Bengal Energy Ltd.

International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended September 30, 2020 and 2019

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 and six months ended September 30, 2020.

This MD&A dated November 9, 2020 should be read in conjunction with the Company's interim condensed consolidated financial statements and related notes for the quarter ended September 30, 2020. The interim condensed consolidated financial statements of the Company have been prepared in accordance with International Accounting Standards (IAS) 34.

The functional currency of the Company's operating subsidiary, Bengal Energy (Australia) Pty Ltd. ("Bengal Australia"), 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, 2020 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended September 30, 2020 may be referred to as "second quarter fiscal 2021", "Q2 fiscal 2021", "Q2 FY 2021", "current quarter", and "the quarter". The comparative three months ended September 30, 2019, may be referred to as "second quarter fiscal 2020", "Q2 fiscal 2020", and "prior year's quarter".

SECOND QUARTER FISCAL 2021 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $1.3 million in the second quarter fiscal 2021, which is 47% lower than the $2.4 million recorded in Q2 fiscal 2020. Fiscal 2021 continues to be severely impacted by low oil prices as compared to Fiscal 2020. US Brent, during the current quarter averaged $42.96 versus $61.93 for the same quarter in fiscal 2020.
- **Hedging** – During the current quarter, forward fixed-price contracts contributed $0.3 million to the company's cash flow as compared to $0.3 million for Q2 fiscal 2020. For the six months ending September fiscal 2021, the hedging program has contributed $0.8 million as compared to $0.3 million for the six months ended September fiscal 2020. The current hedging program is expected to provide $58-$59/bbl per month on 50% of Bengal share of production for the remaining calendar year**.**
- **Cash from Operations** – Bengal generated net cash used in operating activities ($0.2) million during Q2 fiscal 2021 compared to $0.5 million of cash from operations in Q2 fiscal 2020. The primary reason for the negative cash from operations was the low commodity price which resulted in lower sales revenue.
- **Net Loss** – Bengal reported a net loss of $0.2 million for the current quarter compared to a net income of $0.2 million in the second quarter fiscal 2020. The primary driver for the net loss for Q2 fiscal 2021 was weak realised oil prices, partially offset by foreign exchange gains.
- **Bank Debt maturity extension -** On September 30, 2020, Westpac Banking Corporation ("Westpac'') agreed to extend the maturity of the Credit Facility (as defined herein) from October 30, 2020 to February 28, 2021. The company continues to work with Westpac to negotiate a longer term debt maturity for its Credit facility.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 21,247 bbls, which is a 30% decrease from the 30,667 bbls produced in the second quarter fiscal 2020. The current quarter production averaged 231 bbls/day compared to 333 bbls /day produced in the second quarter fiscal 2020. The decrease in production is a result of natural reservoir decline and a lack of drilling activity.
- **Capital Expenditures** – Bengal incurred $0.1 million in capital expenditures during Q2 fiscal 2021 as compared to $0.5 million in Q2 fiscal 2020. The majority of the current quarter expenditure went to the continued funding of the waterflood pilot that will commence in calendar Q4 2020.

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, Tookoonooka, ATP 934 and four recently acquired petroleum licenses 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. In the case of ATP 752, with the presence of the producing Cuisinier Oil Field, offsetting and oil shows in the Murta zone as well as the deeper Jurassic Birkhead zone in the Hudson 1, Koki 1 and Barta 1 wells previously drilled and abandoned and the evidence of structural continuity from the 3 D seismic control acquired over the last few years applications for PCA's 205 and 206 were made on the Barta block and approved by the Queensland regulatory authority. These applications include a commercial viability report that indicates the area is likely to be commercially viable within the applied term. This allows for extra time to commercialize the resource. A similar application was made and approved for PCA 155 on the Wompi block and approved. These PCA's remain a part of the ATP until expiry. 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 has two PLs on the former ATP 752 Barta block, PL 303 and PL 1028, in addition to three PCAs, PCA 206, PCA 207 Barta West and PCA 155 Wompi block-Nubba/Yilgarn. Bengal also acquired four PLs adjacent to the 100% owned ATP 934 in Q2 FY 2020.

AUSTRALIA – Cooper Basin, Queensland

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

The Cuisinier oil field continues to produce very light high quality crude oil in line with expectations with net daily volumes for the period of 231 bbls/d of light crude oil. Planning and drilling location selection for the 2020 multi-well development and appraisal drilling campaign has been deferred due to the COVID-19 pandemic and due to current low oil prices. Timing of restarting the campaign will be re-assessed in future periods based on oil pricing and financial conditions at that time. A pilot reservoir pressure maintenance scheme (water flood pilot) is planned to commence injection during Q4 of calendar 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 ~~("C24").~~ 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 increase initial production up to 90 barrels of oil per day in aggregate from nearby producers and result in a modelled 160,000 barrels of additional oil recovery. Achieving these results would enable future water flood expansion phases currently in the initial planning stages. Apart from increased oil recovery in the offsetting wells, another major benefit is reduction in produced water treatment tariffs. These tariffs are currently incurred as produced water is exported and treated at the Cook facility. The tariff structure is a tiered volume-based arrangement and accordingly, the water injection scheme would allow the joint venture to reduce the overall operating cost for Cuisinier oil.

PCA 155 Nubba/Yilgarn (controlling permit ATP 752, Wompi Block) (38.08% WI).

The Company and its joint venture partners are planning to conduct an extended production test on the Nubba gas discovery well. Initially planned for Q4 calendar 2019, the project is now delayed until there is certainty over a tie in point that can be accessed at a reasonable connection cost. Plans to tie in the well are subject to commercial flow rates and gas reserves being achieved and are not expected until 2022.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned liquids-rich natural gas exploration block. In order to mitigate both financial and development risk, Bengal has done extensive state of the art geophysical work that has not been widely applied in Australia and which gives us a higher degree of confidence in the block and focuses our attention on the most likely prospects.

The Company announced a significant farm-out with a major Cooper Basin Explorer and Producer for a farm-in well on a portion of ATP 934. The farm in investor will earn a 60% interest in one well for 100% of the costs to drill and case one well. This 100% free carried well is planned for the second half of 2021. This well will assist in further de-risking the natural gas potential of the permit. (See Bengal press release dated July 28th, 2020).

On April 24, 2020, the Corporation received regulatory approval for a special amendment to the initial work program on ATP 934. As a condition of the approval of the special amendment, the Corporation agreed to relinquish an additional 17% of the acreage subject to the permit in addition to the 33% mandatory relinquishment for a total of 50% (240 sub-blocks) of the acreage at the end of the first term on the permit. The acreage subject to the 50% relinquishment was determined by Bengal and consisted of the least prospective land from a technical perspective and with the most challenging access conditions under the terms of the existing Environmental Authority granted by the regulator. In return, the Corporation was granted a reduction in the total commitment from $12.3 million to $1.2 million and does not expect to make any additional investments prior to the approval of a second term on the ATP. The company is currently working with the Government of Queensland on amending the commitment requirements and is expecting a resolution by the end of February 2021.

PL 114 Wareena, PL 157 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% W.I.)

As announced in the Bengal press release of September 12, 2019, the Company acquired a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market (collectively, the “Assets”). These non-productive PLs are highly compatible with and in close proximity to ATP 934. Receipt of all required regulatory approvals is expected to occur early in the fourth quarter of calendar 2020 to complete the acquisition. Bengal continues to integrate subsurface data from the PLs to enhance the Company’s understanding of ATP 934 and to finalize the selection of exploration and appraisal drilling locations.

Included in this program is an oil zone completion in a cased well which recovered 588 bbls/d of 37 degree API oil, based on a 105-minute test period when it was drilled in 2007. New test and API date will be confirmed upon re-entry process. Upon completion of a successful test, this well will be immediately equipped for production and the oil sold into the regional market. The Company is in discussions with potential industry and financial partners to fund this activity.

The 100% ownership of these assets presents an appraisal and development opportunity that will be operated by the Company and is seen to be not only complementary to its proven producing, non-operated Cuisinier asset, but also as a key stepping stone for Bengal’s natural gas platform with immediate market access to an existing pipeline providing the ability to commercialize future exploration success and continued development and exploration activity.

Synergies with ATP 934 Exploration Program

The acquired PL’s support Bengal's strategy to maximize its ownership and operatorship of its permits in the Cooper Basin of Australia. Bengal is currently examining funding alternatives to evaluate the new PLs and to drill up to three wells in calendar 2021-2022 period.

ATP 934 covers an area of 1,462 km^2 (360,000 acres) and is immediately surrounded by the newly acquired PLs. Bengal has identified and mapped six individual drilling prospects on the ATP 934 permit, some of which are directly offsetting the cased wells located on the PLs.

ATP 732 – Tookoonooka (100% W.I.)

In June 2019, the Company applied for an amendment to the Later Work Program (LWP) for the third term of ATP 732 permit, On October 22, 2019, the Company received approval from the Queensland regulatory authority for an amended LWP for the third, four-year term commencing April 1, 2019 to March 31, 2023. The approved LWP was revised to minimum activities of reprocessing seismic and inversion work with an estimated cost of $50K and geological and geophysical investigation at an estimated cost of $50K during the four-year term.

Business Development

The Company continues to engage in early stage confidential and non-binding discussions with a number of third parties respecting potential business development opportunities, including possible business combination transactions expected to assist in reducing combined costs, increasing scale and advancing external financing options. While discussions have continued throughout the COVID-19 pandemic, the unfavourable and volatile market conditions have posed a material challenge to advancing such discussions. The Company cautions that all discussions are preliminary and non-binding and there are no assurances that such discussions will advance or that any transaction will be pursued or ultimately be undertaken.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback amounts)	Three months ended September 30				Six months ended September 30			
		2020		2019		2020		2019
Oil revenue	$	1,260	$	2,576	$	2,359	$	4,538
Operating netback(1)	$	577	$	1,649	$	1,260	$	2,761
Cash flow from operations	$	(166)	$	527	$	169	$	843
Funds used in operations(2)	$	(67)	$	724	$	(277)	$	711
Per share ($) (basic and diluted)	$	(0.00)	$	0.01	$	(0.00)	$	0.01
Net (loss) income	$	(182)	$	(506)	$	218	$	(1,256)
Per share ($) (basic and diluted)	$	(0.00)	$	(0.00)	$	0.00	$	(0.01)
Adjusted net (loss) income(3)	$	(517)	$	177	$	(1,124)	$	(308)
Per share ($) (basic and diluted)	$	(0.01)	$	0.00	$	(0.01)	$	0.00
Capital expenditures	$	124	$	477	$	223	$	1,757
Oil volumes (bbls/d)		231		333		234		292
Netback(1)($/bbl)	$	27.15	$	53.78	$	29.39	$	51.74

(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 (used in) 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-to-date. Funds from (used in) 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 16.

(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 September 30		Six months ended September 30	
	2020	2019	2020	2019
Oil production (bbls/d)	231	333	234	292
Oil production (bbls)	21,247	30,667	42,864	53,355

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 September 30		Six months ended September 30	
		2020	2019	2020	2019
	Oil lifting				
	Volume (000s bbls)	22.5	24.6	45.8	48.9
	Weighted average price (US$/bbl)	46.18	65.53	33.54	54.31
A.	Sales ($000's)	1,683	2,208	2,314	4,504
	Pipeline oil				
	Volume (000s bbls), change	(5.6)	6.0	(2.4)	4.4
	Price (US$/bbl), change	(0.55)	(7.52)	15.42	(15.99)
B.	Net sales ($000's)	(423)	368	45	34
A.+B.	Total oil sales ($000s)	1,260	2,576	2,359	4,538

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 Q2 fiscal 2021 was significantly impacted by the decline in US Brent as compared to Q2 fiscal 2020. The realized weighted average price of oil lifting sales was US $46.18/bbl for Q2 fiscal 2021 as compared to US$65.53/bbl for Q2 FY 2020. When combined with lower oil lifting volumes in Q2 fiscal 2021 of 22.5K bbls as compared to 24.6K bbls in Q2 fiscal 2020, oil lifting sales were lower at $1.7 million for the current quarter as compared to $2.2 million for Q2 fiscal 2020. During the current quarter, the value of the pipeline oil declined by $0.4 million due to a combination of a decline in oil pipeline volume of 5,600 bbls and a reduction in price of US$0.55/bbl. When oil lifting sales are adjusted for the change in value of the pipeline oil for the current quarter of ($0.4) million, Bengal's total oil sales are $1.3 million for the current quarter as compared to $2.56 million for Q2 fiscal 2020.

The following table outlines average benchmark prices:

	Three months ended September 30		Six months ended September 30	
	2020	2019	2020	2019
Brent oil ($/bbl)	57.14	81.75	49.16	87.02
Brent oil (US$/bbl)	42.96	61.93	36.15	65.43
Number of CAD$ for 1 AUS$	0.95	0.90	0.93	0.92
Number of CAD$ for 1 US$	1.33	1.32	1.36	1.33

($000s)

Netbacks

	Three months ended September 30		Six months ended September 30	
	2020	**2019**	**2020**	**2019**
Oil sales	1,260	2,576	2,359	4, 538
Realized gain on financial instruments	261	253	806	347
Royalties	(76)	(147)	(142)	(248)
Operating expenses	(868)	(1,033)	(1,763)	(1,876)
Netback	577	1,649	1,260	2,761
($/bbl)				
Oil sales	59.30	84.00	55.03	85.05
Realized gain on financial instruments	12.28	8.25	18.80	6.50
Royalties	(3.58)	(4.79)	(3.31)	(4.65)
Operating expenses	(40.85)	(33.68)	(41.13)	(35.16)
Netback	27.15	53.78	29.39	51.74

Operating netbacks in Q2 fiscal 2021 were $0.6 million or $27.15/bbl compared to Q2 fiscal 2020 at $1.6 million or $53.78/bbl. For the six months ended Q2 fiscal 2021, operating netback was $1.3 million or $29.39/bbl. This compares to $2.8 million or $51.74/bbl for the six months ended Q2 fiscal 2020. Operating expenses for the current quarter were $40.85/bbl as compared to $33.68/bbl for Q2 fiscal 2020. Bengal had a realized gain on financial instruments of $0.3 million due to the approximate US$57/bbl hedges throughout the three months ended Q2 fiscal 2021. Royalty rates came in at 6% of oil sales for Q2 fiscal 2021 or $3.58/bbl as compared to 6% of oil sales or $4.79/bbl for Q2 fiscal 2020.

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. However, as agreed in the September 30, 2020 debt extension letter, Westpac has waived the hedging requirement along with financial covenants until February 28, 2021. Not withstanding the waiver, the company continues to evaluate and review methods to protect the Company against the possibility of continued low commodity prices.

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 September 30, 2020, the Company has the following derivative contracts:

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl	Fair value ($000s)
October 1, 2020 – October 31, 2020	Oil - swap	4,200	59.27	59.27	100
November 1, 2020 – November 30, 2020	Oil - swap	4,200	58.95	58.95	95
December 1, 2020 – December 31, 2020	Oil - swap	4,200	58.63	58.63	91
Total					286

The fair value of the financial contracts outstanding as at September 30, 2020 is $0.3 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period, having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the six months ended September 30, 2020, the derivative commodity contracts resulted in a realized gain of $0.8 million (September 30, 2019 – gain of $0.3 million) and an unrealized loss of $1.3 million (September 30, 2019 – loss of $0.1 million).

Royalties

	Three months ended September 30		Six months ended September 30	
	2020	**2019**	**2020**	**2019**
Royalty expense ($000s)	76	147	142	248
$/bbl	3.58	4.79	3.31	4.65
% of revenue	6	6	6	5

During the current quarter, the Queensland Government increased oil royalties from 10% to 11.25%. The royalty rate is applied to gross revenues after deducting allowable capital, transportation and operating costs.

Royalty rates came in at 6% of oil sales for Q2 fiscal 2021 or $3.58 per bbl as compared to 6% of oil sales or $4.79/ bbl for Q2 fiscal 2020. The company continues to expect the ongoing royalty rate to remain at 6% due to the consistent high level of capital investment which is a reduction in the calculation of the royalty rate paid.

Operating Expenses

($000s) Operating expenses	Three months ended September 30		Six months ended September 30	
	2020	2019	2020	2019
Production	195	126	378	278
Transportation	673	907	1,385	1,598
	868	1,033	1,763	1,876
Production - $/bbl	9.18	4.11	8.82	5.21
Transportation - $/bbl	31.68	29.58	32.30	29.95
	40.86	33.69	41.12	35.16

Total operating expense during the second quarter fiscal 2021 was $0.9 million or $40.86/bbl. This compares to $1.0 million of operating expenses for the second quarter fiscal 2020 or $33.69/bbl. Operating expenses per barrel were higher in the current quarter due to increased field production costs, water processing and work over activity as compared to Q2 fiscal 2020.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended September 30		Six months ended September 30	
	2020	2019	2020	2019
Total G&A	540	879	1,046	1,831
Capitalized G&A	-	(157)	(7)	(178)
Net G&A	540	722	1,039	1,653

Total G&A expense for Q2 fiscal 2021 was $0.5 million as compared to $0.7 million for Q2 fiscal 2020. There was no capitalized G&A during the current quarter due to the very low capital spend in the current quarter. The lower G&A expense quarter over quarter is due to the significant cost reduction programs implemented by management over the past 6 months in fiscal 2021.

Share-based Compensation ("SBC")

($000s) SBC	Three months ended September 30		Six months ended September 30	
	2020	2019	2020	2019
Expensed share-based compensation	-	6	5	17
Capitalized share-based compensation	-	-	-	1
	-	6	5	18

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. There were no share based compensation grants provided during the current quarter.

Depletion and Depreciation (DD&A)

($000s) DD&A	Three months ended September 30 2020	2019	Six months ended September 30 2020	2019
Petroleum and natural gas properties	343	442	677	782
Other assets	1	1	3	3
Right-of-use assets	12	12	24	24
	356	455	704	809
Petroleum and natural gas properties - $/bbl	16.14	14.41	15.79	14.66

Production in Q2 fiscal 2021 was 21,247 bbls compared with 30,667 bbls in Q2 fiscal 2020. The lower production in Q2 fiscal 2021 when compared to Q2 fiscal 2020 resulted in the lower depletion expense. On a per barrel basis, the lower production volume in Q2 fiscal 2021 compared to Q2 fiscal 2020 results in a higher depletion per barrel cost because the depletable cost base has not declined at the same rate.

Impairment Expense

($000s) Impairment expense	Three months ended September 30 2020	2019	Six months ended September 30 2020	2019
Exploration and evaluation assets	-	-	-	10
Petroleum and natural gas properties	-	-	-	10
	-	-	-	20

During Q1 and Q2 fiscal 2021, the Company did not take any impairment charges.

Finance Expense

($000s) Finance expense	Three months ended September 30 2020	2019	Six months ended September 30 2020	2019
Interest income	-	-	-	(1)
Accretion expense on decommissioning and restoration liability	5	8	9	17
Interest on lease liability	3	3	6	7
Interest on credit facility	256	322	521	623
	264	333	536	646

The extension of the company's credit facility maturity date from October 30, 2020 to February 28, 2021 which extends the amortization of borrowing costs and a reduction in the interest rate of 1.63 % resulted in a lower effective interest rate in the current quarter as compared to the same quarter in fiscal 2020.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended September 30		Six months ended September 30	
	2020	2019	2020	2019
Geological and geophysical	42	78	99	138
Drilling	-	14	12	148
Completions	82	233	112	1,319
Acquisition	-	152	-	152
	124	477	223	1,757
Exploration and evaluation expenditures	-	-	-	10
Development and production expenditures	124	477	223	1,747
	124	477	223	1,757

Capital expenditures of $0.1 million in Q2 fiscal 2021 (geological and geophysical, drilling and completions) relates to payments for the waterflood pilot that will commence in calendar Q4 2020.

CREDIT FACILITY

The Company initially entered into a US $25 million reserves based revolving credit facility (the "Credit Facility") in October 2014, placing an initial draw of US $14 million. The facility is secured by and available to the Company's producing assets in the Cuisinier field in Australia's Cooper Basin. On August 26, 2016, the Company repaid US $1.5 million.

On May 29, 2019, the Company and Westpac entered into an amendment to its reserved based revolving Credit Facility that had 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. The Credit Facility requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. The interest rate under the Credit Facility remained unchanged at US LIBOR plus 3.75%.

On November 5, 2019, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to October 31, 2020. All previous terms and conditions remain the same except for the interest rate which moved from 3.75% to 3.95%.

On September 30, 2020, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to February 28, 2021. All previous terms and conditions remain the same except for the Credit Facility's reserve-based covenants have been waived including hedging requirements through February 28, 2021.

Management continues to discuss with Westpac the opportunity to lengthen the term of the Credit Facility particularly in light of the recent acquisition which has the potential to both increase reserves and improve cash flow. 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 table below indicates the payment schedule for the Credit Facility:

(US$000s) Credit Facility	
Fiscal year 2021	12,369

SHARE CAPITAL

Trading history	Three months ended September 30		Six months ended September 30	
	2020	2019	2020	2019
High ($)	0.06	0.11	0.06	0.13
Low ($)	0.03	0.07	0.02	0.06
Close ($)	0.04	0.09	0.04	0.09
Volume (000s)	2,470	975	6,146	1,761
Shares outstanding (000s)	102,267	102,267	102,267	102,267
Weighted average shares outstanding (000s) - basic and diluted	102,267	102,267	102,267	102,267

At November 09, 2019, there were 102,266,694 common shares issued and outstanding, together with 2,685,000 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 current financial liabilities consist of trade and other payables, lease liability and Credit Facility, amounting to $18.3 million at September 30, 2020 (March 31, 2020 - $18.9 million). The current assets consist of accrued revenue in the form of pipeline oil and unallocated cash calls paid to the Joint venture operator in the amount of $1.4 million at September 30 2020.

At September 30, 2020, the Company had a working capital deficiency of $15.1 million, including cash and short-term deposits of $1.1 million and restricted cash of $0.04 million, compared to a working capital deficiency of $14.4 million at March 31, 2020. The working capital deficiencies are primarily a result of the reclassification of the Credit Facility of $16.8 million maturing in February 2021. The Company has no available undrawn debt capacity under its Credit Facility.

At September 30, 2020, the Company has fully drawn on its US$12.4 million Credit Facility that matures in February 2021. In Q1 fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced to $1.1 million. In exchange for the reduction in commitment, the Company will relinquish 50% of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021.

Management is in discussions with Westpac to further extend the Credit Facility. Management anticipates 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 the Credit Facility will be extended or 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

Going concern

The condensed consolidated financial statements included in this MD&A have been prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

As at September 30, 2020, the Company had a working capital deficiency of $15.1 million. The Company has no available undrawn debt capacity under its credit facility which will expire on February 28, 2021. As at September 30, 2020, the Company's covenants with respect to its debt service coverage ratio ("DSCR") (refer to Note 9 in the Financial Statements) had been waived through February 28, 2021. The Company has significant capital work commitments associated with its exploration and evaluation assets.

The Company’s ability to continue as a going concern is dependent upon the ability to generate positive cash flow from operating activities and to renew the current Credit Facility or to raise additional financing to meet its future development costs associated with petroleum and natural gas assets and to continue with other capital projects and operations. There can be no assurances that the facility will be renewed or additional sources of funding will be available for the Company. These matters cause material uncertainty which may cast significant doubt on the Company’s ability to continue as a going concern.

These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern assumption were not appropriate, adjustments would be necessary in the carrying value of the Company’s assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

The majority of the Company’s oil sales are benchmarked on US$ Brent prices. 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.

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

(US$000s)	
Credit Facility	
Fiscal year 2021	12,369

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.

COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 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 up to three wells.

At September 30, 2020, 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 up to three wells	February 2021	1.1
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at September 30, 2020 at an exchange rate of AUS$1.00 = CAD$ 0.9541.

At September 30, 2020, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations October 2020 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	504	155	321	28	-
Decommissioning and restoration	4,056	-	707	-	3,279
	4,560	155	1,028	28	3,279

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Sep 30 2020 Q2 2021	Jun 30 2020 Q1 2021	Mar 31 2020 Q4 2020	Dec 31 2019 Q3 2020	Sep 30 2019 Q2 2020	June 30 2019 Q1 2020	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019
Oil sales	1,260	1,099	1,140	2,425	2,576	1,962	2,667	2,014
Cash flow (used in) from operations	(166)	335	27	259	527	316	635	434
Funds (used in) from operations[(1)]	(67)	(210)	(849)	599	724	(13)	842	(247)
Per share – basic and diluted ($)	(0.00)	0.00	(0.01)	0.01	0.01	0.00	0.01	(0.01)
Net (loss) income	(182)	400	(2,196)	556	(506)	(750)	(2,144)	883
Per share – basic and diluted ($)	(0.00)	0.00	(0.02)	0.01	(0.00)	(0.01)	(0.02)	0.01
Capital expenditures	124	99	(68)	346	477	1,280	2,473	298
Working capital (deficiency)	(15,129)	(14,908)	(14,434)	(13,823)	(14,120)	(13,964)	(12,740)	6,331
Total assets	41,138	41,097	39,572	41,391	40,849	40,373	42,489	44,291
Shares outstanding (000s)	102,267	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	231	238	254	280	333	249	281	300
Operating netback[(1)] ($/bbl)	27.15	31.60	10.77	59.68	53.78	49.01	76.82	22.54

(1) See "Non-IFRS Measurements" on page 17 of this MD&A.

A significant decline in US Brent prices during Q3 fiscal 2019 was responsible for the low oil sales and funds from operations. Cash flow from operations has been consistent over most quarters except for Q4 fiscal 2020 when revenue and cash flow were significantly impacted by low commodity prices. Over the years, net losses have been affected by fluctuations in foreign exchange, hedging gains and losses and capital development. Net income in both Q3 fiscal 2020 and Q1 fiscal 2021 were the result of favorable changes in foreign exchange. Working capital deficiency began in Q4 fiscal 2019 due to the reclassification of the Company's debt from long term to current due to the delay in negotiating an extension to the maturity date. The collapse of oil prices and the onset of COVID-19 in early March 2020 significantly affected both production and in particular pricing, impacting sales revenue in Q1 and Q2 fiscal 2021. In addition, due to the poor economic environment, capital expenditures have been limited in Q1 and Q2 fiscal 2021 and will remain so for the rest of the calendar year.

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at September 30, 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 fiscal 2020 annual Management's Discussion and Analysis dated June 25, 2020.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies applied are consistent with those of the previous financial year as described in Note 3 of the Company's consolidated financial statements for the year ended March 31, 2020.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netback, operating netback per barrel, 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. Operating netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Operating netback per barrel equals operating 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 September 30 2020	Three months ended September 30 2019	Six months ended September 30 2020	Six months ended September 30 2019
Cash (used in) from operating activities	(166)	527	169	843
Changes in non-cash working capital	99	197	(446)	(132)
Funds (used in) from operations	(67)	724	(277)	711

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

($000s)	Three months ended September 30 2020	Three months ended September 30 2019	Six months ended September 30 2020	Six months ended September 30 2019
Net (loss) income	(182)	(506)	218	(1,256)
Unrealized loss on financial instruments	303	38	1,254	113
Unrealized foreign exchange (gain) loss	(638)	645	(2,596)	815
Non-cash impairment of non-current assets	-	-	-	20
Adjusted net (loss) income	(517)	177	(1,124)	(308)

ABBREVIATIONS

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

bbl	-	barrel
bbls	-	barrels
bbls/d	-	barrels per day
bopd	-	barrels of oil per day
$/bbl	-	dollars per barrel
ft^3	-	cubic feet
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 is provided in Bengal's Annual Information Form dated June 29, 2020 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.

COVID-19

The COVID-19 pandemic has resulted in emergency actions taken by governments worldwide, which has had an effect on effect on the Company. The actions taken by these governments have typically included, but is not limited to travel bans, mandatory and self-imposed quarantines and isolations, social distancing, and the closing of non-essential businesses which has had significant negative effects on economies, including a substantial decline in crude oil and natural gas demand. Additionally, such actions have resulted in volatility and disruptions in regular business operations, supply chains and financial markets as well as declining trade and market sentiment. COVID-19 as well as other factors have resulted in the deepest drop in crude oil prices that global markets have seen since 1991. With the rapid spread of COVID-19, oil prices and the global equity markets have deteriorated significantly and are expected to remain under pressure. The extreme supply/demand imbalance is anticipated to cause a reduction in industry spending in 2020. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. COVID-19 also poses a risk on the financial capacity of Bengal's contract counterparties and potentially their ability to perform contractual obligations.

The full extent of the risks surrounding the COVID-19 pandemic is continually evolving. The following risks disclosed in our Annual Information Form for the year ended March 31, 2020 may be exacerbated as a result of the COVID-19 pandemic: market risks related to the volatility of oil and gas prices, volatility of foreign exchange rates, volatility of the market price of common shares, and hedging arrangements; operational risks related to increasing operating costs or declines in production levels, operator performance and payment delays, government regulations, ability to obtain additional financing, and variations in foreign exchange rates; and other risks related to cyber-security as our workforce moves to remote connections, accounting adjustments, effectiveness of internal controls, and reliance on key personnel, management, and labour.

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 "forward-looking information" (collectively referred to as "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;*
- *The adverse impacts on the Company as a result of the current challenging economic climate;*
- *Expectations regarding Bengal's current hedging program;*

- *Bengal's ability to negotiate a longer term debt maturity for its credit facility;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *Bengal's drilling program and waterflood pilot;*
- *The timing and re-assessment of restarting the planning and drilling selection for the 2020 multi-well development and appraisal drilling campaign;*
- *The timing of the planned pilot reservoir pressure maintenance scheme on the Barta Block PL 303 and the anticipated resulting production increases in offsetting wells, future waterflood expansion phases, and reduced operating costs;*
- *The timing of the planned extended production test on the Nubba gas discovery well and plans to tie in the well;*
- *The planned 100% free carried well on the ATP 934 Barrolka and the expected assistance in de-risking the natural gas potential of the permit;*
- *Bengal's ability to negotiate amendments to the commitment requirements on ATP 934 Barrolka with the Government of Queensland and the timing of such negotiations;*
- *The timing of receipt of all required regulatory approvals for the PLs;*
- *The timing of equipping for production cased wells on the four acquired production licenses and the potential of obtaining industry and financial partners to fund the activities on the PLs;*
- *The continued integration of subsurface data from production licenses in the selection of exploration and appraisal drilling locations;*
- *The appraisal and development opportunities offered by the 100% ownership of the PLs;*
- *The continued engagement in early stage discussions with third parties with respect to potential business development opportunities including possible business combination transactions;*
- *The timing and intention to place hedges on future production;*
- *Projections of market prices and costs including, but not limited to, expected royalty rates;*
- *Expectations that operating and capital requirements will be met out of operation cash flows and alternative forms of capital raising;*
- *Bengal's ability to finance its working capital deficiency and to source funds for the same;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs; and*
- *That funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures 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 2021 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:

- *The continuing adverse impact of COVID-19 on economic activity and demand for oil and natural gas;*
- *Uncertainties associated with the COVID-19 pandemic;*
- *Willingness of the Company's lenders to negotiate;*
- *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, 2020 (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.

Rider 2:

[Test Rates

References in this MD&A to production test rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results are historical and not indicative of expected production.]

Rider 3:

Internal Estimates

Certain information contained herein is based on estimated values the Company believes to be reasonable and are subject to the same limitations as discussed under "Forward-looking Statements" above.

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

Bengal
ENERGY LTD.

Interim Condensed Consolidated Financial Statements

(Unaudited)

Three and Six Months Ended September 30, 2020 and 2019

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(unaudited)

As at		September 30 2020	March 31 2020
Assets	Notes		
Current assets:			
Cash and cash equivalents		$ 1,055	$ 998
Restricted cash		40	140
Trade and other receivables	5	1,416	1,639
Prepaid expenses and deposits		224	126
Fair value of financial instruments	17	286	1,447
		3,021	4,350
Exploration and evaluation assets	6	9,794	8,930
Property, plant and equipment	7	28,323	26,292
Total assets		$ 41,138	$ 39,572
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	8	$ 1,257	$ 1,041
Current portion of credit facility	9	16,843	17,695
Current portion of lease liability	10	50	48
		18,150	18,784
Decommissioning and restoration liability	11	4,056	3,690
Lease liability	10	131	156
		22,337	22,630
Shareholders' equity:			
Share capital	12	98,100	98,100
Contributed surplus		7,866	7,861
Accumulated other comprehensive loss		(15)	(1,651)
Deficit		(87,150)	(87,368)
		18,801	16,942
Total liabilities and shareholders' equity		$ 41,138	$ 39,572

Going concern (Note 2)

Commitments (Note 19)

See accompanying notes to the interim condensed consolidated financial statements.

BENGAL ENERGY LTD.

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

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

	Notes	Three months ended September 30 2020	Three months ended September 30 2019	Six months ended September 30 2020	Six months ended September 30 2019
Revenue					
Oil sales	14	$ 1,260	$ 2,576	$ 2,359	$ 4,538
Royalties		(76)	(147)	(142)	(248)
		1,184	2,429	2,217	4,290
Realized gain on financial instruments	17	261	253	806	347
Unrealized loss on financial instruments	17	(303)	(38)	(1,254)	(113)
		1,142	2,644	1,769	4,524
Expenses					
General and administrative		540	722	1,039	1,653
Operating		868	1,033	1,763	1,876
Depletion and depreciation	7	356	455	704	809
Impairment	6,7	-	-	-	20
Share-based compensation		-	6	5	17
Foreign exchange (gain) loss		(605)	601	(2,397)	759
		1,159	2,817	1,114	5,134
Other expense					
Other		(99)	-	(99)	-
Finance expense	16	264	333	536	646
Net (loss) income		(182)	(506)	218	(1,256)
Exchange differences on translation of foreign operations		315	(518)	1,636	(1,158)
Comprehensive income (loss)		$ 133	$ (1,024)	$ 1,854	$ (2,414)
Net (loss) income per share - basic & diluted	15	$ (0.00)	$ (0.00)	0.00	$ (0.01)
Weighted average shares outstanding (000s) – basic and diluted	15	102,267	102,267	102,267	102,267

See accompanying notes to the interim condensed consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)

(unaudited)

For the six months ended September 30	2020	2019
Share capital		
Balance at beginning and end of period	$ 98,100	$ 98,100
Contributed surplus		
Balance at beginning of period	7,861	7,832
Share-based compensation – expensed	5	17
Share-based compensation – capitalized	-	1
Balance at end of period	7,866	7,850
Accumulated other comprehensive loss		
Balance at beginning of period	(1,651)	(4)
Exchange differences translation of foreign operations	1,636	(1,158)
Balance at end of period	(15)	(1,162)
Deficit		
Balance at beginning of period	(87,368)	(84,472)
Net income (loss)	218	(1,256)
Balance at end of period	(87,150)	(85,728)
Total shareholders' equity	$ 18,801	$ 19,060

See accompanying notes to the interim condensed consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

(unaudited)

	Notes	Three months ended September 30 2020	Three months ended September 30 2019	Six months ended September 30 2020	Six months ended September 30 2019
Operating activities:					
Net (loss) income		$ (182)	$ (506)	$ 218	$ (1,256)
Add (deduct) non-cash items					
Depletion and amortization		356	455	704	809
Accretion on decommissioning and restoration liability		5	8	9	17
Accretion on credit facility		86	75	123	138
Share-based compensation		-	6	5	17
Interest on lease liability		3	3	6	7
Lease incentive		-	-	-	31
Impairment		-	-	-	20
Unrealized loss on financial Instruments		303	38	1,254	113
Unrealized foreign exchange (gain) loss		(638)	645	(2,596)	815
Funds (used in) from operations		(67)	724	(277)	711
Change in non-cash working capital	18	(99)	(197)	446	132
Net cash (used in) from operating activities		(166)	527	169	843
Investing activities:					
Exploration and evaluation expenditures	6	-	-	-	(10)
Petroleum and natural gas property expenditures	7	(124)	(477)	(223)	(1,747)
Change in restricted cash		-	-	100	-
Change in non-cash working capital	18	117	(216)	(31)	(616)
Net cash used in investing activities		(7)	(693)	(154)	(2,373)
Financing activities:					
Lease payments		(15)	(15)	(29)	(30)
Facility extension fees		-	(13)	-	(33)
Change in non-cash working capital	18	(4)	10	(4)	10
Net cash used in financing activities		(19)	(18)	(33)	(53)
Net decrease in cash and cash equivalents		(192)	(184)	(18)	(1,583)
Cash and cash equivalents, beginning of period		1,230	1,436	998	2,891
Impact of foreign exchange on cash and cash equivalents		17	(31)	75	(87)
Cash and cash equivalents, end of period		$ 1,055	$ 1,221	$ 1,055	$ 1,221

See accompanying notes to the interim condensed 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 condensed 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.

The Company has its registered office at 2400, 525 – 8th Avenue SW, Calgary, Alberta T2P 1G1 and its head and principal office at 2000, 715 - 5th Ave SW, Calgary, Alberta, Canada, T2P 2X6.

2. BASIS OF PREPARATION AND GOING CONCERN

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 condensed 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, 2020 except as noted below in Note 3. 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, 2020.

These financial statements were approved and authorized for issuance by the Board of Directors on November 9, 2020.

These financial statements have been prepared on a historical cost basis, except for commodity contracts as discussed in Note 17.

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.

Going concern

These financial statements have been prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

As at September 30, 2020, the Company had a working capital deficiency of $15.1 million. The Company has no available undrawn debt capacity under its credit facility which will expire on February 28, 2021. As at September 30, 2020, the Company's covenants with respect to its debt service coverage ratio ("DSCR") (refer to Note 9) had been waived through February 28, 2021. The Company has significant capital work commitments associated with its exploration and evaluation assets.

The Company's ability to continue as a going concern is dependent upon the ability to generate positive cash flow from operating activities and to renew the current Credit Facility or to raise additional financing to meet its future development costs associated with petroleum and natural gas assets and to continue with other capital projects and operations. There can be no assurances that the facility will be renewed or additional sources of funding will be available for the Company. These matters cause material uncertainty which may cast significant doubt on the Company's ability to continue as a going concern.

These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern assumption were not appropriate, adjustments would be necessary in the carrying value of the Company's assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies used are consistent with those of the previous financial year as described in Note 3 of the Company's consolidated financial statements for the year ended March 31, 2020 except for the below.

Government Grants

Government grants related to assets are initially recognized by the Company as deferred income at fair value if there is reasonable assurance that they will be received and the Company will comply with the conditions associated with the grant; they are then recognized in profit or loss as other income on a systematic basis over the useful life of the asset. Grants that compensate the Company for expenses incurred are recognized in profit or loss on a systematic basis in the periods in which the expenses are recognized.

4. MANAGEMENT JUDGMENTS AND 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. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are out-lined below.

In March 2020, the World Health Organization declared a global pandemic related to COVID-19. In addition, global commodity prices have declined significantly due to disputes between major oil producing countries combined with the negative impact to oil demand from the COVID-19 pandemic. Governments worldwide, including those in Canada and Australia, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The current challenging economic climate may have significant adverse impacts on the Company, including material declines in revenue and cash flows, and related impacts to working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows to meet the Company's current and future obligations. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time.

A full list of the critical judgments in applying accounting policies and key sources of estimation uncertainty can be found in the Company's consolidated financial statements for the year ended March 31, 2020. Estimates and judgements made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

5. 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)	September 30, 2020	March 31, 2020
Due from joint venture partners	1,393	1,628
Other receivables	23	11
	1,416	1,639

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

($000s)	
Balance, April 1, 2019	9,711
Additions	22
Impairment	(10)
Exchange adjustments	(793)
Balance, March 31, 2020	8,930
Exchange adjustments	864
Balance, September 30, 2020	9,794

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

($000s)	
ATP 732P – Tookoonooka	4,743
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,437
ATP 934 – Barrolka	1,750
Balance, March 31, 2020	8,930

($000s)	
ATP 732P – Tookoonooka	5,203
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,672
ATP 934 – Barrolka	1,919
Balance, September 30, 2020	9,794

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.

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, April 1, 2019	45,367	344	-	45,711
Additions	1,752	-	-	1,752
Acquisition	1,798	-	-	1,798
Adoption of IFRS 16	-	-	219	219
Capitalized share-based compensation	1	-	-	1
Change in decommissioning and restoration liability	368	-	-	368
Exchange adjustments	(5,464)	-	-	(5,464)
Balance, March 31, 2020	43,822	344	219	44,385
Additions	223	-	-	223
Exchange adjustments	6,111	-	-	6,111
Balance, September 30, 2020	50,156	344	219	50,719

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment losses:				
Balance, April 1, 2019	18,937	312	-	19,249
Depletion and depreciation	1,343	7	47	1,397
Impairment	636	-	-	636
Exchange adjustments	(3,189)	-	-	(3,189)
Balance, March 31, 2020	17,727	319	47	18,093
Depletion and depreciation	677	3	24	704
Exchange adjustments	3,599	-	-	3,599
Balance, September 30, 2020	22,003	322	71	22,396

($000s)				
Net carrying amount:				
At March 31, 2020	26,095	25	172	26,292
At September 30, 2020	28,153	22	148	28,323

At September 30, 2020, there were no indicators of impairment or impairment reversal. As a result, no impairment or impairment reversal testing was conducted.

During the six months ended September 30, 2020, the Company capitalized $0.0 million of general and administrative expense (2019 - $0.2 million).

The calculation of depletion for the three and six months ended September 30, 2020 included $59.7 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2020 - $59.7 million).

7. PROPERTY, PLANT AND EQYIPMENT (“PP&E”)

($000s)

	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, April 1, 2019	45,367	344	-	45,711
Additions	1,752	-	-	1,752
Acquisition	1,798	-	-	1,798
Adoption of IFRS 16	-	-	219	219
Capitalized share-based compensation	1	-	-	1
Change in decommissioning and restoration liability	368	-	-	368
Exchange adjustments	(5,464)	-	-	(5,464)
Balance, March 31, 2020	43,822	344	219	44,385
Additions	223	-	-	223
Exchange adjustments	6,111	-	-	6,111
Balance, September 30, 2020	50,156	344	219	50,719

($000s)

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Accumulated depletion, depreciation and impairment losses:				
Balance, April 1, 2019	18,937	312	-	19,249
Depletion and depreciation	1,343	7	47	1,397
Impairment	636	-	-	636
Exchange adjustments	(3,189)	-	-	(3,189)
Balance, March 31, 2020	17,727	319	47	18,093
Depletion and depreciation	677	3	24	704
Exchange adjustments	3,599	-	-	3,599
Balance, September 30, 2020	22,003	322	71	22,396

($000s)

Net carrying amount:				
At March 31, 2020	26,095	25	172	26,292
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At September 30, 2020, there were no indicators of impairment or impairment reversal. As a result, no impairment or impairment reversal testing was conducted.

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The calculation of depletion for the three and six months ended September 30, 2020 included $59.7 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2020 - $59.7 million).

8. TRADE AND OTHER PAYABLES

($000s)	September 30, 2020	March 31, 2020
Trade payables	357	417
Accrued liabilities and other payables	900	624
	1,257	1,041

9. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(2,160)
	12,210
Facility extension fees	(325)
Unrealized foreign exchange loss	4,274
Accretion	1,536
Balance, March 31, 2020	17,695
Unrealized foreign exchange gain	(975)
Accretion	123
Balance, September 30, 2020	16,843

($000s)	September 30, 2020	March 31, 2020
Current portion	16,843	17,695
Non-current portion	-	-

The Company initially entered into a US $25 million reserves based revolving credit facility (the "Credit Facility") in October 2014, placing an initial draw of US $14 million. The facility is secured by and available to the Company's producing assets in the Cuisinier field in Australia's Cooper Basin. On August 26, 2016, the Company repaid US $1.5 million.

On May 29, 2019, the Company and Westpac entered into an amendment to its reserves based revolving Credit Facility") that had 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. The Credit Facility requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. The interest rate under the Credit Facility remained unchanged at US LIBOR plus 3.75%.

On November 5, 2019, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to October 31, 2020. All previous terms and conditions remain the same except for the interest rate which moved from 3.75% to 3.95%.

On September 30, 2020, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to February 28, 2021. All previous terms and conditions remain the same except for the Credit Facility's reserve-based covenants have been waived including hedging requirements through February 28, 2021.

Management continues to discuss with the lender the opportunity to lengthen the term of the current facility particularly in light of the recent acquisition of the four PLs which has the potential to both increase reserves and improve cash flow. 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 table below indicates the current payment schedule for the Credit Facility:

(US$000s)	
Fiscal year 2021	12,369
	12,369

10. LEASE LIABILITY

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

($000s)	
Balance, March 31, 2020	204
Interest	6
Payments	(29)
Balance, September 30, 2020	181
Current portion of lease liability	(50)
Non-current portion of lease liability	131

11. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

$000s)	
Balance, April 1, 2019	1,977
Change in estimate	368
Additions	1,538
Accretion	34
Exchange adjustments	(227)
Balance, March 31, 2020	3,690
Accretion	9
Exchange adjustments	357
Balance, September 30, 2020	4,056

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 September 30, 2020 is approximately $4.0 million (March 31, 2020 - $4.0 million) which will be incurred between 2023 and 2054. An inflation factor of 1.73% (March 31, 2020 – 1.73%) and a risk-free discount rate of 0.77% (March 31, 2020 – 0.77%) have been applied to the decommissioning liability at September 30, 2020.

12. 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 at March 31, 2020 and September 30, 2020	102,266,694	98,100

13. 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 after the first year and one-third on each of the next two anniversary dates. The exercise price of each option equals the weighted average market price of the Company's common shares 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 over the first year. The remaining two instalments are charged to profit or loss over two and three years respectively.

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, 2020	3,472,500	0.12
Expired	(787,500)	0.18
Balance, September 30, 2020	2,685,000	0.10
Exercisable, September 30, 2020	2,593,334	0.10

14. REVENUE

Revenue from the sales of crude oil is based on the consideration specified in the Crude Oil Sales and Purchase Agreement ("COSP 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 COSP Agreement once the product is shipped to the end customer and lifted.

The transaction price as prescribed in the COSP 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 COSP 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.

15. PER SHARE AMOUNTS

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

	Three months ended September 30 2020	2019	Six months ended September 30 2020	2019
Net loss for the period ($000s)	(182)	(506)	218	(1,256)
Weighted average number of Common shares – basic and diluted (000s)	102,267	102,267	102,267	102,267
Basic and diluted loss per share	(0.00)	(0.00)	0.00	(0.01)

For the three and six months ended September 30, 2020, there were 2,685,000 (2019 – 3,502,000 and 1,882,492) options considered anti-dilutive.

16. FINANCE EXPENSE

($000s)	Three months ended September 30 2020	2019	Six months ended September 30 2020	2019
Interest income	-	-	-	(1)
Accretion on decommissioning and restoration liability	5	8	9	17
Interest on lease liability	3	3	6	7
Interest on credit facility	256	322	521	623
	264	333	536	646

17. 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 $18.3 million at September 30, 2020 (March 31, 2020 - $18.9 million). The current assets consist of accrued revenue in the form of pipeline oil and unallocated cash calls paid to the Joint venture operator in the amount of $1.4 million at September 30 2020.

At September 30, 2020, the Company had a working capital deficiency of $15.1 million, including cash and short-term deposits of $1.1 million and restricted cash of $0.04 million, compared to a working capital deficiency of $14.4 million at March 31, 2020. The working capital deficiencies are primarily a result of the Credit Facility of $16.8 million maturing in February 2021. The Company has no available undrawn debt capacity under its Credit Facility.

At September 30, 2020, the Company has significant capital spending commitments to be incurred by February 2021 on ATP 934P of $1.1 million and had its fully drawn US$12.4 million Credit Facility that matures in February 2021. In Q1 fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced to $1.1 million. In exchange for the reduction in commitment, the Company will relinquish 50% of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. The company is currently working with the Government of Queensland on amending the commitment requirements and is expecting a resolution by the end of February 2021.

On September 30, 2020, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to February 28, 2021. All previous terms and conditions remain the same except for the Credit Facility's reserve-based covenants have been waived including hedging requirements through February 28, 2021.

Management continues to discuss with Westpac the opportunity to lengthen the term of the Credit Facility particularly in light of the recent acquisition which has the potential to both increase reserves and improve cash flow. 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 majority of the Company's oil sales are benchmarked on US Brent prices. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of low crude prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts to reduce the impact of price volatility.

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

(US$000s)	
Credit Facility	
Fiscal year 2021	12,369

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 in Canadian dollar equivalent to foreign currencies for its financial instruments at September 30, 2020:

($000s)

	CAD$	**AUS$**	**US$**	**Total**
Cash and short-term deposits	171	7	877	1,055
Restricted cash	40	-	-	40
Trade and other receivables	10	107	1,299	1,416
Fair value of financial instruments	-	-	286	286
Trade and other payables	(238)	(1,017)	(2)	(1,257)
Credit facility	-	-	(16,843)	(16,843)
Lease liability	(181)	-	-	(181)
	(198)	(903)	(14,383)	(15,484)

Exchange rates as at:	September 30 2020	March 31 2020
Number of CAD$ for 1 AUS$	0.95	0.87
Number of CAD$ for 1 US$	1.34	1.42

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 September 30, 2020, the following derivative contracts were outstanding and recorded at estimated fair value:

Time period	Type of contract	Quantity Contracted	Price floor	Price ceiling	Fair value
		(bbls)	US $/bbl	US $/bbl	($000s)
October 1, 2020 – October 31, 2020	Oil - swap	4,200	59.27	59.27	100
November 1, 2020 – November 30, 2020	Oil - swap	4,200	58.95	58.95	95
December 1, 2020 – December 31, 2020	Oil - swap	4,200	58.63	58.63	91
Total					286

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US$12,600 (CAD$16,800) decrease in the fair value of financial instruments at September 30, 2020, while a US$1.00 decrease would result in an increase of approximately US$12,600 (CAD$16,800) in the fair value of the instruments.

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 September 30, 2020 as the funds are not invested in interest-bearing instruments. The Company's Credit Facility carries a floating interest rate based on quoted US LIBOR rates. The Company had no interest rate derivatives at September 30, 2020.

For the six months ended September 30, 2020, a 1% increase in US LIBOR would increase interest expense by $84,300.

18. SUPPLEMENTAL CASH FLOW INFORMATION

($000s)

Change in non-cash working capital items

	Three months ended September 30 2020	Three months ended September 30 2019	Six months ended September 30 2020	Six months ended September 30 2019
Trade and other receivables	4	(143)	223	430
Prepaid expenses and deposits	(99)	15	(98)	11
Trade and other payables	101	(250)	216	(869)
Effect of change in foreign exchange rates	8	(25)	70	(46)
	14	(403)	411	(474)
Attributable to:				
Operating	(99)	(197)	446	132
Investing	117	(216)	(31)	(616)
Financing	(4)	10	(4)	10
	14	(403)	411	(474)

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

($000s)

Cash interest paid and received

	Three months ended September 30 2020	Three months ended September 30 2019	Six months ended September 30 2020	Six months ended September 30 2019
Cash interest paid	175	223	408	466
Cash interest received	-	-	-	1

19. COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 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 up to three wells.

At September 30, 2020, 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 up to three wells	February 2021	1.1
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at September 30, 2020 at an exchange rate of AUS$1.00 = CAD$0.9541.

At September 30, 2020, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations October 2020 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	504	155	321	28	-
Decommissioning and restoration	4,056	-	707	70	3,279
	4,560	155	1,028	98	3,279

20. SEGMENTED INFORMATION

As at September 30, 2020, 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 six months ended September 30, 2020

	Australia	Corporate	Total
Revenue	2,359	-	2,359
Interest revenue	-	-	-
Interest expense	521	6	527
Depletion and depreciation	678	26	704
Impairment	-	-	-
Net income (loss)	578	(360)	218
Exploration and evaluation expenditures	-	-	-
Petroleum and natural gas property expenditures	223	-	223

($000s)

September 30, 2020

Exploration and evaluation assets	9,794	-	9,794
Petroleum and natural gas properties	28,153	-	28,153
Total assets	40,727	411	41,138
Total liabilities	21,918	419	22,337

($000s)

For the six months ended September 30, 2019

	Australia	Corporate	Total
Revenue	4,538	-	4,538
Interest revenue	1	-	1
Interest expense	623	7	630
Depletion and depreciation	781	28	809
Impairment	20	-	20
Net loss	(614)	(642)	(1,256)
Exploration and evaluation expenditures	10	-	10
Petroleum and natural gas property expenditures	1,747	-	1,747

($000s)

September 30, 2019

Exploration and evaluation assets	9,164	-	9,164
Petroleum and natural gas properties	27,375	-	27,375
Total assets	40,323	526	40,849
Total liabilities	21,373	416	21,789

($000s)			
For the three months ended September 30, 2020			
	Australia	**Corporate**	**Total**
Revenue	1,260	-	1,260
Interest revenue	-	-	-
Interest expense	256	3	259
Depletion and depreciation	342	14	356
Impairment	-	-	-
Net loss	(51)	(131)	(182)
Exploration and evaluation expenditures	-	-	-
Petroleum and natural gas property expenditures	124	-	124

($000s)			
For the three months ended September 30, 2019			
	Australia	**Corporate**	**Total**
Revenue	2,576	-	2,576
Interest revenue	-	-	-
Interest expense	322	3	325
Depletion and depreciation	441	14	455
Impairment	-	-	-
Net loss	(181)	(325)	(506)
Exploration and evaluation expenditures	-	-	-
Petroleum and natural gas property expenditures	477	-	477

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

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