43)
Operating expenses	**5.02**	8.64	(42)	**5.01**	7.47	(33)
Netback	**19.24**	52.14	(63)	**22.37**	56.14	(60)

The average price decrease for 2015 was due to significant price decreases in all commodities, specifically oil. Oil made up 63% of the production mix in the first nine months of 2015 compared to 70% of oil in the production mix for first nine months of 2014. For the third quarter of 2015, oil was 58% of the production mix compared to 69% in the third quarter of 2014. 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 the Company was allocated higher NGL yields in the third quarter of 2015 than in previous quarters.

Royalties on Tishomingo production averaged approximately 23.4% for 2015 versus 18.75% in 2014 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 $717,000 for the third quarter 2015 compared to $772,000 for the same period of 2014. Operating expenses were $1,961,000 for the first nine months of 2015 compared to $1,992,000 for the same period of 2014. Operating expenses in the first nine months of 2015 include non-recurring costs of over $30,000 related to repairs and maintenance from the heavy flooding in Oklahoma during the second quarter of 2015.

Operating expenses averaged $5.02 per boe during the third quarter of 2015 compared to $8.64 per boe in 2014 and $5.01 for the first nine months of 2015 compared to $7.47 for the same period of 2014. The per barrel operating expense decreases of 42% in the third quarter of 2015 and 33% for the nine months of 2015 compared to the comparable prior year periods reflect the Company’s cost cutting efforts in 2015.

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 September 30, 2015 the following financial commodity contracts were outstanding and recorded at estimated fair value:

Commodity	Period	Total Volume Hedged (BBLS/MMBTU)	Price ($/BBL or $/MMBTU)
Oil – WTI	October 1, 2015 to December 31, 2015	10,800	$96.25
Oil – WTI	January 1, 2016 to December 31, 2016	35,600	$89.90
Oil – WTI	January 1, 2017 to June 30, 2017	14,500	$87.65
Oil - WTI	October 1, 2015 to December 31, 2015	45,158	$60.13
Oil - WTI	January 1, 2016 to December 31, 2016	139,851	$60.13
Oil - WTI	January 1, 2017 to June 30, 2017	117,952	$60.13
Oil - WTI	January 1, 2018 to January 31, 2018	8,818	$60.13
Gas - Henry Hub	October 1, 2015 to December 31, 2015	50,621	$3.06
Gas - Henry Hub	January 1, 2016 to December 31, 2016	158,981	$3.06
Gas - Henry Hub	January 1, 2017 to June 30, 2017	119,993	$3.06
Gas - Henry Hub	January 1, 2018 to January 31, 2018	7,983	$3.06

The estimated fair value of $5.7 million as at September 30, 2015 of the financial oil contracts has been determined based on the prospective amounts that the Company would receive or pay to terminate the contracts.

In October 2015, subsequent to the end of the third quarter, the Company entered into additional financial commodity contracts which are summarized in the table below.

Commodity	Period	Total Volume Hedged (BBLS/MMBTU)	Price ($/BBL or $/MMBTU)
Oil – WTI	January 1, 2018 to December 31, 2018	89,892	$54.70
Gas - Henry Hub	December 1, 2015 to December 31, 2015	7,546	$2.20
Gas - Henry Hub	January 1, 2016 to December 31, 2016	67,176	$2.475
Gas - Henry Hub	January 1, 2017 to December 31, 2017	46,824	$2.80
Gas - Henry Hub	January 1, 2018 to January 31, 2018	116,772	$2.90

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

Netbacks including Commodity Contracts

	Three months ended September 30			Nine months ended September 30		
($/BOE)	**2015**	2014	%	**2015**	2014	%
Average price	**40.91**	76.25	(46)	**43.09**	78.78	(45)
Royalties	**7.39**	14.02	(47)	**8.37**	14.68	(43)
Operating expenses	**5.02**	8.64	(42)	**5.01**	7.47	(33)
	28.50	53.59	(47)	**29.71**	56.63	(48)

General and Administrative Expenses

General and administrative expenses (G&A) for the third quarter were $1.7 million compared to $3.0 million for the same period of 2014, a decrease of 43%. G&A for the first nine months of 2015 were $6.0 million compared to $9.0 million for the same period of 2014, a decrease of 33%. These decreases in G&A compared to 2014 relate primarily to management's efforts to reduce costs throughout the Company. This resulted in reductions in employee salary and benefit costs, director fees, legal and professional fees and travel costs.

Depletion and Depreciation

Depletion and depreciation expense for the third quarter of 2015 was $2,303,000 compared to $1,884,000 in the same period of 2014. Depletion and depreciation expense for the first nine months of 2015 was $6,335,000 compared to $5,578,000 in the same period of 2014. The increase for both periods is due to a higher depletion base and increased production. Depletion and depreciation expense on a per barrel basis was $16.08 for the third quarter of 2015 compared to $21.08 in the third quarter of 2014.

Stock based compensation

Stock based compensation decreased from $439,000 for the third quarter of 2014 to $138,000 in the third quarter of 2015. For the first nine months of 2015, stock based compensation decreased from $1,130,000 in 2014 to $496,000 in 2015. These decreases were due to stock option grants awarded to employees in 2014 combined with a higher stock price in 2014 compared to 2015.

Interest on loans and borrowings

Interest on loans and borrowings increased from $107,000 for the third quarter 2014 to $499,000 for the third quarter 2015. For the first nine months, interest increased from $110,000 in 2014 to $1,448,000 in 2015. This increase is due to the Company's $24.4 million of borrowings on its credit facility with Morgan Stanley.

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

The Company had net income of $4,197,000 ($0.03 per share) for the third quarter of 2015 compared to a net loss of $299,000 ($0.00 per share) for the same period of 2014. The 2015 net income compared to the loss for the same period in 2014 is due to a gain in risk management contracts for the third quarter of 2015 of $5,610,000 versus a gain of $1,113,000 for the third quarter of 2014, a decrease in general and administrative costs of $1,375,000, an increase in other income of $564,000, restructuring expenses of $438,000 in 2014 versus no costs in 2015, a decrease in stock based compensation of $301,000, and a loss from equity investment in 2014 of

$166,000 versus no loss in 2015, partially offset by a decrease in net revenue of $1,958,000, an increase in depletion of $419,000, and an increase in interest on long term debt of $392,000.

The Company incurred a net loss of $221,000 ($0.00 per share) for the first nine months of 2015 compared to net income of $150,000 ($0.00 per share) for the same period of 2014. The 2015 net loss compared to the net income for the same period in 2014 is due to a decrease in net revenue of $6,262,000, an increase in interest on long term debt of $1,338,000, an increase in depletion of $757,000 a foreign exchange loss of $315,000 in 2015 compared to a foreign exchange gain of $124,000 in 2014, and a decrease in management fees of $236,000, partially offset by an increase in gain on risk management contracts of $4,270,000, decrease in general and administrative costs of $3,001,000, a decrease in stock based compensation of $634,000, an increase in other income of $542,000, and a decrease in restructuring expenses of $198,000.

Cash provided by operating activities for the first nine months of 2015 was $4,542,000 compared to cash provided by operating activities of $8,185,000 for the same period in 2014.

CAPITAL EXPENDITURES

($000, except as noted)

	Nine months ended September 30	
	2015	2014
Additions to oil and gas properties	**$ 9,081**	$ 30,124
Additions to exploration and evaluation	**451**	27,622
	$ 9,532	$ 57,746

For the first nine months of 2015, the Company spent approximately $9.1 million in the U.S. all of which was incurred on drilling and completion costs. In addition, the Company spent $0.5 million on exploration and evaluation costs mainly in Spain.

LIQUIDITY AND CAPITAL RESOURCES

	At September 30,	
	2015	**2014**
Adjusted Working Capital (US$)	**$ 5,402,000**	$ **13,972,000**
Loans and Borrowings (US$)	**$ 24,400,000**	$ **15,900,000**
Shares Outstanding, end of period	**162,689,292**	**162,682,624**
Market Price per share, end of period (in Canadian $)	**$ 0.38**	**$ 0.93**
Market Value of Shares (in Canadian $)	**$ 61,821,931**	**$ 151,294,840**

At September 30, 2015 the Company had net adjusted working capital of $5.4 million versus net adjusted working capital of $14.0 million at September 30, 2014. 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 continues to pursue farm-out arrangements for certain of its European concessions. 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 2015. Other potential sources of cash flow include proceeds from individual concession sales or farm-out arrangements in Europe and additional debt or equity offerings.

CONTRACTUAL OBLIGATIONS

The following are the contractual maturities of financial liabilities, excluding estimated interest payments at December, 31, 2015:

	Total	2015	2016	2017	2018
Loans and borrowings *	(24,400)	-	-	-	(24,400)
Trade and other payables	(4,756)	(4,756)	-	-	-
	(29.156)	(4,756)	0	0	(24,400)

* See "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 June 2014, Saponis received approval for a concession modification that extends the Slupsk concession by four years to June 2018. The terms of this extension stipulate that three wells and 70 km of 2D seismic should be acquired prior to the end of the concession. This extension also provides Saponis with the flexibility to drill optional wells and acquire optional 2D and 3D seismic.

The Company has applied for a concession modification requesting that the date of completing operations for the next well and new seismic acquisition (70 km of 2D) be extended to December 2016. The remaining two wells should be drilled prior to the end of the concession, unless the concession is relinquished prior to this date. During the third quarter, the Company received approval of the first part of the Concession Modification procedure (the revised Geological Work Plan). Full approval of the concession modification is expected prior to year-end although a positive decision cannot be guaranteed.

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 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 Company is continuing to progress the current year work program for each of the Sedano and Urraca concessions. These 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 prior to 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.

QUARTERLY SUMMARY

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

	2015			2014
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**
Daily Production				
Oil (bpd)	904	914	867	910
Natural gas (mcfpd)	1,799	1,637	1,397	1,182
NGL's (bpd)	350	303	149	173
Average production (boepd)	1,554	1,490	1,249	1,280

	2014			2013
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**
Daily Production				
Oil (bpd)	673	722	651	533
Natural gas (mcfpd)	1,024	822	870	879
NGL's (bpd)	127	140	166	197
Average production (boepd)	971	999	962	877

	2015			2014
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**
Average Price				
Oil ($/bbl)	44.41	54.35	46.13	72.11
Natural gas ($/mcf)	2.54	2.38	2.97	3.53
NGL ($/bbl)	12.78	16.72	10.68	24.55
Average price ($/bbl)	31.65	39.35	36.62	57.82

($000, except as noted)	2014 Q3	2014 Q2	2014 Q1	2013 Q4
Average Price				
Oil ($/bbl)	96.60	101.93	97.15	96.13
Natural gas ($/mcf)	3.72	4.48	5.27	3.38
NGL ($/bbl)	30.32	31.28	44.73	38.03
Average price ($/bbl)	74.80	81.74	78.18	70.39

($000, except as noted)	2015 Q3	2015 Q2	2015 Q1	2014 Q4
Netback				
Average price ($/boe)	31.65	39.35	36.62	57.82
Royalties	7.39	9.51	8.24	10.84
Operating expenses	5.02	4.96	5.05	5.38
Netback ($/boe)	19.24	24.88	23.33	41.60

($000, except as noted)	2014 Q3	2014 Q2	2014 Q1	2013 Q4
Netback				
Average price ($/boe)	74.80	81.74	78.18	70.39
Royalties	14.02	15.33	14.66	13.20
Operating expenses	8.64	7.56	6.16	6.54
Netback ($/boe)	52.14	58.85	57.36	50.65

($000, except as noted)	2015 Q3	2015 Q2	2015 Q1	2014 Q4
Net operating income				
Oil and gas revenue	4,525	5,335	4,117	6,809
Royalties	1,056	1,290	926	1,277
Operating expenses	717	672	572	634
	2,752	3,373	2,619	4,898

	2014			2013
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**
Net operating income				
Oil and gas revenue	6,682	7,432	6,770	5,679
Royalties	1,253	1,394	1,269	1,065
Operating expenses	772	687	533	528
	4,657	5,351	4,968	4,086

	2015			2014
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**
Net earnings (loss)	4,197	(3,658)	(760)	(57,628)
Basic and Fully Diluted Earnings (loss) per share	0.03	(0.02)	0.00	(0.36)
Funds from operations	1,693	1,779	383	3,651
Bank debt	24,400	24,400	24,400	15,401
Total assets	158,514	157,456	161,377	163,429

	2014			2013
($000, except as noted)	**Q3**	**Q2**	**Q1**	**Q4**
Net earnings (loss)	(299)	199	250	(11,016)
Basic and Fully Diluted Earnings (loss) per share	0.00	0.00	0.00	(0.08)
Funds from operations	1,850	2,808	2,302	1,027
Bank debt	15,420	100	100	100
Total assets	222,285	207,415	201,041	184,803

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.
- 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:

<u>Oil and gas assets</u>

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.

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

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

Asset retirement obligations

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

Derivative instruments

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

Compensation costs

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

Income taxes

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

OUTSTANDING SHARE DATA

There were 162,689,292, 162,689,292 and 162,682,624 common shares outstanding as at November 6, 2015, September 30, 2015 and September 30, 2014 respectively. The Company had 8,970,333, 9,208,667 and 10,967,699 stock options outstanding as of November 6, 2015, September 30, 2015 and September 30, 2014, 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:

- diversifying its exploration concession agreements over multiple foreign locations
- 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.

Internationally, the Company expects to continue its efforts to obtain the necessary permits to drill exploration wells on other concessions in Europe in which it has an interest. Industry partnerships may be created for some of these projects, where BNK would not have to pay for 100% of the exploration phase of a project(s). The Company continues to work on identifying additional basins that it believes are prospective for shale oil and gas as well. At present, there are a number of pending applications that the Company may be granted.

NON-GAAP MEASURES

Netback per barrel, net operating income, funds from operations and adjusted working capital (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.

Adjusted working capital is current assets minus current liabilities excluding the current portion of long term debt. The Company believes that this measure provides a more complete understanding of its operating working capital and the funds available to meet its current liquidity requirements.

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 has been issued but does not have a fixed implementation date. The Company has not yet begun the process of assessing the impact that the new standard will have on its consolidated financial statements.

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.

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 and their anticipated timing, future well stimulations, the anticipated timing of well-site construction, 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 and marketable securities 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, 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), 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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Vancouver, BC

AUDITORS
KPMG, LLP
Calgary, AB

BANKERS
Amegy Bank National Association
Denver, CO, USA

HSBC Bank Canada
Calgary, AB

Morgan Stanley
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