International exploration & production

Management's Discussion & Analysis

Three and Nine Months Ended
December 31, 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 nine months ended December 31, 2018.

This MD&A should be read in conjunction with the Company's December 31, 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 the Australian dollar; 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 nine months ended December 31, 2018 and comparative previous year quarter and nine month year- to-date may be referred to as "third quarter fiscal 2019", "Q3 FY 2019", "third quarter fiscal 2018" and "Q3 FY 2018", respectively.

THIRD QUARTER FISCAL 2019 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $2.0 million in the third quarter of fiscal 2019, which is 37% lower than the $3.2 million recorded in Q3 fiscal 2018 and 39% lower than Q2 fiscal 2019, mainly due to a decline in US Brent pricing and oil production.
- **Hedging** – The Company's credit facility requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. The quarter ended December 31, 2018 was burdened with a hedge of US$47/bbl. The quarter ending March 31, 2019 has hedges in place at $US 55.40/bbl while the two subsequent quarters have a portion of expected production hedged at over $US 72/bbl. For the quarter ending December 31, 2019 a portion of production has been hedged using puts and swaps at $US 54.20/bbl.
- **Funds from Operations** – Bengal generated a use of funds from operations of $0.2 million in the current quarter, a $1.5 million decline from the $1.3 million funds from operations generated in the third quarter fiscal 2018. The primary reason for the decrease in funds performance in Q3 fiscal 2019 was the significant decline in US Brent pricing.
- **Net Income** – Bengal reported net income of $0.9 million for the current quarter compared to net income of $0.2 million in the third quarter fiscal 2018. The primary driver for this positive result was the positive change in the unrealized gain on financial instruments which resulted from lower oil priced that were entered into to hedge the Company's oil pricing.
- **Adjusted Net Loss –** Bengal reported net income (loss) of $0.9 million for the current quarter. Adjusting the net income 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 loss is $0.6 million for the third quarter fiscal 2019 compared to $0.7 million adjusted net income for Q3 fiscal 2018.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 27,593 bbls, which is a 15% decline from the 32,594 bbls produced in the third quarter fiscal 2018. The current quarter production averaged 300 bbls per day compared to 354 bbls per day produced in the third quarter 2018 and 292 bbls per day produced in the second quarter fiscal 2019. Normal production declines and reduced capital spending are the reason for the reduction in production for year over year. Production increased sequentially as increased volumes from fracturing in the December quarter more than offset normal sequential declines.
- **Development -** The development and production expenditures of $0.3 million primarily relates to the connect costs related to the fracking of our Cuisinier-19 well during the current quarter.

MANAGEMENT'S DISCUSSION AND ANALYSIS – February 12, 2019

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.

Business Overview:

Under the State of Queensland Regulatory process, ATP's (Authority's to Prospect) are granted by the State generally for a period of twelve years with one third of the original grant area expiring every fourth year. At the end of the final term of the ATP an application can be made to continue a portion of it in the form of a PCA (Potential Commercial Area). PCA's have a life span of five to fifteen years. If a discovery of oil or gas is made an application for a PL (Petroleum Lease) is made to allow for production. PL's are granted for up to a thirty year term. Bengal now has two PL's for the Cuisinier field those being PL 303 and PL 1028. In the case of ATP 752, the end of its term occurred July 31, 2018 and applications for PCA 206 Barta West and PCA 207 Barta West were lodged by the operator.

AUSTRALIA – Cooper Basin, Queensland

PL 303 Barta Block Cuisinier (formerly ATP 752) (30.357% WI)

During the second half of calendar 2018, the Company's joint venture on Barta Block Cuisinier PL 303 (the "Joint Venture") conducted a fracture stimulation campaign on four wells. Three of the four wells were successful and the Cuisinier North-1, Shefu-1 and Cuisinier-24 wells were brought online in September. The Cuisinier-19 well was fracced in a later program during Q3 fiscal 2019 but was unsuccessful. Prior to the frac program, the aggregate gross production from the 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 post frac rates have been monitored closely over the last quarter with positive productivity levels observed. In December 2018, aggregate production from the successful wells was approximately 203 bbls/d (a 118% increase from the pre frac rates). Ongoing evaluation of previously stimulated wells has assisted the Joint Venture in planning for its future drilling campaigns, 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 fiscal 2019 drilling program. This program will consist of four development wells and one appraisal well within PL 303. This drilling campaign started in February of 2019. The goal of the program is to add production, expand the Cuisinier pool area and thus increase reserves. The Joint Venture has also initiated the implementation of a pilot pressure maintenance scheme, which is planned to commence during the second quarter of 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. The broad nature of the Cuisinier structure combined with weak flank aquifer pressure support has resulted in pressure depletion within the central portion of the Cuisinier pool. The injection of produced formation water is anticipated to generate a positive response in production performance of up to four offsetting producing wells. In addition, the planned program will also complement future water flood expansion phases currently in the initial planning stages.

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 which will be valuable in selection of future drilling locations and locating the area of potential 3D seismic acquisition 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 structurally 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 is located along the oil prone east flank of the Cooper Basin. Under the State of Queensland regulatory process, one third of the area contained in ATP 732 must be relinquished every four years, accompanied by the filing of a Later Work Program ("LWP") for the following 4 year term. From the extensive exploration work done to date which includes both 2D and 3D seismic as well as the drilling of two wells, Bengal selected the most promising blocks of land for retention and relinquished the least prospective lands for the first two surrenders. The Company chose the least prospective acreage for relinquishment with the high graded lands remaining. The final relinquishment is scheduled to occur on March 31, 2023. Planning for PCA applications is underway. The work program for the ATP's final term includes the study of 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. The Company will continue to seek interest from third parties regarding the potential of this permit.

Potential Commercial Area 155 Nubba/Yilgarn Wompi (formerly ATP 752) (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 which will be announced when the timing has been confirmed. There were no further developments during Q3 fiscal 2019.

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 2023. The operator continues to reprocess existing 3D seismic data and evaluate commercialization options. There were no further developments during Q3 fiscal 2019.

OPERATING SUMMARY

($000s except per share, %, volumes and netback amounts)	Three months ended December 31				Nine months ended December 31			
		2018		2017		2018		2017
Oil revenue	$	2,014	$	3,211	$	8,544	$	7,927
Operating netback[(1)]	$	622	$	2,057	$	3,836	$	5,636
Cash from operations	$	434	$	431	$	2,056	$	2,769
Funds (used in) from operations[(2)]	$	(247)	$	1,268	$	1,378	$	3,212
Per share ($) (basic and diluted)	$	0.00	$	0.01	$	0.01	$	0.03
Net income (loss)	$	883	$	206	$	(331)	$	255
Per share ($) (basic and diluted)	$	0.01	$	0.00	$	0.00	$	0.00
Adjusted net income (loss)[(3)]	$	(649)	$	698	$	128	$	1,602
Per share ($) (basic and diluted)	$	(0.01)	$	0.01	$	0.00	$	0.02
Capital expenditures	$	298	$	342	$	1,873	$	2,572
Oil volumes (bbl/d)		300		354		303		369
Netback[(1)]($/bbl)	$	22.54	$	63.12	$	45.99	$	55.58

(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 (loss) on financial instruments) less royalties and operating costs by the total production of the Company measured in bbls. A reconciliation of the measures can be found in the table on page 8 of Bengal's management's discussion and analysis for the three and nine months ended December 31, 2019.

(2) Funds from operations per share is a non-IFRS measure calculated as calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed. A reconciliation of the measures can be found in the table on page 18 of Bengal's management's discussion and analysis for the three and nine months ended December 31, 2019.

(3) Adjusted net income (loss) and adjusted net income (loss) 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 of Bengal's management's discussion and analysis for the three and nine months ended December 31, 2019.

(4) The above non-IFRS measures do not have any standardized meaning under Bengal's GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

RESULTS OF OPERATIONS

Production	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Oil production (bbls/d)	300	354	303	369
Oil production (bbls)	27,593	32,594	83,401	101,405

Revenue/Pricing

The following table outlines bills of lading for shipped oil, pipeline oil estimates, applicable prices and oil sales reflected in the Company's financials:

	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Revenue from oil lifting ($000's)	2,437	3,094	9,629	7,475
% change in price from oil lifting	(25%)	13%	(14%)	31%
Change in revenue from pipeline oil	(423)	117	(1,085)	452
% change in price from pipeline oil	(28%)	21%	(14%)	23%
Total Net Revenue	2,014	3,211	9,544	7,927

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 due to oil quality differences. Pipeline oil is the term used to describe oil moving along the pipeline from the wellhead to the port that has been legally transferred to the buyer but not priced.

Realized crude oil price during the third quarter fiscal 2019 was significantly impacted by the decline in US Brent as compared to second quarter fiscal 2019 and third quarter fiscal 2018. US Brent declined 28% during Q3 fiscal 2019 from US$84.30 down to US$60.31. This material decline negatively impacted the revenue realized by Bengal for oil lifting and on pipeline oil, the two components that make up total revenue. The table above shows that US Brent price realized for the oil lifting revenue decline 25% during the current quarter while the US Brent price used to value pipeline oil from the end of Q2 fiscal 2019 to the end of Q3 fiscal 2019 declined by 28%. This resulted in total net revenue for Q3 fiscal 2019 to be $2.0 million (oil lifting revenue at $2.4 million plus the negative change in pipeline oil of $.4 million). This compares to $3.2 million total revenue realized in Q3 fiscal 2018 (oil lifting revenue of $3.1 million plus positive change in pipeline oil of $.1 million).

The following table outlines average benchmark prices:

	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Brent oil ($/bbl)	89.49	78.14	94.69	70.25
Brent oil (US$/bbl)	67.71	61.53	72.48	54.49
Number of CAD$ for 1 AUS$	0.95	0.98	0.96	0.99
Number of CAD$ for 1 US$	1.32	1.27	1.31	1.29

($000s)

Netbacks

	Three months ended December 31		Nine months ended December 31	
	2018	**2017**	**2018**	**2017**
Oil sales	2,014	3,211	8,544	7,927
Realized (loss) gain on financial instruments	(301)	(198)	(1,146)	856
Royalties	120	223	511	506
Operating expenses	971	733	3,051	2,641
Netback	622	2,057	3,836	5,636
($/bbl)				
Oil sales	72.99	98.52	102.44	78.17
Realized (loss) gain on financial instruments	(10.91)	(6.07)	(13.74)	8.44
Royalties	4.35	6.84	6.13	4.99
Operating expenses	35.19	22.49	36.58	26.04
Netback	22.54	63.12	45.99	55.58

Netbacks in Q3 fiscal 2019 were $0.6 million or $22.54/bbl compared to Q3 fiscal 2018 at $2.1 million or $63.12/bbl. The primary reason for the decline in netback during the current quarter compared to Q3 fiscal 2018 was the 28% decline in US$ Brent pricing which resulted in a 37% decline in revenue. The realized loss on financial instruments is due to the US$47 hedges throughout the nine months ended Q3 fiscal 2019. Royalties were in line with expectations as was the operating expenses for Q3 fiscal 2019 and the nine months ending December 31, 2019. Comparative operating expenses for 2018 were much lower as a result of a significant credit received from a joint venture audit initiated by Bengal as further explained under Operating Expenses below.

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 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
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	21	46	67
Non-current fair value of financial instruments	-	-	-
	21	46	67

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	131	-	131
Non-current fair value of financial instruments	-	-	-
	131	-	131

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	128	-	128
Non-current fair value of financial instruments	-	-	-
	128	-	128

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	125	-	125
Non-current fair value of financial instruments	-	-	-
	125	-	125

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	141	-	141
Non-current fair value of financial instruments	-	-	-
	141	-	141

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	138	-	138
Non-current fair value of financial instruments	-	-	-
	138	-	138

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	136	-	136
Non-current fair value of financial instruments	-	-	-
	136	-	136

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
October 1, 2019 – December 31, 2019	Oil - swap	7,500	54.20	54.20
October 1, 2019 – December 31, 2019	Oil – put option	7,500	54.20	-

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(4)	69	65
Non-current fair value of financial instruments	-	-	-
	(4)	69	65

Total

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	816	115	931
Non-current fair value of financial instruments	-	-	-
	816	115	931

The fair value of the financial contracts outstanding as at December 31, 2018 is $0.9 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 nine months ended December 31, 2018, the derivative commodity contracts resulted in a realized loss of $1.1 million (nine months ended December 31, 2017 – gain of $0.9 million) and an unrealized gain of $1.8 million (nine months ended December 31, 2017 – loss of $1.7 million).

Royalties

Royalties	**Three months ended December 31**		**Nine months ended December 31**	
	2018	**2017**	**2018**	**2017**
Royalty expense ($000s)	120	223	511	506
$/bbl	4.35	6.84	6.13	4.99
% of revenue	6	7	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 third quarter fiscal 2019 were 6% of revenue, consistent with the yearly expected average.

Operating Expenses

($000s) **Operating expenses**	**Three months ended December 31**		**Nine months ended December 31**	
	2018	**2017**	**2018**	**2017**
Production	168	(280)	538	(396)
Transportation	803	1,013	2,513	3,037
	971	733	3,051	2,641
Production - $/bbl	6.09	(8.59)	6.45	(3.91)
Transportation - $/bbl	29.10	31.08	30.13	29.95
	35.19	22.49	36.58	26.04

Total operating expense is higher at $1.0 million for the third quarter fiscal 2019 compared to $0.7 million for the third quarter fiscal 2018 primarily due to the Company realising a credit of $0.6 million against operating costs in Q3 fiscal 2018 found during a routine audit of the operator’s JV billings. No such audit credit was recorded during Q3 fiscal 2019. The operating costs incurred during the current quarter were in line with our forecast and budget. In addition, when higher production in Q3 fiscal 2018 is compared to the production volume in the current quarter (32,594 bbls vs 27,593 bbls), the operating cost per barrel for Q3 fiscal 2018 is lower at 22.49/bbl than the current quarter at $35.19/bbl. These lower costs due to audit credits and higher production volumes for Q3 fiscal 2018 explain the lower cost per barrel in YTD Q3 fiscal 2018 compared to YTD Q3 fiscal 2019.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Total G&A	725	695	2,248	2,010
Capitalized G&A	39	70	154	226
Net G&A	686	625	2,094	1,784

G&A expenses in the third quarter fiscal 2019 were $0.69 million as compared to $0.63 million for the third quarter fiscal 2018 and $2.1 million and $1.8 million respectively. Additional consulting fees and travel expenses contributed to the higher G&A quarter over quarter.

Share-based Compensation (“SBC”)

($000s) SBC	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Expensed share-based compensation	13	28	56	67
Capitalized share-based compensation	1	5	7	10
	14	33	63	77

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 December 31		Nine months ended December 31	
	2018	2017	2018	2017
Petroleum and natural gas properties	352	465	1,076	1,453
Other assets	2	3	8	11
	354	468	1,084	1,464
Petroleum and natural gas properties - $/bbl	12.76	14.27	12.90	14.33

Depletion per barrel in Q3 fiscal 2019 decreased from Q3 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.

Finance Expense

($000s) Finance expense	Three months ended December 31 2018	2017	Nine months ended December 31 2018	2017
Interest income	(1)	(2)	(9)	(12)
Accretion expense on decommissioning and restoration liability	10	9	30	28
Letter of credit charges	-	-	8	-
Interest on credit facility	248	246	740	718
	257	253	769	734

Interest on the Credit Facility is based on US dollar Libor + 3.2% margin. The revised Credit Facility amendment dated November 2018 will increase the margin to 3.75% as at January 1, 2019.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended December 31 2018	2017	Nine months ended December 31 2018	2017
Geological and geophysical	39	128	210	553
Drilling	(30)	12	830	(52)
Completions	289	202	833	2,071
	298	342	1,873	2,572
Exploration and evaluation expenditures	(42)	51	870	281
Development and production expenditures	340	291	1,003	2,291
	298	342	1,873	2,572

The development and production expenditure of $0.3 million primarily relates to the case and connect costs related to the fracking of our Cuisinier-19 well during the current quarter. There was also $0.1 million related to the first waterflood pilot project. The negative amounts reflected in Q3 fiscal 2019 above include a credit received as a result of the operator overbilling Bengal for its share of capital expenditures in Q2 fiscal 2019 relating to the Chookola exploratory well which was fully impaired in Q2 fiscal 2019 due to the non-commercial nature of the well.

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$15.0 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 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%.

The Credit Facility is structured as a reserve-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 was 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 addition, the Company had agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement that requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve-based review by April 30, 2019. Pursuant to these terms, the Company repaid US$131,000 during Q3 fiscal 2019.

On November 19, 2018, the Company and Westpac entered into a revised amendment agreement to the Credit Facility to defer all principal payments previously required under the March 5, 2018 amendment to February 15, 2020. This revised amendment now requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. All other terms and conditions previously provided under the March 5, 2018 amendment remain in effect. There is an interest rate change from 3.2% to 3.75% plus Libor effective January 1, 2019.

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 December 31, 2018.

SHARE CAPITAL

Trading history	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
High ($)	0.12	0.15	0.18	0.17
Low ($)	0.09	0.08	0.09	0.08
Close ($)	0.09	0.08	0.09	0.08
Volume (000s)	2,863	6,057	7,600	12,653
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 February 12, 2019, there were 102,266,694 common shares issued and outstanding, together with 4,102,500 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, and a Credit Facility, amounting to $18.8 million at December 31, 2018 (March 31, 2018 - $19.3 million).

At December 31, 2018, the Company had $6.3 million of working capital, including cash and short-term deposits of $4.0 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 $3.4 million at September 30, 2018.

Notwithstanding the positive working capital and improved financial position at December 31, 2018, the Company has significant spending commitments to be incurred by February 2021 on ATP 934P and has its USD $12.4 million credit facility that matures in February 2020. Management anticipates that required payments will be met out of operating cash flows in addition to alternative forms of capital raising. There can be no guarantees that alternative forms of capital raising will be available or obtained on terms that are satisfactory to the Company.

The majority of the Company's oil sales are benchmarked on dated Brent prices, which averaged US$72.48/bbl for the nine months ended December 31, 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 and beyond.

The table below indicates the payment schedule for the Company's Credit Facility:

(US$000s)	
Fiscal year 2019	-
Fiscal year 2020	12,369
	12,369

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 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 commercial 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, Barta Block Cuisinier PL 303). 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	15.9
Onshore Australia – ATP 732	Geological and geophysical studies	March 2021	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at December 31, 2018 at an exchange rate of AUS$1.00 = CAD$ 0.9613.

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	776	155	311	310	-
Decommissioning and restoration	1,541	-	359	59	1,123
	2,317	155	670	369	1,123

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2019	Mar 31 2018 Q4 2018	Dec 31 2017 Q3 2018	Sep 30 2017 Q2 2018	Jun 30 2017 Q1 2018	Mar 31 2017 Q4 2017
Oil sales	2,014	3,315	3,215	2,783	3,211	2,410	2,306	2,179
Cash from operations	434	603	1,019	858	431	648	1,690	643
Funds (used in) from operations (1)	(247)	750	875	525	1,268	110	1,834	1,639
per share – basic and diluted ($)	0.00	0.01	0.01	0.01	0.01	0.00	0.02	0.02
Net income (loss)	883	(728)	(486)	(12,526)	206	(500)	549	1,931
per share – basic and diluted ($)	0.01	(0.01)	0.00	(0.12)	0.00	0.00	0.01	0.02
Capital expenditures	298	1,274	301	939	342	1,527	703	681
Working capital (deficiency)	6,331	(3,353)	(2,915)	3,385	(637)	2,107	(2,477)	3,815
Total assets	44,291	43,547	44,867	45,714	56,932	56,032	57,104	57,706
Shares outstanding (000s)	102,667	102,667	102,667	102,667	102,667	102,667	102,667	102,667
Operations:								
Oil volumes (bbls)	300	292	318	334	354	383	369	344
Netback ($/bbl)	22.54	59.58	55.69	42.66	63.13	27.21	78.02	81.09

(1) See “Non-IFRS Measurements” on page 17 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 in the most recent four quarters and significant volatility in US$ Brent during Q3 fiscal 2019 US$ Brent pricing had steadily increased throughout the first three quarters of calendar 2018, 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 December 31, 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 December 31, 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. The additional disclosures required by IFRS 9 are detailed in Note 4 to the December 31, 2018, unaudited interim consolidated financial statements.

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 not materially impact the Company's consolidated statement of financial position.

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.

Management believes the presentation of the Non-IFRS measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

The above non-IFRS measures do not have any standardized meaning under Bengal's GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

The following table reconciles cash from operations to funds from operations, which is used in this MD&A:

($000s)	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Cash from (used in) operating activities	434	431	2,056	2,769
Changes in non-cash working capital	(681)	837	(678)	443
Funds (used in) from operations	(247)	1,268	1,378	3,212

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

($000s)	Three months ended December 31 2018	2017	Nine months ended December 31 2018	2017
Net income (loss)	883	206	(331)	255
Unrealized (gain) loss on financial instruments	(1,845)	444	(1,826)	1,700
Unrealized foreign exchange loss (gain)	383	48	1,400	(353)
Non-cash impairment of non-current assets	(70)	-	885	-
Adjusted net (loss) income	(649)	698	128	1,602

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 belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *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 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 relinquishment of ATP 732.*
- *The timing of the development and extended production test of the Nubba-1 PCA 155 Nubba/Yilgarn, Wompi Block and Bengal's ability to study Permian gas potential;*
- *The potential pipeline transportation of produced natural gas from PCA 155 Nubba/Yilgarn;*
- *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;*
- *That required payments will be met out of operation cash flows and alternative forms of capital raising.*
- *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).

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

Interim Consolidated Financial Statements
(unaudited)

Three and Nine Months Ended
December 31, 2018 and 2017

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(unaudited)

As at		December 31 2018	March 31 2018
Assets	Notes		
Current assets:			
Cash and cash equivalents		$ 4,029	$ 3,904
Restricted cash		140	140
Trade and other receivables	4	2,986	4,307
Prepaid expenses and deposits		149	154
Fair value of financial instruments		931	-
		8,235	8,505
Exploration and evaluation assets	5	9,802	10,102
Property, plant and equipment	6	26,254	27,107
Total assets		$ 44,291	$ 45,714
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	7	$ 1,904	$ 2,232
Current portion of credit facility	8	-	1,934
Fair value of financial instruments	16	-	954
		1,904	5,120
Decommissioning and restoration liability	9	1,541	1,556
Credit facility	8	16,916	14,146
		20,361	20,822
Shareholders' equity:			
Share capital	10	98,100	98,100
Contributed surplus		7,818	7,755
Accumulated other comprehensive income		340	1,034
Deficit		(82,328)	(81,997)
		23,930	24,892
Total liabilities and shareholders' equity		$ 44,291	$ 45,714

Commitments (note 18)

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

	Notes	Three months ended December 31 2018	Three months ended December 31 2017	Nine months ended December 31 2018	Nine months ended December 31 2017
Revenue					
Oil sales	12	$ 2,014	$ 3,211	$ 8,544	$ 7,927
Royalties		(120)	(223)	(511)	(506)
		1,894	2,988	8,033	7,421
Realized (loss) gain on financial instruments	16	(301)	(198)	(1,146)	856
Unrealized gain (loss) on financial instruments	16	1,845	(444)	1,826	(1,700)
		3,438	2,346	8,713	6,577
Expenses					
General and administrative		686	625	2,094	1,784
Operating		971	733	3,051	2,641
Depletion and depreciation		354	468	1,084	1,464
Impairment	5	(70)	-	885	-
Share-based compensation		13	28	56	67
Foreign exchange loss (gain)		344	33	1,105	(244)
		2,298	1,887	8,275	5,712
Other expense					
Other		-	-	-	(124)
Finance expense	14	257	253	769	734
Net income (loss)		883	206	(331)	255
Exchange differences on translation of foreign operations		729	127	(694)	(1,476)
Comprehensive income (loss) for the period		$ 1,612	$ 333	$ (1,025)	$ (1,221)
Income (loss) per share - basic & diluted	13	$ 0.01	$ 0.00	0.00	$ 0.00
Weighted average shares outstanding (000s) – basic and diluted	13	102,267	102,267	102,267	102,267

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

(unaudited)

For the nine months ended December 31	2018	2017
Share capital		
Balance at beginning and end of period	$ 98,100	$ 98,100
Contributed surplus		
Balance at beginning of period	7,755	7,645
Share-based compensation – expensed	56	67
Share-based compensation – capitalized	7	10
Balance at end of period	7,818	7,722
Accumulated other comprehensive income (loss)		
Balance at beginning of period	1,034	2,085
Exchange differences translation of foreign operations	(694)	(1,476)
Balance at end of period	340	609
Deficit		
Balance at beginning of period	(81,997)	(69,726)
Net (loss) income	(331)	255
Balance at end of period	(82,328)	(69,471)
Total shareholders’ equity	$ 23,930	$ 36,960

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

(unaudited)

	Notes	Three months ended December 31 2018	Three months ended December 31 2017	Nine months ended December 30 2018	Nine months ended December 30 2017
Operating activities:					
Net income (loss)		$ 883	$ 206	$ (331)	$ 255
Add (deduct) non-cash items					
Depletion and amortization		354	468	1,084	1,464
Accretion on decommissioning ` and restoration liability		10	9	30	28
Accretion on credit facility		25	65	80	175
Gain on disposal		-	-	-	(124)
Share-based compensation		13	28	56	67
Impairment		(70)	-	885	-
Unrealized (gain) loss on financial Instruments		(1,845)	444	(1,826)	1,700
Unrealized foreign exchange loss (gain)		383	48	1,400	(353)
Funds from operations		(247)	1,268	1,378	3,212
Change in non-cash working capital	17	681	(837)	678	(443)
Net cash from operating activities		434	431	2,056	2,769
Investing activities:					
Exploration and evaluation expenditures	5	42	(51)	(870)	(281)
Petroleum and natural gas property expenditures	6	(340)	(291)	(1,003)	(2,291)
Change in non-cash working capital	17	(250)	(720)	280	(456)
Net cash used in investing activities		(548)	(1,062)	(1,593)	(3,028)
Financing activities:					
Repayment of credit facility	8	(176)	-	(176)	-
Facility extension fees		-	-	-	(95)
Change in non-cash working capital	17	(227)	-	(36)	(59)
Net cash used in financing activities		(403)	-	(212)	(154)
Net (decrease) increase in cash and cash equivalents		(517)	(631)	251	(413)
Cash and cash equivalents, beginning of period		4,415	3,968	3,904	3,903
Impact of foreign exchange on cash and cash equivalents		131	10	(126)	(143)
Cash and cash equivalents, end of period		$ 4,029	$ 3,347	$ 4,029	$ 3,347

See accompanying notes to the interim consolidated financial statements.

1. REPORTING ENTITY

Bengal Energy Ltd (the "Company" or "Bengal") is incorporated under the laws of the Province of Alberta and is involved in the exploration, development and production of oil and gas reserves in Australia. The interim consolidated financial statements (the "financial statements") of the Company are comprised of the Company and all its wholly-owned subsidiaries including Bengal Energy Australia (Pty) Ltd., which is incorporated in Australia. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

Bengal's principal place of business and registered office is located at 2000, 715 5th Ave SW, Calgary, Alberta, Canada, T2P 2X6.

2. BASIS OF PREPARATION

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting." These financial statements do not include all of the information required for full annual financial statements.

These financial statements are stated in Canadian dollars and have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company for the year ended March 31, 2018 except as specified in Note 3 below. These financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended March 31, 2018.

The interim consolidated financial statements were approved and authorized for issuance by the Board of Directors on February 12, 2019.

3. CHANGES IN 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.

The Company adopted IFRS 9 with a date of initial application as of April 1, 2018, this is the date in which all IFRS 9 classification and measurement is required to be implemented. The Company retrospectively adopted the standard and elected not to restate comparative information. There were no material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"), or fair value through profit or loss ("FVTPL"). IFRS 9 eliminates the previous IFRS 39 categories of 'held to maturity investments, loans and receivables and other financial liabilities' and 'available for sale financial assets'. The classification of financial assets under IFRS 9 is based on the business model in which a financial asset is managed and the nature of its contractual cash flow characteristics. Embedded derivatives are not separated if the host contract is a financial asset within the scope of IFRS 9; the entire hybrid contract is assessed for classification and measurement.

IFRS 9 replaces the 'incurred credit loss model' in IAS 39 with an 'expected credit loss' model. The new impairment model applies to financial assets measured at amortized cost, a lease receivable, a contract asset or a loan commitment and a financial guarantee contract. Under IFRS 9, credit losses are recognized earlier than under IAS 39; it is no longer necessary for a credit event to have occurred before credit losses are recognised.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at April 1, 2018 for each class of the Company's financial assets and financial liabilities. The Company has no contract assets or financial instruments measured at FVOCI. The transition to IFRS 9 did not result in changes to the original carrying amount of the following financial instruments as compared to IAS 39.

	Measurement Category	
Financial Instrument	**IAS 39**	**IFRS 9**
Cash and cash equivalents	Fair value on a recurring basis	Amortised cost
Accounts receivable	Amortised cost	Amortised cost
Accounts payable and accrued liabilities	Amortised cost	Amortised cost
Long-term debt	Amortised cost	Amortised cost
Long-term liability		
Derivative contracts	Fair value	FVTPL

4. TRADE AND OTHER RECEIVABLES

Bengal's trade and other receivables are exposed to the risk of financial loss if a counterparty to a financial instrument fails to meet its contractual obligations. The Company's trade and other receivables include cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers.

The Company's trade and other receivables consist of:

($000s)	December 31, 2018	March 31, 2018
Due from joint venture partners	2,951	4,214
Other receivables	35	93
	2,986	4,307

In Australia, production is purchased by a buying group led by Santos Ltd., one of Australia's largest public oil and gas companies, and also the operator of Bengal's production. Bengal has a crude oil sales and purchase agreement with this buying group and has not experienced any collection problems to date.

Cash calls paid to Santos Ltd., Bengal's Australian joint venture partner, are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint venture receivables by approving significant spending by partners prior to expenditure and only paying the cash call shortly before the funds are to be spent.

The Company had no accounts considered past due at December 31, 2018 (March 31, 2018 - $nil). Past due is considered greater than 90 days outstanding.

Exposure to the carrying value of its financial instruments relates to the Company's commodity-based derivatives (Note 16) held by Westpac Banking Corporation, which carries a Standard & Poors credit rating of AA-. Management considers the credit risk of these instruments to be adequately mitigated by the credit rating of their holder; therefore, no allowance has been established.

5. EXPLORATION AND EVALUATION ASSETS ("E&E ASSETS")

Exploration and evaluation assets consist of the Company's exploration projects in Australia, which are pending the determination of proved or probable reserves. Costs primarily consist of acquisition costs, geological & geophysical work, seismic and drilling, and completion costs until the drilling of wells is complete and the results have been evaluated.

During Q1 fiscal 2019, the Company impaired $0.1 million pertaining to the carrying cost of its 10% interest in the offshore Timor Sea property, AC/RL 10. In Q2 fiscal 2019, the Company impaired $0.8 million related to an exploratory well drilled in the southwest of the Cuisinier field. Although oil was found, it was determined that the quantity was not sufficient to make the well commercial.

A summary of E&E Assets is shown in the table below:

($000s)	
Balance, April 1, 2017	20,529
Additions	1,768
Acquisition	509
Capitalized share-based compensation	7
Impairment	(12,167)
Exchange adjustments	(544)
Balance, March 31, 2018	10,102
Additions	870
Capitalized share-based compensation	4
Impairment	(885)
Exchange adjustments	(289)
Balance, end of period	9,802

A summary of E&E Assets is shown in the table below:

($000s)	
ATP 732P – Tookoonooka	5,380
ATP 752P	2,725
ATP 934 – Barrolka	1,852
Other(1)	145
Balance, beginning of period	10,102

($000s)	
ATP 732P – Tookoonooka	5,241
ATP 752P	2,680
ATP 934 – Barrolka	1,881
Other(1)	-
Balance, end of period	9,802

(1) Other includes capitalized G&A, share-based compensation and foreign exchange effects on these assets denominated in a foreign currency.

6. PROPERTY, PLANT AND EQUIPMENT

Petroleum and natural gas properties

($000s)	Petroleum and natural gas properties	Other assets	Total
Cost:			
Balance, April 1, 2017	47,875	344	48,219
Additions	1,234	-	1,234
Disposals	(4,316)	-	(4,316)
Capitalized share-based compensation	8	-	8
Change in decommissioning and restoration liability	167	-	167
Exchange adjustments	(732)	-	(732)
Balance, March 31, 2018	44,236	344	44,580
Additions	1,003	-	1,003
Capitalized share-based compensation	3	-	3
Exchange adjustments	(1,825)	-	(1,825)
Balance, end of period	43,417	344	43,761

($000s)	Petroleum and natural gas properties	Other assets	Total
Accumulated depletion, depreciation and impairment losses:			
Balance, April 1, 2017	19,386	287	19,673
Depletion and depreciation	2,026	14	2,040
Disposals	(4,316)	-	(4,316)
Exchange adjustments	76	-	76
Balance, March 31, 2018	17,172	301	17,473
Depletion and depreciation	1,076	8	1,084
Exchange adjustments	(1,050)	-	(1,050)
Balance, end of period	17,198	309	17,507

($000s)			
Net carrying amount:			
Beginning of period April 1, 2018	27,064	43	27,107
End of period December 31, 2018	26,219	35	26,254

The calculation of depletion for the quarter ended December 31, 2018 included $58.1 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2018 - $58.1 million).

7. TRADE AND OTHER PAYABLES

($000s)	December 31, 2018	March 31, 2018
Trade payables	508	702
Accrued liabilities and other payables	1,396	1,530
	1,904	2,232

8. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(1,984)
	12,386
Facility extension fees	(95)
Unrealized foreign exchange loss	2,683
Accretion	1,106
Balance, beginning of period Oct 1, 2018	16,080
Repayment	(176)
Unrealized foreign exchange gain	932
Accretion	80
Balance, end of period	16,916

($000s)	December 31, 2018	March 31, 2018
Current portion	-	1,934
Non-current portion	16,916	14,146

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$15.0 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 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%.

The Credit Facility is structured as a reserve-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 was 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 addition, the Company had agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement that requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve-based review by April 30, 2019. Pursuant to these terms, the Company repaid US$131,000 during Q3 fiscal 2019.

On November 19 2018, the Company and Westpac entered into a revised amendment agreement to the Credit Facility to defer all principal payments previously required under the March 5, 2018 amendment to February 15, 2020. This revised amendment now requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. All other terms and conditions previously provided under the March 5, 2018 amendment remain in effect. There is an interest rate change from 3.2% to 3.75% plus Libor effective January 1, 2019.

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 December 31, 2018.

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

(US $000s)	
Fiscal year 2019	-
Fiscal year 2020	12,369
	12,369

9. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2017	1,516
Change in estimate net of disposals	43
Accretion	37
Exchange adjustments	(40)
Balance, March 31, 2018	1,556
Accretion	30
Exchange adjustments	(45)
Balance, end of period	1,541

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation-adjusted undiscounted amount of cash flows required to settle its decommissioning and restoration costs at December 31, 2018 is approximately $2.1 million (March 31, 2018 – $2.2 million) which will be incurred between 2020 and 2046. An inflation factor of 1.3% (March 31, 2018 – 1.9%) and a risk-free discount rate of 2.7% (March 31, 2018 – 2.6%) have been applied to the decommissioning liability at December 31, 2018.

10. SHARE CAPITAL

($000s)	Number of common shares	Amount
Balance, April 1, 2017	68,177,796	94,151
Issued on exercise of rights offering	34,088,898	4,091
Share issue costs	-	(142)
Balance, March 31, 2018 and December 31, 2018	102,266,694	98,100

11. SHARE-BASED COMPENSATION – STOCK OPTIONS:

A summary of stock option activity is presented below:

	Options	Weighted average exercise price $
Balance, beginning of period April 1, 2018	4,602,500	0.52
Granted	250,000	0.11
Expired	(665,000)	0.65
Balance, end of period	4,187,500	0.13
Exercisable, end of period	321,096	0.26

The fair value of options granted during fiscal Q1 2019, were estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

Assumptions:	
Risk-free interest rate (%)	2.00
Expected life (years)	5
Expected volatility (%)(1)	95
Estimated forfeiture rate (%)	20
Weighted average fair value of options granted	$0.08
Weighted average share price on date of grant	$0.11

(1) Expected volatility is estimated by considering historic, average share price volatility.

The fair value of stock options granted during Q1 fiscal 2019 was approximately $16,000.

12. REVENUE

The nature of the Company's performance obligations, including roles as third parties and partners, are evaluated to determine if the Company acts as a principal. The Company recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if the Company acts in the capacity of an agent rather than as a principal. Currently the Company is primarily acting as agent and is recognizing revenue on a net basis.

Revenue from the sales of crude oil is based on the consideration specified in the Crude Oil Sales and Purchase Agreement ("COSPA agreement") with the joint venture operator. The Company recognizes revenue when it transfers control of the product to the joint venture operator, which is generally at the time the joint venture operator obtains legal title of the crude oil and when it is physically delivered to the pipeline at an estimated transaction price based on average US Brent price. The pricing of the oil barrels that are transferred is adjusted for quality and other factors specified in the COSPA agreement once the product is shipped to the end customer and lifted.

The transaction price as prescribed in the COSPA agreement is a variable price based on the benchmark US Brent commodity price index, and may be adjusted for quality, location, delivery method or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantity of crude oil transferred to the joint venture operator. The COSPA agreement has an initial term to March 31, 2022, whereby delivery takes place through the contract period. Revenues are typically collected 60 days following delivery to Port Bonython.

13. PER SHARE AMOUNTS

Income (loss) per share is calculated based on net loss and the weighted-average number of common shares outstanding.

($000s except per share amounts)	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Income (loss) for the period	883	206	(331)	255
Weighted average number of Common shares – basic and diluted	102,267	102,267	102,267	102,267
Basic and diluted income (loss) per share	0.01	0.00	0.00	0.00

For the three and nine months ended December 31, 2018, there were 4,187,500 (three and nine months ended December 31, 2017 – 4,602,500) options considered anti-dilutive.

14. FINANCE EXPENSE

($000s)	Three months ended December 31		Nine months ended December 31	
	2018	2017	2018	2017
Interest income	(1)	(2)	(9)	(12)
Accretion on decommissioning and restoration liability	10	9	30	28
Letter of credit charges	-	-	8	-
Interest on credit facility	248	246	740	718
	257	253	769	734

15. FOREIGN CURRENCY EXCHANGE RATE RISK

Bengal receives U.S. dollars for Australian oil sales and incurs expenditures in Australian and Canadian currencies. The Company may enter into derivative foreign currency contracts in order to manage foreign currency exchange rate risk, but has not done so to date.

The table below shows the Company's exposure to foreign currencies for its financial instruments at December 31, 2018:

($000s)	**CAD$**	**AUS$**	**US$**	**Total**
Cash and short-term deposits	399	35	3,595	4,029
Restricted cash	140	-	-	140
Trade and other receivables	15	19	2,952	2,986
Fair value of financial instruments	-	-	931	931
Trade and other payables	(236)	(1,668)	-	(1,904)
Credit facility	-	-	(16,916)	(16,916)

Exchange rates as at:	December 31 2018	March 31 2018
Number of CAD$ for 1 AUS$	0.96	0.99
Number of CAD$ for 1 US$	1.36	1.29

16. RISK MANAGEMENT ACTIVITIES

At December 31, 2018, the following derivative contracts were outstanding and recorded at estimated fair value:

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	21	46	67
Non-current fair value of financial instruments	-	-	-
	21	46	67

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	131	-	131
Non-current fair value of financial instruments	-	-	-
	131	-	131

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	128	-	128
Non-current fair value of financial instruments	-	-	-
	128	-	128

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	125	-	125
Non-current fair value of financial instruments	-	-	-
	125	-	125

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
July 1, 2019 – July 30, 2019	Oil - swap	5,000	75.03	75.03

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	141	-	141
Non-current fair value of financial instruments	-	-	-
	141	-	141

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	138	-	138
Non-current fair value of financial instruments	-	-	-
	138	-	138

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	136	-	136
Non-current fair value of financial instruments	-	-	-
	136	-	136

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
October 1, 2019 – December 31, 2019	Oil - swap	7,500	54.20	54.20
October 1, 2019 – December 31, 2019	Oil – put option	7,500	54.20	-

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(4)	69	65
Non-current fair value of financial instruments	-	-	-
	(4)	69	65

Total

(000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	816	115	931
Non-current fair value of financial instruments	-	-	-
	816	115	931

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US$61,000 (CAD$83,000) decrease in the fair value of financial instruments at December 31, 2018, while a US $1.00 decrease would result in an increase of approximately US$61,000 (CAD$83,000) in the fair value of the instruments.

17. SUPPLEMENTAL CASH FLOW INFORMATION

($000s)

Change in non-cash working capital items

	Three months ended December 31 2018	Three months ended December 31 2017	Nine months ended December 31 2018	Nine months ended December 31 2017
Trade and other receivables	984	(1,448)	1,321	(1,396)
Prepaid expenses and deposits	(22)	(15)	5	19
Trade and other payables	(807)	(103)	(328)	527
Effect of change in foreign exchange rates	49	9	(76)	(108)
	204	(1,557)	922	(958)
Attributable to:				
Operating	681	(837)	678	(443)
Investing	(250)	(720)	280	(456)
Financing	(227)	-	(36)	(59)
	204	(1,557)	922	(958)

The following represents the cash interest paid and received in each period:

($000s)

Cash interest paid and received

	Three months ended December 31 2018	Three months ended December 31 2017	Nine months ended December 31 2018	Nine months ended December 31 2017
Cash interest paid	476	183	730	537
Cash interest received	1	2	9	12

18. 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 Bengal Energy (Australia) Pty Ltd. of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of the first shipments of gas to market. The work program consists of 260 kilometers of 3D seismic and three wells.

Country and permit	Work program	Obligation period Ending	Estimated expenditure (net) (millions) Cdn $ (1)
Onshore Australia – ATP 934P	260 km^2 of 3D seismic and three wells with fracs and casing	February 2021	15.9
Onshore Australia – ATP 732	Geological and geophysical studies	March 2021	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at December 31, 2018 at an exchange rate of AUS$1.00 = CAD$0.9613.

At December 31, 2018, the Company had the following lease commitment for office space in Canada:

($000s) January 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
	776	155	311	310	-

19. SEGMENTED INFORMATION

As at December 31, 2018, the Company has three reportable operating segments being the Australian and Indian oil and gas operations, and corporate.

Revenue reported below represents revenue generated from external customers. There were no inter-segment sales in any of the reported periods.

The accounting policies of the reportable segments are the same as the group's accounting policies. Segment profit represents the profit earned by each segment without allocation of directors' salaries, finance costs and income tax expense. This is the measure reported to the chief operating decision maker for the purposes of resource allocation and assessment of segment performance.

($000s) For the nine months ended December 31, 2018	Australia	India	Corporate	Total
Revenue	8,544	-	-	8,544
Interest revenue	8	-	1	9
Interest expense	740	-	-	740
Depletion and depreciation	1,076	-	8	1,084
Impairment loss	885	-	-	885
Net income (loss)	742	(16)	(1,057)	(331)
Exploration and evaluation expenditures	870	-	-	870
Petroleum and natural gas property expenditures	1,003	-	-	1,003
($000s)				
As at December 31, 2018				
Exploration and evaluation assets	9,802	-	-	9,802
Petroleum and natural gas properties	26,219	-	-	26,219

($000s)

For the nine months ended December 31, 2017

	Australia	India	Corporate	Total
Revenue	7,927	-	-	7,927
Interest revenue	11	-	1	12
Interest expense	718	-	-	718
Depletion and depreciation	1,453	-	11	1,464
Net income (loss)	1,022	(3)	(764)	255
Exploration and evaluation expenditures	281	-	-	281
Petroleum and natural gas property expenditures	2,291	-	-	2,291

($000s)

As at December 31, 2017

Exploration and evaluation assets	20,028	-	-	20,028
Petroleum and natural gas properties	28,226	-	-	28,226

($000s)

For the three months ended December 31, 2018

	Australia	India	Corporate	Total
Revenue	2,014	-	-	2,014
Interest revenue	-	-	1	1
Interest expense	248	-	-	248
Depletion and depreciation	352	-	2	354
Impairment loss	(70)	-	-	(70)
Net income (loss)	1,163	-	(280)	883
Exploration and evaluation expenditures	(42)	-	-	(42)
Petroleum and natural gas property expenditures	340	-	-	340

($000s)

For the three months ended December 31, 2017

	Australia	India	Corporate	Total
Revenue	3,211	-	-	3,211
Interest revenue	1	-	1	2
Interest expense	246	-	-	246
Depletion and depreciation	464	-	4	468
Net income (loss)	521	-	(315)	206
Exploration and evaluation expenditures	51	-	-	51
Petroleum and natural gas property expenditures	291	-	-	291

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