International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended September 30, 2017 and 2016

SECOND QUARTER FISCAL 2018 SUMMARY

Operational Summary:

- **Credit Facility Update** - On September 25, 2017, the Company extended the term of the existing credit facility by an additional 12 months to December 2019 with the next principal repayment to be made at the end of June 2018 (previously December 2017). The borrowing base has been reduced to US $12.5 million from US $15 million previously.

- **Production Volumes** – Production in the second quarter of fiscal 2018 averaged 383 barrels of oil equivalent per day ("boepd"), a 4% increase from the previous quarter and a 1% decrease from Q2 fiscal 2017, respectively. Four of the five wells from the fiscal 2017 drilling campaign are now connected. In Bengal's opinion, operational delays experienced between completion and tie-in may have been a contributor to longer well clean up timing and may have impacted initial reservoir performance. The Joint Venture will continue to monitor well performance.

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $2.4 million in the second quarter of fiscal 2018, which is 5% higher than the $2.3 million recorded in the first quarter of fiscal 2018 due to higher production volumes. Revenues in Q2 fiscal 2018 were 5% higher than Q2 fiscal 2017 due to higher realized commodity pricing.

- **Derivative contracts in place through December 2018** – From July 2017 through to December 2018, the Company has hedged approximately 135,000 barrels of production at a floor price of US $47 per barrel. During the quarter ended September 30, 2017, realized losses from derivative financial instruments was $0.1 million.

- **Funds Flow from Operations** – Bengal generated funds flow from operations of $0.1 million in the quarter ended September 30, 2017, which is a 90% decrease from the $1.8 million generated in both the preceding quarter and in the second quarter of fiscal 2017. The drop in funds flow from operations is largely due to the rolling off of the previous US $80 per barrel derivative contracts.

- **Net Income (Loss)** – Bengal reported a net loss of $0.5 million for the current quarter compared to net income of $0.5 million in the preceding quarter, and net income of $0.3 million in the second quarter of fiscal 2017. Excluding the impact of unrealized foreign exchange and unrealized hedging gains and losses, the adjusted net loss (1) for the second quarter of fiscal 2018 was $0.4 million compared to adjusted net income of $1.3 million during the preceding quarter and $1.1 million in the second quarter of fiscal 2017.

(1) See non IFRS measurements section on page 6 of this MD&A

Bengal's producing assets are situated in Australia's Cooper Basin, a region featuring large hydrocarbon pools. The Company's core Australian assets: Barrolka, Cuisinier and Tookoonooka are situated within an area of the Cooper Basin. Still in early stages, in terms of appraisal and development, Bengal believes these assets offer attractive upside potential. Australia features a stable political, fiscal and economic environment in which to operate, with a favourable royalty regime for oil and gas production.

OUTLOOK

AUSTRALIA

ATP 752 Barta Block Cuisinier

During the second half of calendar 2017, the Joint Venture continued to evaluate appropriate fracture stimulation candidates. Production testing at newly stimulated wells (Cuisinier 3, 5, 9, 12 and Barta North-1), will assist the Joint Venture in planning for its next drilling and stimulation campaigns. The Cuisinier 23 well has encountered hydrocarbon bearing sands based on logging results, however estimated deliverability is uncertain, therefore future completion and potential stimulation of this well will be evaluated along with production rates from the recently tied-in wells.

Given the current crude pricing environment, the Joint Venture plans to defer the selection of wells for its next drilling program until the results from the recent fracture stimulation program have been fully evaluated and there is sufficient production history on the newly connected wells (Cuisinier 22, Cuisinier 24, Cuisinier 25 and Shefu 1).

The Barta Joint Venture has commenced preliminary discussions on the implementation of a pilot pressure maintenance scheme following receipt of a preliminary Field Development Plan from the operator.

The Joint Venture has completed the acquisition of a 250 km^2 3D seismic program in the Barta West area, immediately west of Cuisinier PL303. Following processing and interpretation of this 3D survey, the JV will high grade prospects to identify the optimal location for an exploration well in 2018.

ATP 934 Barrolka

Bengal has completed reprocessing of 500+ line kilometers of 2D seismic over the permit and interpretation of this data is now complete. Seismic amplitude inversion studies have highlighted the several favorable areas of the permit allowing for additional work that may include the acquisition of 3D seismic or one exploration well in 2018. The Company is encouraged by recent natural gas discoveries surrounding the Barrolka permit, which suggest the presence of a potential basin centered gas play in the region, as well as significant conventional potential for natural gas occurrence in the Permian Toolachee and Patchawarra sandstone reservoirs. Bengal is the operator holding a 71% working interest in this permit and has had preliminary discussions with third parties who may have an interest in farming in on this block.

ATP 732 Tookoonooka Block

The Tookoonooka Permit (ATP 732 – 100% WI effective January 28, 2016) is located in the emerging East Flank oil fairway of the Cooper Basin. Beach Energy Ltd. ("Beach") completed the acquisition of 300 km^2 3D seismic in Tookoonooka in February 2014 and subsequently relinquished its interest in the permit; Bengal was fully carried for the cost of this seismic program. The Company made an application for the required regulatory relinquishment of 1/3 of the block and filed a revised Later Work Program (LWP) application covering the period from March 2017 through March 2019. Among other things, this LWP will allow Bengal to study the Permian gas potential along the northern flank of the permit as well as the largely unexplored oil potential in the southern part of the permit closer to the producing Jackson/Jackson South Field which has produced greater than 49.4 million barrels of oil to date. Regulatory approval of the LWP application was received on May 30, 2017. As a result of the extensive amount of exploration work done during the first term of ATP 732 the LWP for the second term has been approved at a modest cost and includes Geological and Geophysical studies through to March 31, 2019.

ATP 752 Wompi

The Nubba-1 well encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas. Pressure testing, as well as logging, suggests that this Toolachee gas well could be part of a gas column that may be up to 70 metres in height. This implies that the prospective gas pay extends down dip of the Nubba well where seismic indicates the Toolachee section thickens. A Potential Commercial Area (the Yilgarn PCA), which will allow for commercialization, was granted on March 31, 2017. The produced natural gas would likely be pipeline connected to the nearest gas transmission line in the area, which is approximately 5 kilometres from the Nubba-1 well. Wompi (38% Bengal interest) offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential and the Joint Venture is currently evaluating the appropriate timing to continue the development of this discovery, which is not expected to occur during calendar 2017. The Yilgarn PCA was granted for an additional period of 15 years from March 31, 2017 and the associated work program is divided into three five year terms. Work anticipated during these terms includes further Geological, Geophysical and Engineering studies as well as extended production testing of the Nubba well and determination of commercial viability of the Nubba gas accumulation.

AC/RL 10 (formerly AC/P 24), Ashmore Cartier Area, Timor Sea, Offshore Australia

Bengal holds a 10% working interest in the offshore Ashmore Cartier Retention License 10 ("**AC/RL 10**") located in the Ashmore Cartier area west of Australia comprised of approximately 168 square kilometers (41,514 acres). Bengal is partnered with PTTEP Australia Timor Sea Pty Ltd. (90% working interest and operator).

This permit was granted as a five-year Petroleum Retention Lease, AC/RL 10 on March 22, 2013 expiring March 21, 2018. Subject to fulfilling acceptable later work programs, AC/RL10 may be continued for two further five year terms. The operator continues to reprocess existing 3D seismic data and evaluate commercialization options.

Business Development

The Company continues to examine potential transactions targeting complementary asset bases to increase reserves, production and cash flows per share. The area of focus remains to be Australia’s Cooper Basin. however it has been expanded to other areas around the globe..

OPERATING SUMMARY

$000s except per share, volumes and netback amounts	Three Months Ended September 30			Six Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Oil sales revenue	**$2,410**	$2,301	5	**$4,716**	$4,790	(2)
Realized (loss) gain on financial instruments	**$(69)**	$1,316	(105)	**$1,054**	$2,592	(59)
Royalties	**$144**	$34	324	**$283**	$181	56
% of revenue	**6**	1	500	**6**	4	50
Operating & transportation	**$1,238**	$1,190	4	**$1,908**	$2,607	(27)
Operating netback(1)	**$959**	$2,393	(60)	**$3,579**	$4,594	(22)
Cash from operations	**$648**	$1,982	(67)	**$2,338**	$2,938	(20)
Funds from operations:	**$110**	$1,797	(94)	**$1,944**	$3,145	(38)
Per share ($) (basic & diluted)(2)	**0.00**	0.03	(100)	**0.02**	0.05	(60)
Net income (loss)	**$(500)**	$325	(254)	**$49**	$(2,411)	(102)
Per share ($) (basic & diluted)	**0.00**	0.00	-	**0.00**	(0.04)	(100)
Adjusted net income (loss)(3)	**$(364)**	$1,086	(134)	**$904**	$1,651	(45)
Per share ($) (basic & diluted)	**0.00**	0.02	(100)	**0.01**	0.02	(50)
Capital expenditures	**$1,527**	$3,320	(54)	**$2,230**	$3,703	(40)
Oil Volumes (bopd)	**383**	386	(1)	**376**	409	(8)
Netback(1) ($/boe)						
Revenue	**$68.40**	$ 64.72	6	**$68.54**	$64.05	7
Realized gain on financial instruments	**(1.96)**	37.01	(105)	**15.32**	34.66	(56)
Royalties	**4.09**	0.96	326	**4.11**	2.42	70
Operating & transportation	**35.14**	33.47	5	**27.74**	34.86	(20)
Netback/boe	**$27.21**	$ 67.30	(60)	**$52.01**	$61.43	(15)

(1) Operating netback is a non-IFRS measure and includes realized gain on financial instruments. Netback per boe is calculated by dividing revenue (including realized gain on financial instruments) less royalties, operating and transportation costs by the total production of the Company measured in boe.

(2) Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed.

(3) Adjusted net income (loss) and adjusted net income per share are non-IFRS measures. The comparable IFRS measure is net income (loss). A reconciliation of the two measures can be found in the table on page 6.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the three and six months ended September 30, 2017 and 2016. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from July 1, 2017 through September 30, 2017. The terms "prior year's quarter" and "2017 quarter" are used throughout the MD&A for comparative purposes and refer to the period from July 1, 2016 through September 30, 2016. The terms "prior quarter", "preceding quarter" and "previous quarter" refer to the three months ended June 30, 2017.

The fiscal year for the Company is the twelve-month period ending March 31, 2018. The terms "fiscal 2018," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2017 through March 31, 2018. The terms "previous year," "prior year" and "fiscal 2017" are used in the MD&A for comparative purposes and refer to the period from April 1, 2016 through March 31, 2017. The term YTD means year-to-date.

The following abbreviations are used in this MD&A: boepd means barrels of oil equivalent per day; bpd means barrels per day; mcfpd means thousand cubic feet of natural gas per day; $/boe means Canadian dollars per boe; and NGL means natural gas liquids.

Non-IFRS Measurements

Within the MD&A, references are made to terms commonly used in the oil and gas industry. Netbacks, funds from operations per share, adjusted net earnings and adjusted net earnings per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Netbacks equal total revenue (including realized gain on financial instruments) less royalties and operating and transportation expenses calculated on a boe basis. Management utilizes these measures to operational performance. Funds from operations per share is a non IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed. Adjusted net earnings is a non-IFRS measure, which should not be considered an alternative to “Net income (loss)” as presented in the consolidated statement of income (loss) and comprehensive income (loss), and is presented in the Company’s financial reports to assist management and investors in analyzing financial performance net of gains and losses outside of management’s immediate control. Adjusted net earnings equal net income (loss) less unrealized losses/gains on foreign exchange and unrealized losses/gains on financial instruments. Adjusted net earnings per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

The following table reconciles net income (loss) to adjusted net earnings (loss), which is used in the MD&A:

	Three Months Ended September 30			**Six Months Ended September 30**		
($000s)	**2017**	2016	% Change	**2017**	**2016**	% Change
Net income (loss)	**(500)**	325	(254)	**49**	**(2,411)**	(102)
Unrealized loss on financial Instruments	**444**	1,205	(63)	**1,256**	**3,977**	(68)
Unrealized foreign exchange (gain) loss	**(308)**	(444)	(31)	**(401)**	**85**	(572)
Adjusted net earnings (loss)	**(364)**	1,086	(134)	**904**	**1,651**	(45)

RESULTS OF OPERATONS - AUSTRALIA

Netbacks

Production	**Three Months Ended September 30**			**Six Months Ended September 30**		
	2017	2016	% Change	**2017**	2016	% Change
Oil Production (bpd)	**383**	386	(1)	**376**	409	(8)
($000s)						
Oil sales	**2,410**	2,301	5	**4,716**	4,790	(2)
Realized gain (loss) on financial instruments	**(69)**	1,316	(105)	**1,054**	2,592	(59)
Royalties	**144**	34	324	**283**	181	56
Operating and transportation expenses	**1,232**	1,190	4	**1,902**	2,607	(27)
Netback ($000s)	**965**	2,393	(60)	**3,585**	4,594	(22)
Oil sales ($/bbl)	**68.40**	64.72	6	**68.54**	64.05	7
Realized gain (loss) on financial instruments ($/bbl)	**(1.98)**	37.01	(105)	**15.32**	34.66	(56)
Royalties ($/bbl)	**4.09**	0.96	326	**4.11**	2.42	70
Operating and transportation expenses ($/bbl)	**34.97**	33.47	4	**27.64**	34.86	(21)
Netback ($/bbl)	**27.38**	67.30	(59)	**52.11**	61.43	(15)

Production, Commodity Pricing and Sales

Production

Crude oil production increased 4% and decreased 1% compared to the prior quarter and Q2 fiscal 2017, respectively. The increase from Q1 2018 is due to a full quarter of production from the fiscal 2017 wells that were tied in during May 2017. Volume decreased from Q2 fiscal 2017 as the additional volumes from the fiscal 2017 wells were offset partially by natural declines.

Pricing

The price received for Bengal's Australian oil sales is benchmarked on Dated Brent quotes as published by Platts Crude Oil Marketwire for the month in which the Bill of Lading occurs, plus a realized premium. This premium is from marketing contracts negotiated on behalf of the Joint Venture by the current operator that took effect on July 1, 2017. Previously the premium received was based on the Platts Tapis premium.

Realized crude oil prices decreased 1% and increased 6% compared to the prior quarter and Q2 fiscal 2017 respectively. The slight decrease from the prior quarter was due to a strengthening of the Canadian dollar relative to the U.S. dollar offset by increased benchmark pricing.

The following table outlines average benchmark prices compared to Bengal's realized prices:

Prices and Marketing	**Three Months Ended September 30**			**Six Months Ended September 30**		
Average Benchmark Price	**2017**	2016	% Change	**2017**	2016	% Change
Bengal realized crude oil price before realized gain (loss) on financial instruments($CAD/bbl)	**$ 68.40**	$ 64.72	6	**$ 68.54**	$ 64.05	7
Realized gain (loss) on financial Instruments ($CAD/bbl)	**(1.96)**	37.01	(105)	**15.32**	34.66	(56)
Dated Brent oil ($CAD/bbl)	**65.14**	58.74	11	**66.21**	59.26	12
Dated Brent oil ($US/bbl)	**52.11**	45.57	14	**50.97**	45.71	12
Number of CAD$ for 1 AUS$	**0.99**	0.99	-	**1.00**	0.97	3
Number of CAD$ for 1 US$	**1.25**	1.30	(4)	**1.30**	1.30	-

Risk Management Activities

Bengal has entered into financial commodity contracts as part of its risk management program to manage commodity price fluctuations related to its primary producing assets being the Cuisinier field in Australia's Cooper Basin.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its crude oil financial contracts on the statement of financial position at each reporting period with the change in fair value being classified as unrealized gains and losses in the consolidated statement of income (loss).

The Company has the following derivative contracts:

Time Period	**Type of Contract**	**Quantity Contracted (bbls)**	**Price Floor (US$/bbl)**	**Price Ceiling (US$/bbl)**
Oct. 1, 2017 – December 31, 2018	Oil - Swap	56,609	47.00	47.00
Oct. 1, 2017 – December 31, 2018	Oil – Put option	56,609	47.00	-

The fair value of the financial contracts outstanding as at September 30, 2017 is an estimated liability of $0.5 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the three months ended September 30, 2017, the derivative commodity contracts resulted in a realized loss of $0.1 million (Q2 fiscal 2017 - $1.3 million gain) and an unrealized loss of $0.4 million (Q2 fiscal 2017 - $1.2 million loss). The realized and unrealized losses incurred in the current quarter and in Q2 fiscal 2017 were as a result of the below market hedges currently in place and the increase in Brent forward strip pricing. The realized gain in Q2 fiscal 2017 was the result of the US$80 per barrel oil swaps that have now since expired.

Royalties

Royalties ($000s)	**Three Months Ended September 30**			**Six Months Ended September 30**		
	2017	2016	% Change	**2017**	2016	% Change
Royalty Expense	**144**	34	324	**283**	181	56
$/bbl	**4.09**	0.96	326	**4.11**	2.42	70
% of revenue	**6**	1	500	**6**	4	50

In Australia, oil royalties are based on a government-established rate of 10% plus a Native Title royalty which is typically 1%. The royalty rate is applied to gross revenues after deducting an allowance for allowable capital, transportation and operating costs, resulting in an effective rate of less than 10%.

Royalties per barrel have increased 326% compared to Q2 fiscal 2017 and are unchanged compared to the previous quarter. Royalties as a percentage of revenues have significantly increased compared to Q2 fiscal 2017 due to the reduction of allowable capital deductions, due to lower recent drilling activity, against gross royalties. No change to the previous quarter is expected as activity levels have been consistent quarter over quarter.

Operating & Transportation Expenses

Operating & trans. expenses ($000s)	**Three Months Ended September 30**			**Six Months Ended September 30**		
	2017	2016	% Change	**2017**	2016	% Change
Operating	**187**	106	76	**(116)**	293	(140)
Transportation	**1,045**	1,084	(4)	**2,018**	2,314	(13)
	1,232	1,190	4	**1,902**	2,607	(27)
Operating - $/boe	**5.31**	2.98	78	**(1.69)**	3.92	(143)
Transp. - $/boe	**29.66**	30.49	(3)	**29.33**	30.94	(5)
	34.97	33.47	4	**27.64**	34.86	(21)

Operating costs per barrel increased by 78% compared to Q2 fiscal 2017 as the operator allocated less overhead costs to the Joint Venture in the previous period. Costs have returned to normal levels in the current quarter. Operating costs have increased from the prior quarter due to a $0.5 million credit associated with proceeds from a Joint Venture audit realized in Q1 fiscal 2018.

Transportation costs on a boe basis have decreased 3% compared to Q2 fiscal 2017 as the company is realizing some cost reductions in transportation tariffs due to the company negotiating previously disclosed new transportation tariff reductions that are now taking effect. Transportation costs include processing and handling fees which have increased 2% compared with Q1 due to higher water production at the Cuisinier field during Q2.

General and Administrative (G&A) Expenses and Share-based Compensation ("SBC")

G&A Expenses and SBC ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Net G&A	**611**	650	(6)	**1,159**	1,369	(15)
Capitalized G&A	**73**	83	(12)	**156**	172	(9)
Total G&A	**684**	733	(7)	**1,315**	1,541	(15)
Expensed share-based compensation	**32**	14	129	**39**	25	56
Capitalized share-based compensation	**3**	3	-	**5**	6	(17)
Total share-based compensation	**35**	17	106	**44**	31	42

The 7% decrease in total G&A expenditures compared to Q2 2017 is a result of the Company focusing on limiting discretionary spending, when possible. G&A expenditure increased 8% from the prior quarter as rent expense increased due to terms of the new head office lease taking effect. The company moved the head office to a new location this spring that included a rent free period followed by a lower monthly cost than the previous lease.

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries. Options granted in July of 2015 and June of 2017 vest conditionally based on certain performance criteria on their first, second and third anniversaries. The increase in share-based compensation expense reflects the issuance of the June 2017 option grant.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
PNG – Australia	**501**	624	(20)	**988**	1,285	(23)
Corporate	**4**	5	(20)	**8**	10	(20)
Total	**505**	629	(20)	**996**	1,295	(23)
$/boe – PNG Australia	**14.22**	17.55	(19)	**14.36**	17.18	(16)

Depletion per barrel decreased from Q2 fiscal 2017 due to a 14% increase in the Company's 2P reserve volumes compared to the prior year as well as a material decrease in the expected future costs associated with developing these reserves. Depletion per barrel is in line with the prior quarter.

Finance Income/Expenses

Finance Income/Expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2017	2016	% Change	**2017**	**2016**	% Change
Interest income	**4**	2	100	**10**	**3**	233
Accretion expense on decommissioning liabilities	**(9)**	(9)	-	**(19)**	**(17)**	12
Letter of credit charges	**-**	(7)	(100)	**-**	**(55)**	(100)
Interest on notes credit facility	**(230)**	(251)	(8)	**(472)**	**(513)**	(8)
Total	**(235)**	(265)	(11)	**(481)**	**(582)**	(17)

Interest on the credit facility is based on US dollar Libor + 3.2% margin.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Geological and geophysical	**183**	205	(11)	**425**	456	(7)
Drilling	**21**	2,969	(99)	**(64)**	2,969	(102)
Completions	**1,323**	146	806	**1,869**	278	572
Total expenditures	**1,527**	3,320	(54)	**2,230**	3,703	(40)
Exploration & evaluation Expenditures	**91**	109	(17)	**230**	241	(5)
Development & production Expenditures	**1,436**	3,211	(55)	**2,000**	3,462	(42)
Total net expenditures	**1,527**	3,320	(54)	**2,230**	3,703	(40)

Development expenditures during the quarter related primarily to the completion of wells drilled in the Cuisinier fiscal 2017 drilling program. Capital expenditures are down from Q2 fiscal 2017 as there are no wells being drilled currently.

CREDIT FACILITY

In October 2014, Bengal closed its US $25.0 million secured credit facility with Westpac Institutional Bank ("Westpac") and placed an initial draw on November 12, 2014 of US $14.0 million. On August 26, 2016 following a US $1.5 million repayment, the Company extended the credit facility by 18 months to December 2018 with a borrowing base of US $15 million. On September 25, 2017, the Company extended the credit facility to December 2019 with a borrowing base of US $12.5 million. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US Libor plus 3.2%. Based on the extension, the Company is committed to extending its hedge contracts through December 2019 prior to June 30, 2018.

The credit facility is structured as a reserves-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. The reduction schedule commences on June 30, 2018 and occurs every six months thereafter until December 31, 2019 with a nominal reduction of US $2.5 million to the facility limit at each calculation date (through June 30, 2019) based on the Company's existing reserve profile and a nominal reduction of US $5 million at December 31, 2019. The facility limit at September 30, 2017 is US $12.5 million, of which US $12.5 million is currently drawn.

The credit facility's reserve based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the credit facility. The Company was in compliance with the stated covenants at September 30, 2017.

SHARE CAPITAL

At November 8, 2017, there were 102,266,694 common shares issued and outstanding, together with 5,488,647 outstanding options.

Trading History	Three Months Ended September 30			Six Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
High	**$ 0.14**	$ 0.23	(39)	**$ 0.17**	$ 0.23	(26)
Low	**$ 0.09**	$ 0.16	(44)	**$ 0.09**	$ 0.11	(18)
Close	**$ 0.13**	$ 0.18	(28)	**$ 0.13**	$ 0.18	(28)
Volume (000s)	**3,227**	1,364	137	**6,596**	5,163	28
Shares outstanding (000s)	**102,267**	68,178	50	**102,267**	68,178	50
Weighted average shares outstanding (000s) Basic & Diluted	**102,267**	68,178	50	**102,267**	68,178	50
Diluted	**102,267**	68,178	50	**102,267**	68,178	51

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of accounts payable and accrued liabilities, and credit facility which amounted to $17.6 million at September 30, 2017 (March 31, 2017 - $18.1 million).

At September 30, 2017 the Company had working capital of $2.1 million, including cash and cash equivalents of $4.0 million and restricted cash of $0.1 million, compared to working capital of $3.8 million at March 31, 2017 and working capital of $4.4 million at September 30, 2016. The Company has no available undrawn debt capacity under its Westpac credit facility.

The majority of the Company's oil sales are benchmarked on dated Brent prices which averaged US $50.97/bbl for the six months ended September 30, 2017. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of low crude prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts (as required by Westpac) to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where appropriate. Under the current commodity price environment, the Company has no plans to use its internal source of cash to fund exploration activities. These are expected to be financed through farm-out or alternative financing sources.

The table below indicates the payment schedule for the credit facility:

Credit facility (US$000s)	
Fiscal year 2018	-
Fiscal year 2019	5,000
Fiscal year 2020	7,500
	12,500

COMMITMENTS

The Queensland Government regulatory authority granted the Company the Authority to Prospect 934 ("**ATP 934**") under a revised work program on March 1, 2015. The Company acquired an additional 21.43 % working interest and received ministerial approval for the acquisition on August 11, 2015. Currently, the Company holds a 71.43% operating interest in this permit. Work program consists of 200 kilometers of 3D seismic and up to three wells, which would require a discretionary capital expenditure of $2.8 million in 2018 net to Bengal.

AFE commitments are reflected where the Company has agreed with partners to proceed with activities (e.g. onshore Australia ATP 752 Cuisinier). The costs of these activities are based on minimum work budgets included in bid documents and agreements among joint venture parties, and have not been provided for in the financial statements. Actual costs will vary from budget.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 934P	200 km^2 of 2D seismic and up to three wells	March 2021	$11.5
Onshore Australia – ATP 752P	Barta West 3D seismic program	February 2018	$1.5

(1) Translated at September 30, 2017 at an exchange rate of AUS $1.00 = CAD $0.9760.

OTHER

At September 30, 2017, the contractual obligations for which the Company is responsible are as follows:

Contractual Obligations ($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 944	$ 129	$ 311	$ 311	$ 193
Decommissioning obligations	1,352	-	224	102	1,026
Total contractual obligations	$ 2,296	$ 129	$ 535	$ 413	$ 1,219

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

($000s, except per share amounts)

Fiscal quarter	**Sep. 30 2017** **Q2 2018**	Jun. 30 2017 Q1 2018	Mar. 31 2017 Q4 2017	Dec. 31 2016 Q3 2017	Sep. 30 2016 Q2 2017	Jun. 30 2016 Q1 2017	Mar. 31 2016 Q4 2016	Dec.31 2015 Q3 2016
Petroleum and natural gas sales	**2,410**	2,306	2,179	2,325	2,301	2,489	2,253	1,838
Cash from operations	**648**	1,690	643	934	1,982	956	1,496	935
Funds from operations	**110**	1,834	1,639	1,412	1,797	1,348	1,439	105
Per share								
Basic and diluted (1)	**0.00**	0.02	0.02	0.02	0.03	0.02	0.02	0.00
Net income (loss)	**(500)**	549	1,931	(2,288)	325	(2,736)	(11,704)	1,413
Per share								
Basic and diluted	**0.00**	0.01	0.02	(0.03)	0.00	(0.04)	(0.17)	0.02
Capital expenditures	**1,527**	703	681	1,234	3,320	383	332	1,311
Working capital (deficiency)	**2,107**	(2,477)	3,815	3,291	4,421	(9,171)	(420)	(1,487)
Total assets	**56,032**	57,104	57,706	56,020	55,552	54,108	58,903	72,353
Shares outstanding (000s)	**102,267**	102,267	102,267	102,267	68,178	68,178	68,178	68,178
Operations								
Oil Volumes (bpd)	**383**	369	344	355	386	431	469	439
Netback ($/boe)	**27.21**	78.02	81.09	69.01	67.30	56.09	58.75	27.54

(1) See “Non-IFRS Measurements” on page 6 of this MD&A.

Production over the last eight quarters peaked during Q4 2016 as incremental production from the fiscal 2016 fracture stimulation program came on stream. Production has increased for the past two quarters as wells from the Cuisinier fiscal 2017 drilling campaign have now been put on stream. Variances in net income have been impacted by unrealized gains/losses on foreign exchanges and derivative contracts as well as material impairments recorded in Q4 fiscal 2016.

Fluctuations in netbacks have been primarily driven by volatile benchmark crude prices and associated hedging gains and losses as royalties and operating/transportation costs have remained consistent. Joint Venture audit proceeds received during Q1 fiscal 2018 contributed to increased funds from operations and cash flows in that period.

DISCLOSURE CONTROLS & PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and includes controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

The Chief Executive Officer and Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and Chief Financial Officer have individually signed certifications to this effect.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at September 30, 2017 due to the material weaknesses noted below.

No changes in internal controls over financial reporting were identified during the period that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

While Bengal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design and operating effectiveness assessment, certain material weaknesses in internal controls over financial reporting were identified, as follows:

- Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general and administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs; and
- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advice on complex financial accounting issues and for tax planning, tax provision and compilation of corporate tax returns.

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates, which are reviewed on an ongoing basis. A full discussion of the Company's critical judgments and accounting estimates is included in its 2017 annual Management's Discussion and Analysis.

NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

Standards that are issued but not yet effective and that the Company reasonably expects to be applicable at a future date are listed below.

Revenue from contracts with customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers". It replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Retrospective application of this standard was to be effective for fiscal years beginning on or after January 1, 2017, with earlier application permitted. On May 19, 2015, the IASB published the expected exposure draft aimed at deferring the effective date of IFRS 15 "Revenue from Contracts with Customers" to January 1, 2018. The Company is currently assessing the impact of this standard.

Financial instruments: recognition and measurement

In July 2014, IFRS 9 "Financial Instruments" was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The Company is currently assessing the impact of this standard.

Leases

On January 13, 2016 the IASB issued IFRS 16 "Leases". The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on April 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

RISK FACTORS

There are a number of risk factors facing companies that participate in the oil and gas industry. A complete list of risk factors are provided in Bengal's Annual Information Form dated June 22, 2017 filed on SEDAR at www.sedar.com.

Bengal monitors and updates its cash projection models on a regular basis which assists in the timing decision of capital expenditures. Farm outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that Bengal wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal's capital program.

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd., Suite 2000, 715 5th Avenue SW., Calgary, Alberta T2P 2X6, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

Forward-looking Statements - *Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward-looking statements. These statements relate to future events or Bengal's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon.*

In particular, this Management's Discussion and Analysis, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *The expected timing of the completion and tie-ins of the successful 5 well at Barta Block Cuisinier*
- *Timing of the finalization of the credit facility extension*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *The Company expects netbacks to remain above $35/bbl under current market conditions;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs; and*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements.*

With respect to the forward looking statements contained in the MD&A, Bengal has made assumptions regarding: future commodity prices; the impact of royalty regimes; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital; the continued availability of undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continued stability of political, regulatory; tax and fiscal regimes in which the Company has operations.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis:

- *Volatility in market prices for oil and natural gas;*
- *Liabilities inherent in oil and natural gas operations;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Unable to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*

- *Changes in income tax laws or changes to royalty and environmental regulations relating to the oil and gas industry;*
- *The risk that Bengal may not be successful in raising funds by an equity issue; and*
- *Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.*

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, which the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Bengal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. Additional information on these and other factors that could affect Bengal's operations and financial results are included in reports on file with Canadian securities authorities and may be accessed through the SEDAR website (www.sedar.com) and at Bengal's website (www.bengalenergy.ca).

These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Johnson Winter Slattery • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

INVESTOR RELATIONS

5 Quarters Investor Relations, Inc. • Calgary, Canada

DIRECTORS

Chayan Chakrabarty
Peter D. Gaffney
James B. Howe
Dr. Brian J. Moss
Robert D. Steele
Ian J. Towers (Chairman)
W.B. (Bill) Wheeler

DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

James B. Howe (Chairman)
Robert D. Steele
W.B. (Bill) Wheeler

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Dr. Brian J. Moss

GOVERNANCE AND COMPENSATION COMMITTEE

Peter D. Gaffney
Dr. Brian J. Moss
Robert D. Steele (Chairman)
Ian J. Towers

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Scott Megaffin, Chief Financial Officer
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG