Bengal Energy Ltd.

International exploration & production

Management's Discussion & Analysis

Three Months Ended
June 30, 2019 and 2018

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 the three months ended June 30, 2019.

This MD&A dated August 9, 2019 should be read in conjunction with the Company's consolidated financial statements and related notes for the quarter ended June 30, 2019. 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 Measurements", "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, 2019 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended June 30, 2019 may be referred to as "first quarter fiscal 2020", "Q1 FY 2020", "current quarter", and "the quarter". The comparative three months ended June 30, 2018, may be referred to as "first quarter fiscal 2019", "Q1 FY 2019", and "prior year's quarter".

FIRST QUARTER FISCAL 2020 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $2.0 million in the first quarter of fiscal 2020, which is 39% lower than the $3.2 million recorded in Q1 fiscal 2019. The lower sales revenue is due to a 22% decline in production quarter over quarter and an 8% lower $US Brent price.
- **Hedging** – The Company's Credit Facility requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. During Q1 fiscal 2020, the realized gain on financial instruments was $0.1 million while the unrealized loss on financial instruments was $0.08 million. Subsequent to June 30, 2019, hedges were placed on 50% of Q1 fiscal 2021 estimated production for April 2020 at US$59.49/bbl, May 2020 at US$59.27/bbl and June 2020 at US$59.08/bbl.
- **Cash from Operations –** Bengal generated cash from operations of $0.3 million during Q1 fiscal 2020 compared to $1.0 million of cash from operations in Q1 fiscal 2019. The primary reason for the decrease in dash from operations during fiscal 2020 as compared to fiscal 2019 was the lower sales revenue in Q1 fiscal 2020.
- **Net Loss** – Bengal reported a net loss of $0.8 million for the current quarter compared to a net loss of $0.5 million in the first quarter of fiscal 2019. The primary driver for the net loss for Q1 fiscal 2020 was the lower sales revenue.
- **Adjusted Net Income –** Bengal reported adjusted net loss of $0.5 million for the current quarter and adjusted net income of $0.4 million for Q1 fiscal 2019. Net income is adjusted for unrealized gain (loss) on financial instruments, the unrealized foreign exchange gain (loss) for the period and the non-cash impairment of non-current assets.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 22,688 bbls, which is a 22% decline from the 28,965 bbls produced in the first quarter of fiscal 2019. The current quarter production averaged 249 bbls per day compared to 318 bbls per day produced in the first quarter of fiscal 2019. Normal production declines are responsible for the quarter over quarter oil volume reductions.
- **Capital Expenditures** – Bengal incurred $1.3 million in capital expenditures during Q1 fiscal 2020. This investment went towards the completion of the five well drilling program, commenced in Q4 fiscal 2019 and the frac completion program of wells C15 and C21.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

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.

Under the State of Queensland Regulatory process, ATPs (Authority to Prospect) are granted by the State generally for a period of twelve years with one third of the original grant area expiring every four years. At the end of the final term of the ATP, an application can be made to continue a portion of the permit in the form of a PCA (Potential Commercial Area). PCAs 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. PLs are granted for up to a thirty-year term. Bengal now has two PLs in the Cuisinier field, PL 303 and PL 1028.

AUSTRALIA – Cooper Basin, Queensland

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

Completion and connection operations of the three successful wells drilled and the four wells fracture stimulated (two new wells and two existing wells) during the first half of calendar 2019 were completed during Q1 FY 2020. Before these new wells were brought into production, total pool production volumes were 820 barrels of oil per day ("bopd"), net 248 bopd (May 2019 average). The newly drilled and fracture stimulated wells were brought into production starting from the first week of June through the second week of July. Production has continued to gradually ramp up as the wells are optimized. Most recently available seven day total pool production volumes in mid-July averaged 1,374 bopd (net 417 bopd). Of note is the Cuisinier 29 well, which discovered a new oil pool in the DC-50 sand formation that lies below the target DC-70 zone in the Murta formation. The DC-50 sand formation has a gross thickness of 12.5 metres and exhibits virgin reservoir pressure. In addition, the well intersected approximately 2.2 metres of gross sand in the target zone DC-70 sand, which also shows virgin reservoir pressure. A development plan for the new DC-50 sand formation will be prepared with further drilling and evaluation expected in Q4 FY 2020 (calendar Q1 2020). First oil production from the newly drilled and fracture stimulated wells has commenced through the oil pipeline and production infrastructure linking the Cuisinier pool to the Port Bonython export facilities.

Further production results for the full calendar 2019 program will be announced in the coming weeks.

Planning and drilling location selection is underway for the next multi-well development and appraisal drilling campaign which is expected to commence in late calendar Q3 2020 (Q2 FY 2020).During the Q3 and Q4 fiscal 2019, 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 fracture stimulated 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 which commenced in early June was 322 bbls/d, for an 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. Ongoing evaluation of previously stimulated wells has assisted the Joint Venture in planning for its future drilling campaigns. These campaigns are designed to allow for fracture stimulations to occur upon completion as required. This is expected to result in operational efficiencies and cost savings in addition to potentially improved initial production rates on the stimulated wells.

The fiscal year 2019 drilling program consisting of four development wells and one appraisal well within PL 303 started in February 2019. Two of the four development wells, Cuisinier 29 and Cuisinier 30, were located on the northwest side of the Cuisinier pool close to production infrastructure and were designed to extend the producing area while potentially increasing the pool reserves area. The Cuisinier 29 well was successfully drilled, cased and suspended in late February and discovered a new oil pool in the DC-50 sand that lies below the target DC-70 zone. The DC-50 sand is approximately 12.5 metres thick and exhibits virgin reservoir pressure. In addition, the well intersected approximately 2.2 metres of gross sand in the target zone DC-70 sand, which also exhibits virgin reservoir pressure. The well has been cased and suspended as a potential oil producer.

The Cuisinier-27 and 28 development wells were located in the heart of the Cuisinier pool offsetting the planned waterflood pilot. Both of these wells met pre-drill expectations, encountering oil pay. These wells have been cased and suspended as Murta DC-70 oil wells. The fourth development well, Cuisinier-30, encountered 7.2 metres of Murta DC-70 sand; however the zone was low and water bearing. This well was therefore plugged and abandoned.

The Cuisinier-26 appraisal well was drilled in the southernmost part of PL 303 and was intended to extend the known producing sand fairway present in the core of the pool. The well encountered 0.8 metres of internally estimated net oil pay in the Murta DC-70 and was plugged and abandoned as uneconomic.

In Q1 FY 2020, the three successful wells were connected for production and an assessment of the productivity is being made. A development plan for the new DC-50 sand will be prepared based on initial production results. First oil sales from the new calendar 2019 wells are expected in early Q2 FY 2020. Results to date for the 2019 Cuisinier drilling campaign have been encouraging for further appraisal of the western extension of the Cuisinier oil field and particularly for the new zone in the Cuisinier 29 well. The program has shown a total of four oil reservoir zones that were encountered in three of the four development wells drilled. The new pool discovery in the DC-50 sand in the Cuisinier-29 well may provide further development drilling opportunities and pool expansion upside. Further results will be released upon program completion, which is anticipated to occur in early Q2 FY 2020.

The Joint Venture has also initiated the implementation of a pilot reservoir pressure maintenance scheme, which was planned to commence during Q2 FY 2020. Planning continues however regulatory delays now indicate start up early in calendar 2020 (Q4 FY 2020). 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 variable 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.

Wompi Block (Controlling permit ATP 752) (38.08% WI)

The Joint Venture is planning to conduct an extended production test on the Nubba well during Q4 of calendar 2019 (Q3 FY 2020) with plans to pipeline connect the well for production through a new natural gas pipeline subject to commercial flow rates and gas reserves being achieved.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned gas exploration block. Bengal's completion of seismic amplitude inversion studies have highlighted the most favourable areas of the permit allowing for additional detailed geophysical work. The reprocessing of select 2D seismic lines will be valuable in selection of future drilling locations and locating the area of potential 3D seismic acquisition in fiscal year 2021. In addition to inversion, the Company has also embarked on depth image processing to help mitigate the velocity impact of near surface velocity changes, known to affect the quality of the time to the depth conversion. This work is expected to be completed by the end of August 2019 and will further advance the de-risking of previously high graded prospect areas.

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 this permit.

OPERATING SUMMARY

($000s except per share, %, volumes and netback amounts)	Three months ended June 30	
	2019	2018
Oil revenue	$ 1,962	$ 3,215
Operating netback(1)	$ 1,112	$ 1,613
Cash from operations	$ 316	$ 1,019
Funds (used in) from operations(2)	$ (13)	$ 875
Per share ($) (basic and diluted)	$ 0.00	$ 0.01
Net loss	$ (750)	$ (486)
Per share ($) (basic and diluted)	$ (0.01)	$ (0.00)
Adjusted net (loss) income(3)	$ (485)	$ 427
Per share ($) (basic and diluted)	$ 0.00	$ 0.00
Capital expenditures	$ 1,280	$ 301
Oil volumes (bbl/d)	249	318
Operating Netback(1)($/bbl)	$ 49.01	$ 55.69

(1) Operating netback is a non-IFRS measure and includes realized gain (loss) on financial instruments. Operating 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 on page 7.
(2) Funds from operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. 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. A reconciliation of the measures can be found in the table on page 18.
(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.
(4) The above non-IFRS measures do not have any standardized meaning under 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 June 30	
	2019	2018
Oil production (bbls/d)	249	318
Oil production (bbls)	22,688	28,965

Revenue/Pricing

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

		Three months ended June 30 2019	2018
	Oil lifting		
	Volume (000s bbls)	24.3	36.9
	Weighted average price ($US/bbl)	70.00	76.40
	Sales ($US000's)	1,701	2,819
A.	Sales ($000's)	2,296	3,806
	Pipeline oil		
	Volume (000s bbls), change	(1.6)	(8.0)
	Price ($US/bbl), change	(8.47)	6.04
	Net sales ($US000's)	(251)	(446)
B.	Net sales ($000's)	(334)	(591)
A.+B.	Total oil sales ($000s)	1,962	3,215

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 and waiting to be sold. Lifting occurs when the oil is moved from the port to the ship.

Realized crude oil price during Q1 fiscal 2020 was significantly impacted by the decline in US Brent as compared to Q1 fiscal 2019. The realized weighted average price of oil lifting sales was US$ 70.00/bbl and US$76.40/bbl for Q1 FY 2020 and 2019 respectively. When combined with lower oil lifting volumes in Q1 fiscal 2020 of 24.3K bbls as compared to 36.9K bbls in Q1 fiscal 2019, oil lifting sales were lower at $2.3 million for the current quarter as compared to $3.8 million for Q1 fiscal 2019. During the current quarter, the value of the pipeline oil declined by $0.3 million due to an overall reduction in oil volume of 1.6K bbls (16,412 bbls at the beginning of the quarter down to 14,822 at the end of the quarter) and a reduction in overall price valuation of $8.47 per bbl. When oil lifting sales are adjusted for the change in value of the pipeline oil for the current quarter of $(0.3) million, Bengal's total oil sales are $2.0 million for the current quarter as compared to $3.2 million for Q1 fiscal 2019.

The following table outlines average benchmark prices:

	Three months ended June 30 2019	2018
Brent oil ($/bbl)	92.23	96.15
Brent oil (US$/bbl)	68.83	74.50
Number of CAD$ for 1 AUS$	0.94	0.98
Number of CAD$ for 1 US$	1.34	1.29

($000s)

Operating netbacks

	Three months ended June 30	
	2019	**2018**
Oil sales	1,962	3,215
Realized gain (loss) on financial instruments	94	(415)
Royalties	101	118
Operating expenses	843	1,069
Operating netback	1,112	1,613

($/bbl)

Oil sales	86.48	111.00
Realized gain (loss) on financial instruments	4.14	(14.33)
Royalties	4.45	4.07
Operating expenses	37.16	36.91
Operating netback	49.01	55.69

Operating netbacks in Q1 fiscal 2020 were $1.1 million or $49.01/bbl compared to Q1 fiscal 2019 at $1.6 million or $55.69/bbl. The primary reason for the lower operating netbacks during the current quarter compared to Q1 fiscal 2019 was the realization of a lower dollar per barrel on oil sales. During the current quarter, Bengal realized an average of $86.48/bbl as compared to $111/bbl on oil sales revenue for Q1 fiscal 2019. Operating expenses for the current quarter were $37.16/bbl as compared to $36.91/bbl for Q1 fiscal 2019. Bengal had a realized gain on financial instruments of $0.1 million due to the approximate US$73/bbl hedges throughout the three months ended Q1 fiscal 2020. Royalty rates came in at 5% of oil sales for Q1 fiscal 2020 or $4.45 per bbl as compared to 4% of oil sales or $4.07 per bbl for Q1 fiscal 2019. The higher royalty expense per barrel is due to a small adjustment by the operator in the current quarterly calculation

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).

As at June 30, 2019, the Company has the following derivative contracts:

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	61	-	61
Non-current fair value of financial instruments	-	-	-
	61	-	61

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	62	-	62
Non-current fair value of financial instruments	-	-	-
	62	-	62

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	61	-	61
Non-current fair value of financial instruments	-	-	-
	61	-	61

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	(100)	14	(86)
Non-current fair value of financial instruments	-	-	-
	(100)	14	(86)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
January 1, 2020 – March 31, 2020	Oil - swap	15,000	63.74	63.74

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

Total

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	83	14	97
Non-current fair value of financial instruments	-	-	-
	83	14	97

Subsequent to June 30, 2019, hedges were placed on 50% of Q1 fiscal 2021 estimated production for April 2020 at US$59.49/bbl, May 2020 at US$59.27/bbl and June 2020 at US$59.08/bbl.

The fair value of the financial contracts outstanding as at June 30, 2019 is $0.1 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period, having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the three months ended June 30, 2019, the derivative commodity contracts resulted in a realized gain of $0.1 million (June 30, 2018 – loss of $0.4 million) and an unrealized loss of $0.1 million (June 30, 2018 – loss of $0.2 million).

Royalties

Royalties

	Three months ended June 30	
	2019	2018
Royalty expense ($000s)	101	118
$/bbl	4.45	4.07
% of revenue	5	4

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

Royalty rates came in at 5% of oil sales for Q1 fiscal 2020 or $4.45 per bbl as compared to 4% of oil sales or $4.07 per bbl for Q1 fiscal 2019. The higher royalty expense per barrel is due to a small adjustment by the operator in the current quarterly calculation.

Operating Expenses

($000s) Operating expenses	Three months ended June 30 2019	 2018
Production	152	183
Transportation	691	886
	843	1,069
Production - $/bbl	6.70	6.32
Transportation - $/bbl	30.46	30.59
	37.16	36.91

Total operating expense during the first quarter fiscal 2020 was $0.8 million, 21% lower than the first quarter of fiscal 2019. The lower operating expense was due to lower production and pipeline throughput. For Q1 fiscal 2020, the operating expense per barrel was $37.16/bbl as compared to $36.91/bbl for Q1 fiscal 2019. The slight increase in operating expense per barrel is due to additional maintenance and trucking charges during the current quarter.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended June 30 2019	 2018
Total G&A	969	778
Capitalized Staff G&A	(18)	(45)
Capitalized Contractors G&A	(20)	(65)
Net G&A	931	668

The increase in Total G&A spending is due to additional one-time third party contractors assisting the Company in evaluating new business opportunities during the current quarter. Net G&A expenses in the first quarter fiscal 2020 were $0.9 million as compared to $0.7 million for the first quarter fiscal 2019. The 39% increase or $263K in net G&A expense for the first quarter fiscal 2020 is due to a lower amount of activity by staff and contractors that was charged to capital projects.

Share-based Compensation ("SBC")

($000s) SBC	Three months ended June 30 2019	2018
Expensed share-based compensation	11	30
Capitalized share-based compensation	1	4
	12	34

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.

Depletion and Depreciation (DD&A)

($000s) DD&A	Three months ended June 30 2019	2018
Petroleum and natural gas properties	340	378
Other assets	2	3
Right-of-use assets	12	-
	354	381
Petroleum and natural gas properties - $/bbl	14.99	13.05

Production in Q1 fiscal 2020 was 22,688 bbls compared with 28,965 bbls in Q1 fiscal 2019. The lower production in Q1 fiscal 2020 when compared to Q1 fiscal 2019 resulted in lower depletion expense, partially offset by the increase in reserves in fiscal 2019.

Impairment Expense

($000s) Impairment expense	Three months ended June 30 2019	2018
Exploration and evaluation assets	10	145
Petroleum and natural gas properties	10	-
	20	145

During Q1 fiscal 2020, the Company took an impairment charge of $0.02 million due to charges passed through by the Joint Venture operator on three wells previously deemed impaired (the Chookola well, C26 and C30).

Finance Expense

($000s) Finance expense	Three months ended June 30 2019	2018
Interest income	(1)	(7)
Accretion expense on decommissioning and restoration liability	9	10
Letter of credit charges	-	8
Interest on lease liability	4	-
Interest on Credit Facility	301	243
	313	254

Interest on the Credit Facility is calculated as LIBOR plus a margin of 3.75%, compared with LIBOR plus 3.25% during 2018.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended June 30 2019	2018
Geological and geophysical	60	137
Drilling	134	83
Completions	1,086	81
	1,280	301
Exploration and evaluation expenditures	10	160
Development and production expenditures	1,270	141
	1,280	301

The development and production expenditure of $1.3 million in Q1 fiscal 2020 relates to the continued five well 2019 drilling program.

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 25, 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 was an interest rate change from LIBOR plus 3.2% to 3.75% effective January 1, 2019.

On May 29, 2019, the Company and Westpac entered into an amendment to the November 19, 2018 agreement that has all principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment have transferred directly to the May 29, 2019 amendment.

Management is in discussion with the lender to further amend the current repayment terms and expects that an extension will be granted. 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.

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 June 30, 2019.

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

(US$000s)	
Credit Facility	
Fiscal year 2020	12,369

SHARE CAPITAL

Trading history		
	Three months ended June 30	
	2019	**2018**
High ($)	0.13	0.18
Low ($)	0.06	0.11
Close ($)	0.10	0.16
Volume (000s)	786	2,760
Shares outstanding (000s)	102,267	102,267
Weighted average shares outstanding (000s) - basic and diluted	102,267	102,267

At August 9, 2019, there were 102,266,694 common shares issued and outstanding, together with 3,638,875 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 trade and other payables, lease liability and credit facility, amounting to $18.4 million at June 30, 2019 (March 31, 2019 - $19.1 million).

At June 30, 2019, the Company had a working capital deficiency of $14.0 million, including cash and short-term deposits of $1.4 million and restricted cash of $0.1 million, compared to a working capital deficiency of $12.7 million at June 30, 2018 and working capital of $12.7 million at March 31, 2019. The working capital deficit of $14.0 million is primarily a result of the reclassification of the bank debt of $16.5 million to current from long term. The Company does not anticipate any difficulty in meeting its current obligations as the Company has generated positive working capital and is forecasted to continue to generate positive working capital. The Company has no available undrawn debt capacity under its Westpac Credit Facility.

The Company has significant spending commitments to be incurred by February 2021 on ATP 934 and has its US$12.4 million Credit Facility that matures in April 2020. Management anticipates that future and ongoing discussions with Westpac will defer the current repayment date and that operating and capital requirements 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. Should Westpac not further defer principal payments and the Company be unsuccessful in obtaining additional funding, there will be an adverse impact to the Company's liquidity.

The majority of the Company's oil sales are benchmarked on US$ Brent prices, which averaged US$68.83/bbl for the three months ended June 30, 2019. 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 lower 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 practical and appropriate. The Company intends to 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 and development activities through fiscal 2020 and beyond.

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 FY 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 km^2 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. See Liquidity Risk and Capital Resources above.

At June 30, 2019, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and three wells with fracs and casing	February 2021	12.9
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 June 30, 2019 at an exchange rate of AUS$1.00 = CAD$ 0.9180.

At June 30, 2019, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2019 to November 2023	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Office lease	698	155	311	232	-
Decommissioning and restoration	1,926	-	547	-	1,378
	2,624	155	858	232	1,378

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	**June 30 2019 Q1 2020**	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2019	Mar 31 2018 Q4 2018	Dec 31 2017 Q3 2018	Sep 30 2017 Q2 2018
Oil sales	1,962	2,667	2,014	3,315	3,215	2,783	3,211	2,410
Cash from operations	316	635	434	603	1,019	858	431	648
Funds from (used in) operations[1]	(13)	842	(247)	750	875	525	1,268	110
Per share – basic and diluted ($)	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.00
Net (loss) income	(750)	(2,144)	883	(728)	(486)	(12,526)	206	(500)
Per share – basic and diluted ($)	(0.01)	(0.02)	0.01	(0.01)	0.00	(0.12)	0.00	0.00
Capital expenditures	1,280	2,473	298	1,274	301	939	342	1,527
Working capital (deficiency)	(13,964)	(12,740)	6,331	(3,353)	(2,915)	3,385	(637)	2,107
Total assets	40,373	42,489	44,291	43,547	44,867	45,714	56,932	56,032
Shares outstanding (000s)	102,267	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls)	249	281	300	292	318	334	354	383
Netback[1] ($/bbl)	49.01	76.82	22.54	59.58	55.69	42.66	63.13	27.21

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

Oil sales and production over the last eight quarters peaked during the second quarter of fiscal 2018 (calendar Q3 2017) as all wells from the Company's 2014 and 2016 drilling campaign were on stream. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since the peak in the second quarter of fiscal 2018. A significant decline in $US Brent prices during Q3 fiscal 2019 was responsible for the low oil sales and funds from operations. The Company began a five well drilling program in Q4 fiscal 2019 that will be completed by the end of Q1 fiscal 2020.

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, 2019 due to the material weaknesses noted below.

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

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

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

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

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board 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 2019 annual Management's Discussion and Analysis dated June 20, 2019.

NEW ACCOUNTING STANDARDS

Effective April 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in net income (loss) and comprehensive income (loss) in the consolidated statements of comprehensive income (loss). IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $249,933 increase to right-of-use assets (Note 6), with a corresponding increase to lease liability (Note 9). There was an adjustment of $ 31,232 for lease incentives previously received.

On adoption of IFRS 16, the Company's lease liability related to contracts classified as leases are measured at the discounted present value of the remaining minimum lease payments, excluding short-term and low-value leases. The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations. The weighted average incremental borrowing rate used to determine the lease liability at adoption was approximately 6.0%. The right-of-use asset and lease liability recognized relate to the Company's head office lease in Calgary.

Upon the adoption of IFRS 16, the Company adopted the following significant accounting policy effective April 1, 2019:

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease liability is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received, retirement costs and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term. Interest expense is recognized on the lease liability using the effective interest rate method and payments are applied against the lease liability.

Key areas where management has made judgments, estimates and assumptions related to the application of IFRS 16 include:

- The incremental borrowing rate is based on judgments including economic environment, term, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease liability and the resulting interest expense and depreciation expense, may differ due to changes in the market conditions and lease term.
- Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netbacks, netbacks per share, funds from operations, funds from operations per share, adjusted net income and adjusted net income per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Netback equals total revenue (including realized gain (loss) 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 a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. 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 income 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 income equals net income (loss) less unrealized gain (losses) on foreign exchange and unrealized gain (losses) on financial instruments plus non-cash impairment of non-current assets. Adjusted net income 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 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 June 30**	
	2019	**2018**
Cash from operating activities	316	1,019
Changes in non-cash working capital	(329)	(144)
Funds (used in) from operations	(13)	875

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

($000s)	**Three months ended June 30**	
	2019	**2018**
Net loss	(750)	(486)
Unrealized loss on financial instruments	75	180
Unrealized foreign exchange loss	170	588
Non-cash impairment of non-current assets	20	145
Adjusted net (loss) income	(485)	427

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
bopd		barrels of oil per day
FY	-	fiscal year
K	-	thousand
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
WI	-	working interest

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 July 2, 2019 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.

An investment in the shares of the Company should be considered speculative due to the nature of the Company's involvement in the exploration for and the acquisition, development and production of oil and natural gas in foreign countries, and its current stage of development. An investor should consider carefully the risk factors set out in the annual information form and consider all other information contained herein and in the Company's other public filings before making an investment decision. Additional risks and uncertainties not currently known to the management of the Company may also have an adverse effect on Bengal's business and the information set out in the annual information form does not purport to be an exhaustive summary of the risks affecting Bengal.

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.*
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;*
- *Bengal's drilling program and waterflood pilot;*
- *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 timing of first oil sales from the new 2019 wells;*
- *The expected timing of the multi-well development and appraisal drilling campaign on the Barta Block PL 303;*
- *The expected operational efficiencies and cost savings as well as potentially improved initial production rates in relation to the fracture stimulation campaign on four wells on ATP 752;*
- *The potential of further development drilling opportunities and pool expansion upside in the DC-50 sand in the Cuisinier 29 well;*
- *The timing of further results on the 2019 drilling program completion;*
- *The expected timing of the commencement of a pilot pressure maintenance scheme and the potential positive performance response of up to four offsetting producing wells in the Cuisinier field;*
- *Expected plans to conduct production tests on the Nubba Well;*
- *The timing of the completion of the depth image processing completion on ATP 934;*
- *Approximations of amounts that would be paid to settle financial contracts;*
- *Expected extensions and amendments to the Credit Facility and the results of discussions with Westpac;*
- *The possibility of third parties farming in on ATP 934 Barrolka;*
- *The possibility of additional reprocessing and acquisition of 2D and 3D seismic on ATP 934;*
- *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 financing;*
- *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 2020 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;*
- *Changes in the demand for or supply of Bengal's products;*
- *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).

Disclosure of Oil and Gas Information

Unless otherwise specified, reserves data set forth in this document is based upon an independent reserve assessment and evaluation prepared by GLJ with an effective date of March 31, 2019 (the "GLJ Report"). The GLJ Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and the reserve definitions contained in National Instrument 51-101 – Standards of Disclosure For Oil and Gas Activities ("NI 51-101").

This document includes estimates of thickness net pay, which estimates may be considered to be anticipated results under NI 51-101. The estimates were prepared internally. References to thickness of "net oil pay" or of a formation where evidence of hydrocarbons has been encountered is not necessarily an indicator that hydrocarbons will be recoverable in commercial quantities or in any estimated volume. Bengal may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves. Well test results should be considered as preliminary and not necessarily indicative of long-term performance or of ultimate recovery. Well log interpretations indicating oil and gas accumulations are not necessarily indicative of future production or ultimate recovery. If it is indicated that a pressure transient analysis or well-test interpretation has not been carried out, any data disclosed in that respect should be considered preliminary until such analysis has been completed.

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
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG

Interim Consolidated Financial Statements

(Unaudited)

Three Months Ended

June 30, 2019 and 2018

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(unaudited)

As at	Notes	June 30 2019	March 31 2019
Assets			
Current assets:			
Cash and cash equivalents		$ 1,436	$ 2,891
Restricted cash		140	140
Trade and other receivables	4	2,399	2,972
Prepaid expenses and deposits		140	136
Fair value of financial instruments	16	97	177
		4,212	6,316
Exploration and evaluation assets	5	9,410	9,711
Property, plant and equipment	6	26,751	26,462
Total assets		$ 40,373	$ 42,489
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	7	$ 1,955	$ 2,574
Current portion of credit facility	8	16,175	16,482
Current portion of lease liability	9	46	-
		18,176	19,056
Decommissioning and restoration liability	10	1,926	1,977
Lease liability	9	193	-
		20,295	21,033
Shareholders' equity:			
Share capital	11	98,100	98,100
Contributed surplus		7,844	7,832
Accumulated other comprehensive loss		(644)	(4)
Deficit		(85,222)	(84,472)
		20,078	21,456
Total liabilities and shareholders' equity		$ 40,373	$ 42,489

Commitments (Note 18)

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

For the three months ended June 30	Notes		**2019**		**2018**
Revenue					
Oil sales	13	$	1,962	$	3,215
Royalties			(101)		(118)
			1,861		3,097
Realized gain (loss) on financial instruments	16		94		(415)
Unrealized loss on financial Instruments	16		(75)		(180)
			1,880		2,502
Expenses					
General and administrative			931		668
Operating			843		1,069
Depletion and depreciation	6		354		381
Impairment	5,6		20		145
Share-based compensation			11		30
Foreign exchange loss			158		441
			2,317		2,734
Other expense					
Finance expense	15		313		254
Net loss			(750)		(486)
Exchange differences on translation of foreign operations			(640)		(444)
Comprehensive loss		$	(1,390)	$	(930)
Loss per share - basic & diluted	14	$	(0.01)	$	(0.00)
Weighted average shares outstanding (000s) – basic and diluted	14		102,267		102,267

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)

(unaudited)

For the three months ended June 30	2019	2018
Share capital		
Balance at beginning and end of period	$ 98,100	$ 98,100
Contributed surplus		
Balance at beginning of period	7,832	7,755
Share-based compensation – expensed	11	30
Share-based compensation – capitalized	1	4
Balance at end of period	7,844	7,789
Accumulated other comprehensive (loss) income		
Balance at beginning of period	(4)	1,034
Exchange differences translation of foreign operations	(640)	(444)
Balance at end of period	(644)	590
Deficit		
Balance at beginning of period	(84,472)	(81,997)
Net loss	(750)	(486)
Balance at end of period	(85,222)	(82,483)
Total shareholders' equity	$ 20,078	$ 23,996

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

(unaudited)

For the three months ended June 30	Notes	2019	2018
Operating activities:			
Net loss		$ (750)	$ (486)
Add (deduct) non-cash items			
Depletion and depreciation		354	381
Accretion on decommissioning and restoration liability		9	10
Accretion on credit facility		63	27
Share-based compensation		11	30
Interest on lease liability		4	-
Lease incentive		31	-
Impairment		20	145
Unrealized loss on financial instruments		75	180
Unrealized foreign exchange loss		170	588
Funds (used in) from operations		(13)	875
Change in non-cash working capital	17	329	144
Net cash from operating activities		316	1,019
Investing activities:			
Exploration and evaluation expenditures	5	(10)	(160)
Petroleum and natural gas property expenditures	6	(1,270)	(141)
Change in non-cash working capital	17	(400)	48
Net cash used in investing activities		(1,680)	(253)
Financing activities:			
Lease payments		(15)	-
Facility extension fees	8	(20)	-
Change in non-cash working capital	17	-	(33)
Net cash used in financing activities		(35)	(33)
Net (decrease) increase in cash and cash equivalents		(1,399)	733
Cash and cash equivalents, beginning of period		2,891	3,904
Impact of foreign exchange on cash and cash equivalents		(56)	(67)
Cash and cash equivalents, end of period		$ 1,436	$ 4,570

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 its wholly-owned subsidiaries including Bengal Energy Australia (Pty) Ltd. and Bengal Energy International Inc., which are incorporated in Australia and Canada respectively. 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 interim consolidated 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, 2019 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, 2019.

The interim consolidated financial statements were approved and authorized for issuance by the Board of Directors on August 9, 2019.

The Company's presentation currency is Canadian dollars. The functional currency of the Canadian parent entity is Canadian dollars; the functional currency of the Australian subsidiary is Australian dollars.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies used are consistent with those of the previous financial year as described in Note 22 of the Company's consolidated financial statements for the year ended March 31, 2019, except for the following adoption of new accounting standards effective April 1, 2019.

Adoption of IFRS 16, Leases

Effective April 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in net income (loss) and comprehensive income (loss) in the consolidated statements of comprehensive income (loss). IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $249,933 increase to right-of-use assets (Note 6), with a corresponding increase to lease liability (Note 9). There was an adjustment of $ 31,232 for lease incentives previously received.

On adoption of IFRS 16, the Company's lease liability related to contracts classified as leases are measured at the discounted present value of the remaining minimum lease payments, excluding short-term and low-value leases. The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations. The weighted average incremental borrowing rate used to determine the lease liability at adoption was approximately 6.0%. The right-of-use asset and lease liability recognized relate to the Company's head office lease in Calgary.

Upon the adoption of IFRS 16, the Company adopted the following significant accounting policy effective April 1, 2019:

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease liability is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received, retirement costs and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term. Interest expense is recognized on the lease liability using the effective interest rate method and payments are applied against the lease liability.

Key areas where management has made judgments, estimates and assumptions related to the application of IFRS 16 include:

- The incremental borrowing rate is based on judgments including economic environment, term, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease liability and the resulting interest expense and depreciation expense, may differ due to changes in the market conditions and lease term.
- Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

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)	**June 30, 2019**	**March 31, 2019**
Due from joint venture partners	2,343	2,928
Other receivables	56	44
	2,399	2,972

In Australia, production is purchased by a buying group led by Santos Ltd., 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 interest partner, are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint interest 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 June 30, 2019 (March 31, 2019 - $nil). Past due is considered greater than 90 days outstanding.

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")

($000s)	
Balance, April 1, 2018	10,102
Additions	930
Acquisition	-
Capitalized share-based compensation	4
Impairment	(894)
Exchange adjustments	(431)
Balance, March 31, 2019	9,711
Additions	10
Capitalized share-based compensation	-
Impairment	(10)
Exchange adjustments	(301)
Balance, June 30, 2019	9,410

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

($000s)	
ATP 732P – Tookoonooka	5,165
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,641
ATP 934 – Barrolka	1,905
Balance, March 31, 2019	9,711

($000s)	
ATP 732P – Tookoonooka	5,005
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,559
ATP 934 – Barrolka	1,846
Balance, June 30, 2019	9,410

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.

6. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, April 1, 2018	44,236	344	-	44,580
Additions	3,416	-	-	3,416
Capitalized share-based compensation	4	-	-	4
Change in decommissioning and restoration liability	448	-	-	448
Exchange adjustments	(2,737)	-	-	(2,737)
Balance, March 31, 2019	45,367	344	-	45,711
Additions	1,270	-	-	1,270
Right-of-use addition (non-cash)	-	-	219	219
Capitalized share-based compensation	1	-	-	1
Exchange adjustments	(2,027)	-	-	(2,027)
Balance, June 30, 2019	44,611	344	219	45,174

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment losses:				
Balance, April 30, 2018	17,172	301	-	17,473
Depletion and depreciation	1,446	11	-	1,457
Impairment	1,897	-	-	1,897
Exchange adjustments	(1,578)	-	-	(1,578)
Balance, March 31, 2019	18,937	312	-	19,249
Depletion and depreciation	340	2	12	354
Impairment	10	-	-	10
Exchange adjustments	(1,190)	-	-	(1,190)
Balance, June 30, 2019	18,097	314	12	18,423
($000s)				
Net carrying amount:				
At June 30, 2019	26,514	30	207	26,751
At March 31, 2019	26,430	32	-	26,462

The Company recorded an impairment charge of $1.9 million during Q4 fiscal 2019 due to uneconomic drilling results.

The calculation of depletion for the three months ended June 30, 2019 included $61.0 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2019 - $60.9 million).

During the three months ended June 30, 2019, the Company capitalized $38,000 of general and administrative expense (2018 - $110,000).

The Company recognized a right-of-use asset and the corresponding lease liability (Note 9) related to the Company's head office lease in Calgary. The right-of-use asset addition of $219,000 was net of a lease incentive of $31,000.

7. TRADE AND OTHER PAYABLES

($000s)	June 30, 2019	March 31, 2019
Trade payables	926	1,525
Accrued liabilities and other payables	1,029	1,049
	1,955	2,574

8. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(2,160)
	12,210
Facility extension fees	(227)
Unrealized foreign exchange loss	3,264
Accretion	1,235
Balance, March 31, 2019	16,482
Unrealized foreign exchange loss	(350)
Facility extension fees	(20)
Accretion	63
Balance, June 30, 2019	16,175

($000s)	June 30, 2019	March 31, 2019
Current portion	16,175	16,482
Non-current portion	-	-

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 25, 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 was an interest rate change from LIBOR plus 3.2% to 3.75% effective January 1, 2019. Given the repayment date of February 15, 2020, the debt has been classified as current as at March 31, 2019.

On May 29, 2019, the Company and Westpac entered into an amendment to the November 19, 2018 agreement that has the all principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment will transfer directly to the May 29, 2019 amendment.

Management is in discussion with the lender to further amend the current repayment terms and expects that an extension will be granted. 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.

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 June 30, 2019.

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

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

9. LEASE LIABILITY

The Company incurs lease payments related to the Company's head office lease in Calgary.

($000s)	
Balance, March 31, 2019	-
Lease liability for right-of-use assets	250
Interest	4
Payments	(15)
Balance, June 30, 2019	239
Current portion of lease liability	(46)
Non-current portion of lease liability	193

10. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2018	1,556
Change in estimate	168
Additions	280
Accretion	39
Exchange adjustments	(66)
Balance, March 31, 2019	1,977
Accretion	9
Exchange adjustments	(60)
Balance, June 30, 2019	1,926

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 June 30, 2019 is approximately $2.5 million (March 31, 2019 – $2.5 million) which will be incurred between 2022 and 2048. An inflation factor of 1.78% and a risk-free discount rate of 1.79% have been applied to the decommissioning liability at June 30, 2019.

11. SHARE CAPITAL

Authorized:

Unlimited number of common shares with no par value.

Unlimited number of preferred shares, of which none have been issued.

Issued:

The following provides a continuity of share capital:

($000s)	**Number of common shares**	**Amount**
Balance, April 1, 2018	68,177,796	94,151
Issued on exercise of rights offering	34,088,898	4,091
Share issue costs	-	(142)
Balance at March 31, 2019 and June 30, 2019	102,266,694	98,100

12. SHARE-BASED COMPENSATION

The Company has a share option plan for directors, officers and employees of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of up to five years and vest one-third immediately and one-third on each of the next two anniversary dates. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

Effective with the option grant on December 21, 2012, vesting occurs one third after the first year and one third on each of the two subsequent anniversaries. Effective with the option grant of July 30, 2015, performance criteria were introduced, which allow for the vesting of stock options contingent on meeting pre-established targets based on internal and external metrics.

Effective with the option grant on April 9, 2018, the exercise price of each option equals the weighted average market share price of the previous five days.

The Company accounts for its share-based compensation plan using the fair value method. Under this method, each grant results in three instalments. The fair value of the first instalment is charged to profit or loss immediately. The remaining two instalments are charged to profit or loss over their respective vesting period of one and two years respectively. For options that vest one-third each year on the first year anniversary, the fair value of the options are charged to profit and loss over the three year vesting period. Stock options granted under the plan can be exercised on a cashless basis, whereby the employee receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the employee so elects.

A summary of stock option activity is presented below:

	Options	Weighted average exercise price
		$
Balance, March 31, 2019	4,102,500	0.12
Forfeited	(463,625)	0.12
Balance, June 30, 2019	3,638,875	0.12
Exercisable, June 30, 2019	897,208	0.12

13. REVENUE

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 and 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.

14. 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 June 30	**2019**	**2018**
Net loss for the period	(750)	(486)
Weighted average number of common shares – basic and diluted	102,267	102,267
Basic and diluted loss per share	$ (0.01)	$ (0.00)

For the three months ended June 30, 2019, there were 3,005,263 (2018 – 4,852,500) options considered anti-dilutive.

15. FINANCE EXPENSE

($000s)		
For the three months ended June 30	**2019**	**2018**
Interest income	(1)	(7)
Accretion on decommissioning and restoration liability	9	10
Letter of credit charges	-	8
Interest on lease liability	4	-
Interest on credit facility	301	243
	313	254

16. FINANCIAL RISK MANAGEMENT

Liquidity Risk

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 trade and other payables, lease liability and credit facility, amounting to $18.4 million at June 30, 2019 (March 31, 2019 - $19.1 million).

At June 30, 2019, the Company had a working capital deficiency of $14.0 million, including cash and short-term deposits of $1.4 million and restricted cash of $0.1 million, compared to a working capital deficiency of $12.7 million at June 30, 2018 and working capital of $12.7 million at March 31, 2019. The working capital deficit of $14.0 million is primarily a result of the reclassification of the bank debt of $16.5 million to current from long term. The Company has no available undrawn debt capacity under its Westpac Credit Facility.

The current challenging economic climate may lead to adverse changes in cash flow, working capital levels or debt balances, which may also have a direct impact on the Company's results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

Foreign Currency 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 June 30, 2019:

($000s)	CAD$	AUS$	US$	Total
Cash and short-term deposits	190	76	1,170	1,436
Restricted cash	140	-	-	140
Trade and other receivables	24	94	2,281	2,399
Fair value of financial instruments	-	-	97	97
Trade and other payables	(237)	(1,710)	(8)	(1,955)
Credit facility	-	-	(16,175)	(16,175)
Lease liability	(239)	-	-	(239)
	(122)	(1,540)	(12,635)	(14,297)

Exchange rates as at:	June 30 2019	March 31 2019
Number of CAD$ for 1 AUS$	0.92	0.95
Number of CAD$ for 1 US$	1.31	1.34

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of a change in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. Australian oil prices are based on the US Brent reference price, which currently trades at a premium to WTI.

At June 30, 2019, 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
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	61	-	61
Non-current fair value of financial instruments	-	-	-
	61	-	61

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	62	-	62
Non-current fair value of financial instruments	-	-	-
	62	-	62

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	61	-	61
Non-current fair value of financial instruments	-	-	-
	61	-	61

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	(100)	14	(86)
Non-current fair value of financial instruments	-	-	-
	(100)	14	(86)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
January 1, 2020 – March 31, 2020	Oil - swap	15,000	63.74	63.74

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

Total ($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	83	14	97
Non-current fair value of financial instruments	-	-	-
	83	14	97

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US$45,000 (CAD$58,900) decrease in the fair value of financial instruments at June 30, 2019, while a US$1.00 decrease would result in an increase of approximately US$45,000 (CAD$58,900) in the fair value of the instruments.

Subsequent to June 30, 2019, hedges were placed on 50% of Q1 fiscal 2021 estimated production for April 2020 at US$59.49/bbl, May 2020 at US$59.27/bbl and June 2020 at US$59.08/bbl.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not exposed to interest rate risk on its cash and cash equivalents at June 30, 2019 as the funds are not invested in interest-bearing instruments. The Company's Credit Facility carries a floating interest rate based on quoted US dollar LIBOR rates. The Company had no interest rate derivatives at June 30, 2019.

For the three months ended June 30, 2019, a 1% increase in US LIBOR would increase interest expense by $41,000.

17. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s) For the three months ended June 30	2019	2018
Trade and other receivables	573	611
Prepaid expenses and deposits	(4)	9
Trade and other payables	(619)	(414)
Effect of change in foreign exchange rates	(21)	(47)
	(71)	159
Attributable to:		
Operating	329	144
Investing	(400)	48
Financing	-	(33)
	(71)	159

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

Cash interest paid and received ($000s) For the three months June 30	2019	2018
Cash interest paid	243	253
Cash interest received	1	7

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.

At June 30, 2019, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and three wells with fracs and casing	February 2021	12.9
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 June 30, 2019 at an exchange rate of AUS$1.00 = CAD$0.9180.

At June 30, 2019, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	698	155	311	232	-
Decommissioning and restoration	1,926	-	547	-	1,378
	2,624	155	858	232	1,378

19. SEGMENTED INFORMATION

As at June 30, 2019, the Company has two reportable operating segments, being the Australian 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 three months ended June 30, 2019	**Australia**	**Corporate**	**Total**
Revenue	1,962	-	1,962
Interest revenue	1	-	1
Interest expense	301	4	305
Depletion and depreciation	340	14	354
Impairment	20	-	20
Net loss	(433)	(317)	(750)
Exploration and evaluation expenditures	10	-	10
Petroleum and natural gas property expenditures	1,270	-	1,270
($000s)			
June 30, 2019			
Exploration and evaluation assets	9,410	-	9,410
Petroleum and natural gas properties	26,514	-	26,514

($000s)			
For the three months ended June 30, 2018	**Australia**	**Corporate**	**Total**
Revenue	3,215	-	3,215
Interest revenue	7	-	7
Interest expense	243	-	243
Depletion and depreciation	378	3	381
Impairment	145	-	145
Net loss	(5)	(481)	(486)
Exploration and evaluation expenditures	160	-	160
Petroleum and natural gas property expenditures	141	-	141
($000s)			
June 30, 2018			
Exploration and evaluation assets	9,939	-	9,939
Petroleum and natural gas properties	26,337	40	26,377

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
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG