International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended September 30, 2018 and 2017

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Bengal Energy Ltd. ("Bengal" or the "Company") is at and for three months and six months ended September 30, 2018.

This MD&A should be read in conjunction with the Company's reviewed September 30, 2018 consolidated financial statements. The consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The functional currency of the Company's operating subsidiary is in Australian dollars; the functional currency of the Company is the Canadian dollar ("CAD"). The Company's presentation currency is the CAD. In this MD&A, all dollar amounts are expressed in CAD unless otherwise noted.

This MD&A contains non-IFRS measures, abbreviations and forward-looking information relating to future events and the Company's future performance. Please refer to "Non-IFRS Measures", "Abbreviations" and "Advisories" sections at the end of this MD&A for further information.

Additional information relating to Bengal, including Bengal's audited March 31, 2018 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months and six months ended September 30, 2018 and comparative date to previous year quarter and six month year to date may be referred to as "second quarter fiscal 2019", "Q2 FY 2019", "second quarter fiscal 2018" and "Q2 FY 2018", respectively.

SECOND QUARTER FISCAL 2019 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $3.3 million in the second quarter of fiscal 2019, which is 38% higher than the $2.4 million recorded in fiscal Q2 2018 and 3% higher than fiscal Q1 2019, mainly due to increased US Brent pricing.
- **Hedging** – For the period April 2018 through December 2018, Bengal has 65,261 barrels ("bbls") hedged, using both puts and swaps at US$47/bbl. In addition, the Company hedged 15,906 bbls for the period January 2019 to March 2019 using both puts and swaps at US$55.40/bbl. For the period April 2019 to June 2019, the Company hedged three tranches of 5,000 bbls (15,000 bbls) using swaps at $73.28, $72.92 and $72.58, respectively. Finally, for the period July 2019 to September 2019, the Company hedged three tranches of 5,000 bbls (15,000 bbls) using swaps at US$75.03, US$74.69 and US$74.37 respectively. This hedging program is required under the Company's credit facility.
- **Funds Flow from Operations** – Bengal generated funds flow from operations of $0.8 million in the current quarter, which is a 582% increase from the $0.1 million generated in the second quarter fiscal 2018. The primary reason for the increased funds flow performance in Q2 fiscal 2019 was the significant improvement in cash generated by operations due to the increase in US Brent pricing.
- **Net Income (Loss)** – Bengal reported a net loss of $0.7 million for the current quarter compared to net loss of $0.5 million in the second quarter fiscal 2018.
- **Adjusted Net Earnings –** Bengal reported a net loss of $0.7 million for the current quarter fiscal 2019. Adjusting the net loss for unrealized gain on financial instruments, the unrealized foreign exchange loss for the period and the non-cash impairment of non-current assets, the adjusted net earnings is $0.4 million for the second quarter fiscal 2019.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 26,870 bbls, which is a 24% decline from the 35,233 bbls produced in the second quarter fiscal 2018. The current quarter production averaged 292 bbls per day compared to 383 bbls per day produced in the second quarter 2018. Unplanned operation downtime, normal production declines and reduced capital spending are the reason for the reduction in production for year over year results.
- **Exploration –** The Chookola structure in the southwest section of Cuisinier was drilled during the second quarter fiscal 2019. Although oil was found, it was determined that the quantity was not sufficient to make the well commercial. As a result, all associated costs were impaired in the amount of $0.8 million.

- **Development –** In August of 2018, the Cuisinier North-1, Shefu and Cuisinier-24 wells were fracture stimulated. These wells were brought online in September 2018 with encouraging preliminary improvements observed in production rates. Results will be determined in the coming months.

Bengal's producing and non-producing assets are situated in Australia's Cooper Basin, a region featuring large accumulations of very light and high quality crude oil and natural gas. The Company's core Australian assets: Barrolka, Cuisinier and Tookoonooka are situated within an area of the Cooper Basin that is well served with production infrastructure and take away capacity for produced crude oil and natural gas. Still in early stages, in terms of appraisal and development, Bengal believes these assets offer attractive upside potential for both oil and gas. Australia presents a stable political, fiscal and economic environment in which to operate, and a favourable royalty regime for oil and gas production.

OUTLOOK

AUSTRALIA – Cooper Basin, Queensland

ATP 752 Barta Block Cuisinier (30.357% WI)

During the second half of calendar 2018, the Company's joint venture on ATP 752 Barta Block Cuisinier (the "Joint Venture") initiated a fracture stimulation campaign on three wells. In August of 2018, the Cuisinier North-1, Shefu and Cuisinier-24 wells were fracture stimulated. These wells were brought online in September 2018 with encouraging preliminary improvements observed in production rates. Prior to the frac program, the aggregate gross production from these three wells was 93 bbls/d. Subsequent to the frac program, the aggregate initial production was 322 bbls/d, for an incremental increase of 229 gross bbls/d (an incremental 69 bbls/d net to Bengal). These are preliminary, post frac rates and the performance of these wells will be monitored closely over the coming months. Planning for the stimulation of a fourth well, Cuisinier-19 is complete, with frac operations expected to take place in calendar Q1 2019.

Ongoing evaluation of previously stimulated wells has assisted the Joint Venture in planning for its next drilling campaign, which will allow for fracture stimulations to occur upon completion as required. This will result in operational efficiencies and cost savings in addition to potentially improved initial production rates on the stimulated wells.

The Joint Venture has now completed the selection of drilling locations for the 2019 drilling program. This program will consist of four development and one appraisal well within PL303. The goal of this program is to add production, expand the Cuisinier pool area and thus increase reserves. In addition, the planned program will also complement future waterflood expansion phases currently in the initial planning stages.

The Joint Venture has initiated the implementation of a pilot pressure maintenance scheme, which is planned for implementation early in calendar 2019. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier-24 well. Injection of produced formation water should generate a positive response in performance of up to four offsetting producing wells.

In addition to the above highlighted development activities, the Joint Venture has also agreed upon a contingent, near field exploration well at a location yet to be confirmed. This well would be a sixth well in the 2019 campaign currently planned for Q2/Q3 of calendar 2019.

ATP 934 Barrolka (100% WI)

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 most favourable areas of the permit allowing for additional detailed geophysical work. This includes the reprocessing of select 2D seismic lines that may require additional reprocessing and the potential acquisition of 3D seismic later in calendar 2019. The Company is encouraged by recent natural gas discoveries near the Barrolka permit which suggest the presence of stratigraphically trapped, as well as conventionally trapped, natural gas in the Permian Toolachee and Patchawarra sandstone reservoirs.

Bengal has consolidated its ownership to 100% working interest in the permit through the acquisition of the remaining non-owned interest and now has operatorship. Discussions are ongoing with third parties who may have an interest in farming in on this block, supporting the next phase of exploration thereby further de-risking the natural gas potential of the permit.

ATP 732 Tookoonooka Block (100% WI)

The Tookoonooka Permit (ATP 732 – 100% WI effective January 28, 2016) is located along the oil prone east flank of the Cooper Basin. The Company made application for the required regulatory relinquishment of 1/3 of the block and filed a revised Later Work Program ("LWP") application covering the period 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. The Company is currently in discussion with a third party who has expressed interest in potentially farming in to the permit.

ATP 752 Wompi (38.08% WI)

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 ("PCA 155"), 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. The approved future work program for PCA 155 called for an extended production test of the Nubba well to be conducted during the first 5-year term of the PCA. Bengal is working with the operator to define the detailed timeline for conducting the extended production test.

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. A LWP application was successfully lodged and the permit has now been continued for a further five years to March of 2023. The operator continues to reprocess existing 3D seismic data and evaluate commercialization options.

OPERATING SUMMARY

($000s except per share, %, volumes and netback amounts)	Three months ended September 30		Six months ended September 30	
	2018	2017	2018	2017
Oil revenue	$ 3,315	$ 2,410	$ 6,530	$ 4,716
Realized (loss) gain on financial instruments	$ (430)	$ (69)	$ (845)	$ 1,054
Royalties	$ 273	$ 144	$ 391	$ 283
% of revenue	8	6	6	6
Operating	$ 1,011	$ 1,238	$ 2,080	$ 1,908
Operating netback(1)	$ 1,601	$ 959	$ 3,214	$ 3,579
Cash from operations	$ 603	$ 648	$ 1,622	$ 2,338
Funds from operations(2)	$ 750	$ 110	$ 1,625	$ 1,944
Per share ($) (basic and diluted)	$ 0.01	$ 0.00	$ 0.02	$ 0.02
Net (loss) income	$ (728)	$ (500)	$ (1,214)	$ 49
Per share ($) (basic and diluted)	$ (0.01)	$ 0.00	$ (0.01)	$ 0.00
Adjusted net earnings(3) (loss)	$ 350	$ (364)	$ 777	$ 904
Per share ($) (basic and diluted)	$ 0.00	$ 0.00	$ 0.01	$ 0.01
Capital expenditures	$ 1,274	$ 1,527	$ 1,575	$ 2,230
Oil volumes (bbl/d)	292	383	305	376
Netback(1)($/bbl)	$ 59.58	$ 27.21	$ 57.59	$ 52.01

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

(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 earnings and adjusted net earnings 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 18.

RESULTS OF OPERATIONS

Production

	Three months ended September 30		Six months ended September 30	
	2018	**2017**	**2018**	**2017**
Oil production (bbls/d)	292	383	305	376
Oil production (bbls)	26,870	35,233	55,808	68,811

Pricing

The price received for Bengal's Australian oil sales is benchmarked on US Brent 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 on July 1, 2017.

Realized crude oil price during the second quarter fiscal 2019 was $123.37/bbl, an increase of 80% compared to the prior quarter and the second quarter fiscal 2018. The increases are due to the strengthening US Brent commodity price on a year-over-year basis.

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

	Three months ended September 30		Six months ended September 30	
	2018	**2017**	**2018**	**2017**
Bengal realized crude oil price before realized (loss) gain on financial instruments ($/bbl)	123.37	68.40	117.01	68.54
Realized gain (loss) on financial instruments ($/bbl)	(16.00)	(1.96)	(15.14)	15.32
Brent oil ($/bbl)	98.28	65.14	97.22	66.21
Brent oil (US$/bbl)	75.22	52.11	74.86	50.97
Number of CAD$ for 1 AUS$	0.98	0.99	0.97	1.00
Number of CAD$ for 1 US$	1.29	1.25	1.30	1.30

During the second quarter fiscal 2019, two factors contributed to the Company's realized crude oil price per barrel of $123.37. The primary factor was the strong underlying US Brent price for Q2 FY 2019. The weighted average per barrel realized US Brent price to the Company on the oil lifted during the quarter was US$80.57 including the premium portion to Brent as compared to a weighted average US$54.90/bbl in Q2 FY 2018. The second was the adjustment on the recognized price for approximately 2,512 bbls that was removed from the purchasers' oil stock on hand at Port Bonython during Q2 FY 2019 in addition to the base sales of 26,870 barrels. As a result, the base sales contributed approximately $113/bbl and the additional stock removal added approximately an additional $10/bbl.

($000s)

Netbacks

	Three months ended September 30		Six months ended September 30	
	2018	**2017**	**2018**	**2017**
Oil sales	3,315	2,410	6,530	4,716
Realized (loss) gain on financial instruments	(430)	(69)	(845)	1,054
Royalties	273	144	391	283
Operating expenses	1,011	1,238	2,080	1,908
Netback	1,601	959	3,214	3,579
($/bbl)				
Oil sales[1]	123.37	68.40	117.01	68.54
Realized (loss) gain on financial instruments	(16.00)	(1.96)	(15.14)	15.32
Royalties	10.16	4.09	7.01	4.11
Operating expenses	37.63	35.14	32.27	27.74
Netback[1]	59.58	27.21	57.59	52.01

(1) Includes $10/bbl related to adjustment on stock removal.

The following factors affected the netbacks in the second quarter fiscal 2019: improved average US Brent oil pricing of $74.50/bbl in the second quarter fiscal year 2019 compared to $52.11/bbl in the second quarter fiscal 2018; second, the Company continues to be negatively impacted by the current hedging program as compared to the second quarter fiscal year 2018; operating costs of $1.0 million for second quarter fiscal 2019 are lower than the $1.2 million in the second quarter fiscal 2018 primarily due to lower production. The Company has however seen several rate increases related to the transportation charges that have been passed along by the operator. These variable transportation rate increases explain the higher operating cost per barrel quarter over quarter despite the lower production.

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. It is a requirement under Bengal's credit facility to hedge 50% of its annual production.

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 loss.

The Company has the following derivative contracts:

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
October 1, 2018 – December 31, 2018	Oil - swap	10,764	47.00	47.00
October 1, 2018 – December 31, 2018	Oil – put option	3,883	47.00	-

(000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(471)	-	(471)
Non-current fair value of financial instruments	-	-	-
	(471)	-	(471)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
January 1, 2019 – March 31, 2019	Oil - swap	7,953	55.40	55.40
January 1, 2019 – March 31, 2019	Oil – put option	7,953	55.40	-

(000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(252)	1	(251)
Non-current fair value of financial instruments	-	-	-
	(252)	1	(251)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
April 1, 2019 – April 30, 2019	Oil - swap	5,000	73.28	73.28

(000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(40)	-	(40)
Non-current fair value of financial instruments	-	-	-
	(40)	-	(40)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
May 1, 2019 – May 31, 2019	Oil - swap	5,000	72.92	72.92

(000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(40)	-	(40)
Non-current fair value of financial instruments	-	-	-
	(40)	-	(40)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
June 1, 2019 – June 30, 2019	Oil - swap	5,000	72.58	72.58

(000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(46)	-	(46)
Non-current fair value of financial instruments	-	-	-
	(46)	-	(46)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
July 1, 2019 – July 31, 2019	Oil - swap	5,000	75.03	75.03

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(22)	-	(22)
Non-current fair value of financial instruments	-	-	-
	(22)	-	(22)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
August 1, 2019 – August 31, 2019	Oil - swap	5,000	74.69	74.69

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(21)	-	(21)
Non-current fair value of financial instruments	-	-	-
	(21)	-	(21)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
September 1, 2019 – September 30, 2019	Oil - swap	5,000	74.37	74.37

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(21)	-	(21)
Non-current fair value of financial instruments	-	-	-
	(21)	-	(21)

The fair value of the financial contracts outstanding as at September 30, 2018 is an estimated liability of $1.0 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 six months ended September 30, 2018, the derivative commodity contracts resulted in a realized loss of $0.8 million (2017 – loss of $1.1 million) and an unrealized loss of $nil million (2017 – loss of $1.3 million).

Royalties

Royalties

	Three months ended September 30		Six months ended September 30	
	2018	**2017**	**2018**	**2017**
Royalty expense ($000s)	273	144	391	283
$/bbl	10.16	4.09	7.01	4.11
% of revenue	8	6	6	6

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 6% of revenue.

Royalties per barrel in the second quarter fiscal 2019 were 8% of revenue versus the normal quarterly charge of 6% of revenue, due to additional royalty charges passed through to the Company in order to make up for a shortfall on charges in the first quarter fiscal 2019. The year to date royalty charge is now at the expected 6% of revenue.

Operating Expenses

($000s)
Operating expenses

	Three months ended September 30		Six months ended September 30	
	2018	**2017**	**2018**	**2017**
Production	187	193	370	(110)
Transportation	824	1,045	1,710	2,018
	1,011	1,238	2,080	1,908
Production - $/bbl	6.96	5.48	6.63	(1.59)
Transportation - $/bbl	30.67	29.66	30.64	29.33
	37.63	35.14	37.27	27.74

Total operating expense is lower at $1.0 million for the second quarter fiscal 2019 compared to $1.2 million for the second quarter fiscal 2018 primarily due to the decline in production. Total operating expenses in the second quarter fiscal 2019 reflect increases in several of the transportation rates being charged by the operator. These additional charges are affecting the operating cost per barrel rate quarter over quarter despite the lower production. Operating costs per barrel in the second quarter fiscal 2019 were $37.63/bbl as compared to $35.14/bbl in the second quarter fiscal 2018.

General and Administrative (G&A) Expenses

($000s) **G&A**	**Three months ended September 30**		**Six months ended September 30**	
	2018	**2017**	**2018**	**2017**
Total G&A	765	684	1,478	1,315
Capitalized G&A	25	73	70	156
Net G&A	740	611	1,408	1,159

G&A expenses in the second quarter fiscal 2019 were $0.74 million as compared to $0.61 million for the second quarter fiscal 2018. The increase in G&A expenses is due to expenditures related to capital market activities and additional non-capitalized salary expenditures.

Share-based Compensation ("SBC")

($000s) **SBC**	**Three months ended September 30**		**Six months ended September 30**	
	2018	**2017**	**2018**	**2017**
Expensed share-based compensation	13	32	43	39
Capitalized share-based compensation	2	3	6	5
	15	35	49	44

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; subject to certain performance criteria, they vest one-third on the first anniversary of the grant date and one-third on each of the following two annual anniversaries.

Depletion and Depreciation (DD&A)

($000s) **DD&A**	**Three months ended September 30**		**Six months ended September 30**	
	2018	**2017**	**2018**	**2017**
Petroleum and natural gas properties	346	501	724	988
Other assets	3	4	6	8
	349	505	730	996
Petroleum and natural gas properties - $/bbl	12.88	14.22	12.97	14.36

Depletion per barrel decreased from Q2 fiscal 2018 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 Expense

($000s) **Finance expense**	**Three months ended September 30**		**Six months ended September 30**	
	2018	**2017**	**2018**	**2017**
Interest income	(1)	(4)	(8)	(10)
Accretion expense on decommissioning and restoration liability	10	9	20	19
Letter of credit charges	-	-	8	-
Interest on credit facility	249	230	492	472
	258	235	512	481

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

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended September 30 2018	2017	Six months ended September 30 2018	2017
Geological and geophysical	34	183	171	425
Drilling	777	21	860	(64)
Completions	463	1,323	544	1,869
	1,274	1,527	1,575	2,230
Exploration and evaluation expenditures	752	91	912	230
Development and production expenditures	522	1,436	663	2,000
	1,274	1,527	1,575	2,230

Exploration and evaluation expenditure of $0.8 million relates to the exploratory well drilled in the Chookola structure in southwest Cuisinier during the second quarter fiscal 2019. The full value of the exploration well was subsequently impaired due to the non-commercial nature of the well.

The development and production expenditure of $0.5 million relates to the three wells fractured in the Cuisinier field during the second quarter fiscal 2019.

CREDIT FACILITY

In October 2014, Bengal closed its US$25.0 million secured credit facility (the "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. On March 5, 2018, the Credit Facility was further amended to delay the majority of principal payments into 2019. The Credit Facility is secured by the Company's producing assets in the Cuisinier field, located in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US Libor plus 3.2%.

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. Under the amendment to the Credit Facility dated March 5, 2018, the Company is required to make a US$1.5 million principal payment on December 31, 2018 and a further US$5.0 million on June 30, 2019 and US$6.0 million on December 30, 2019. In return, the Company agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement, which requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserves-based review by April 30, 2019.

The Credit Facility's reserves-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, 2018.

Management is currently in discussions with Westpac to amend the current repayment terms of the Credit Facility. There would be an adverse impact on the Company's liquidity should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility.

SHARE CAPITAL

Trading history	Three months ended September 30		Six months ended September 30	
	2018	**2017**	**2018**	**2017**
High ($)	0.16	0.14	0.18	0.17
Low ($)	0.09	0.09	0.09	0.09
Close ($)	0.09	0.13	0.09	0.13
Volume (000s)	1,977	3,227	4,737	6,596
Shares outstanding (000s)	102,267	102,267	102,267	102,267
Weighted average shares outstanding (000s) - basic and diluted	102,267	102,267	102,267	102,267

At November 9, 2018, there were 102,266,694 common shares issued and outstanding, together with 4,187,500 outstanding options.

LIQUIDITY RISK 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, the Credit Facility and fair value of financial instruments, amounting to $19.8 million at September 30, 2018 (March 31, 2018 - $19.3 million).

At September 30, 2018, the Company had a $3.4 million working capital deficiency, including cash and short-term deposits of $4.4 million and restricted cash of $0.1 million, compared to working capital of $3.4 million at March 31, 2018 and a working capital deficiency of $2.9 million at June 30, 2018. The working capital deficiency at September 30, 2018 is due primarily to the reclassification of $8.4 million of the $16.1 million Credit Facility as a current obligation.

Management anticipates that required payments will be met out of operating cash flows in addition to alternative forms of capital raising. Management is in discussions with Westpac to amend the current repayment terms of the Credit Facility. There would be an adverse impact on the Company's liquidity should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility. Management acknowledges that uncertainty remains at this time over the Company's ability to meet the required fiscal 2019 Credit Facility repayments.

The majority of the Company's oil sales are benchmarked on dated Brent prices, which averaged US$74.86/bbl for the six months ended September 30, 2018. 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 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. The Company will use a combination of internally generated sources of cash and externally generated sources of cash, such as farm-outs and alternative financing sources to fund its exploration activities through fiscal 2019.

The table below indicates the payment schedule for the Credit Facility:

(US $000s)	
Fiscal year 2019	1,500
Fiscal year 2020	11,000
	12,500

COMMITMENTS

The Queensland Government regulatory authority granted the Company 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. In Q4 fiscal 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS$0.3 million cash and potential future cash payments of up to AUS$1.0 million, which is made up of a AUS$0.2 million on certification by an independent competent person appointed by the buyer of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of first gas to market. The work program consists of 260 kilometers of 3D seismic and three wells.

AFE commitments are reflected where the Company has agreed with joint venture 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 may vary from budget.

Country and permit	**Work program**	**Obligation period ending**	**Estimated expenditure (net) (millions CAD$) (1)**
Onshore Australia – ATP 934P	260 km^2 of 3D seismic and three wells with fracs and casing	February 2021	15.4
Onshore Australia – ATP 732	Geological and geophysical studies	March 2021	0.1

(1) Translated at September 30, 2018 at an exchange rate of AUS$1.00 = CAD$ 0.9307.

At September 30, 2018, the contractual obligations for which the Company is responsible are as follows:

($000s) **Contractual obligations**	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Office lease	815	155	311	321	28
Decommissioning and restoration	1,482	-	345	57	1,080
	2,297	155	656	378	1,108

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2019	Mar 31 2018 Q4 2018	Dec 31 2017 Q3 2018	Sep 30 2017 Q2 2018	Jun 30 2017 Q1 2018	Mar 31 2017 Q4 2017	Dec 31 2016 Q3 2017
Oil sales ($000s)	3,315	3,215	2,783	3,211	2,410	2,306	2,179	2,325
Cash from operations ($000s)	603	1,019	858	431	648	1,690	643	934
Funds from operations (1)($000s)	750	875	525	1,268	110	1,834	1,639	1,412
per share – basic and diluted ($)	0.01	0.01	0.01	0.01	0.00	0.02	0.02	0.02
Net (loss) income ($000s)	(728)	(486)	(12,526)	206	(500)	549	1,931	(2,288)
per share – basic and diluted ($)	(0.01)	0.00	(0.12)	0.00	0.00	0.01	0.02	(0.03)
Capital expenditures ($000s)	1,274	301	939	342	1,527	703	681	1,234
Working capital (deficiency) ($000s)	(3,353)	(2,915)	3,385	(637)	2,107	(2,477)	3,815	3,291
Total assets ($000s)	43,547	44,867	45,714	56,932	56,032	57,104	57,706	56,020
Shares outstanding (000s)	102,667	102,667	102,667	102,667	102,667	102,667	102,667	102,667
Operations:								
Oil volumes (bbls)	292	318	334	354	383	369	344	355
Netback ($/bbl)	59.58	55.69	42.66	63.13	27.21	78.02	81.09	69.01

(1) See “Non-IFRS Measurements” on page 18 of this MD&A.

Production over the last eight quarters peaked during the second quarter fiscal 2018 (calendar Q3 2017) as all wells from the Company’s 2014 and 2016 drilling campaign were on stream. Since this period, there has been no drilling activity to increase production. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since the peak in the second quarter fiscal 2018. Despite lower production of the most recent four quarters, US Brent pricing has steadily increased, resulting in increasing oil sales.

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 June 30, 2018 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;
- 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 of Directors 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 2018 annual Management's Discussion and Analysis.

NEW ACCOUNTING STANDARDS

On April 1, 2018, Bengal retrospectively adopted IFRS *15 Revenue from Contracts with Customers* ("IFRS 15"). There were no adjustments made to the April 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are detailed in Note 12 to the September 30, 2018, unaudited interim consolidated financial statements.

On April 1, 2018, Bengal retrospectively adopted IFRS 9 *Financial Instruments* ("IFRS 9"), which includes new requirements for the classification and measurement of financial assets, a new credit loss impairment model and a new model to be used for hedge accounting for risk management contracts. The Company currently has risk management contracts but does not use hedge accounting. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition.

FUTURE ACCOUNTING STANDARDS

IFRS 16 *Leases*

IFRS 16 *Leases*, which replaces IAS 17 *Leases*, was issued in January 2016. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019. Management is assessing the potential impact of the adoption of IFRS 16 on the Company's financial statements. It is anticipated that IFRS 16 will impact the Company's consolidated statement of financial position. The magnitude of the impact is yet to be determined.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Netbacks, netbacks per share, funds from operations, 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. Netback equals total revenue (including realized (loss) gain on financial instruments) less royalties and operating expenses. Netback per barrel equals netback divided by the applicable number of barrels. Management utilizes these measures for operational performance. Funds from operations is defined as cash from operations before changes in non-cash working capital. 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 plus non-cash impairment of non-current assets. 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 cash flow from operations to funds flow from operations, which is used in this MD&A:

($000s)	Three months ended September 30		Six months ended September 30	
	2018	2017	2018	2017
Cash flow from (used in) operating activities	603	648	1,622	2,338
Changes in non-cash working capital	147	(538)	3	(394)
Funds from operations	750	110	1,625	1,944

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

($000s)	Three months ended September 30		Six months ended September 30	
	2018	2017	2018	2017
Net (loss) income	(728)	(500)	(1,214)	49
Unrealized (loss) gain on financial instruments	(161)	444	19	1,256
Unrealized foreign exchange loss (gain)	429	(308)	1,017	(401)
Non-cash impairment of non-current assets	810	-	955	-
Adjusted net earnings (loss)	350	(364)	777	904

ABBREVIATIONS

The following abbreviations used in this MD&A have the meanings set forth below:

bbl	-	barrel
bbls	-	barrels
bbls/d	-	barrels per day
$/bbl	-	dollars per barrel
FY	-	fiscal year
km	-	kilometres

km^2	-	square kilometres
Q1	-	three months ended June 30
Q2	-	three months ended September 30
Q3	-	three months ended December 31
Q4	-	three months ended March 31
Santos	-	Santos Ltd.
WI	-	working interest
YTD	-	year to date

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, 2018 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 this MD&A constitute forward-looking statements or information ("forward-looking statements") as defined by applicable securities laws. 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 this MD&A should not be unduly relied upon. The projections, estimates and beliefs contained in such forward-looking statements are based on management's estimates, opinions, and assumptions at the time the statements were made, including assumptions relating to: the impact of economic conditions in North America and Australia and globally; industry conditions; changes in laws and regulations including, without limitation, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the availability of qualified operating or management personnel; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and fluctuations in market valuations of companies with respect to announced transactions and the final valuations thereof; results of exploration and testing activities; and the ability to obtain required approvals and extensions from regulatory authorities. Management of the Company believes the expectations reflected in those forward-looking statements are reasonable but, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Bengal will derive from them. As such, undue reliance should not be placed on forward-looking statements.*

In particular, this MD&A contains 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 determining the results of the August 2018 frac program from the Cuisinier North-1, Shefu and Cuisinier-24 wells in the Cuisinier oil field;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *The expected timing of the fracture stimulation on Cuisinier-19;*
- *The expectation that the Joint Venture's drilling campaign will allow for fracture stimulations to occur upon completion as required and result in operational efficiencies, cost savings and improved initial production rates;*
- *The expected timing of the implementation of a pilot pressure maintenance scheme and the potential positive performance response of up to four offsetting producing wells in the Cuisinier field;*
- *The expected timing of a contingent near field exploration well at a yet to be determined location;*
- *The possibility of additional reprocessing and acquisition of 2D and 3D seismic on ATP 934;*

- *The potentially trapped natural gas in the Permian Toolachee and Patchawarra sandstone reservoirs;*
- *The possibility of third parties farming in on ATP 934 Barrolka and ATP 732 Tookoonooka;*
- *The timing of the development and extended production test of the Nubba-1 ATP 752, Wompi Block and Bengal's ability to study Permian gas potential;*
- *The potential pipeline transportation of produced natural gas from ATP 752;*
- *The expectation that the current principal payment schedule under the Credit Facility will be deferred and the potential impact to the Company is the deferral is not approved;*
- *The anticipation that IFRS 16 will impact the Company's consolidated statement of financial position;*
- *Projections of market prices and costs including, but not limited to, expected royalty rates;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *Bengal's ability to finance its working capital deficiency and to source funds for the same;*
- *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, share issuances or other alternative forms of capital raising and funds will be sufficient to meet requirements including but not limited to Bengal's exploration activities through fiscal 2019 and capital program.*

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause Bengal's actual results, performance or achievement to differ materially from those expectations expressed in, or implied by, these forward-looking statements, including but not limited to, risks associated with:

- *Fluctuations in commodity prices, foreign exchange or interest rates;*
- *Liabilities inherent in oil and natural gas operations;*
- *The failure to obtain required regulatory approvals or extensions;*
- *The failure to satisfy the conditions under farm-in and joint venture agreements;*
- *The failure to secure required equipment and personnel;*
- *Changes in general global economic conditions including, without limitations, the economic conditions in North America and Australia;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Increased competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *The availability of qualified operating or management personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Inability to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Bengal's development and exploration opportunities;*
- *The results of exploration and development drilling and related activities;*
- *Changes in laws and regulations including, without limitation, the adoption of new environmental, royalty and tax laws and regulations and changes in how they are interpreted and enforced;*
- *The ability to access sufficient capital from internal and external sources; 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 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).

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CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, 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

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

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
Matthew Moorman, Chief Financial Officer
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG