Bengal
ENERGY LTD.

International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended
September 30, 2021 and 2020

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, 2021.

This MD&A dated November 4, 2021 should be read in conjunction with the Company's interim condensed consolidated financial statements and related notes for the quarter ended September 30, 2021. 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, 2021 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended September 30, 2021 may be referred to as "second quarter fiscal 2022", "Q2 fiscal 2022, "Q2 FY 2022", "current quarter", and "the quarter". The comparative three months ended September 30, 2020, may be referred to as "second quarter fiscal 2021", "Q2 fiscal 2021", and "prior year's quarter".

SECOND QUARTER FISCAL 2022 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $1.9 million in the second quarter fiscal 2022, which is 50% higher than the $1.3 million recorded in Q2 fiscal 2021 as decreased production was offset by increased commodity prices. Benchmark Brent price during the current quarter averaged US $76.48 per barrel of crude oil ("bbl") compared to US $46.18 per bbl for the same quarter in fiscal 2020.
- **Funds and Cash from Operations** – Bengal generated $0.6 million of cash from operating activities during Q2 fiscal 2022 compared to ($0.2) million of cash used in operations in Q2 fiscal 2021. Funds from operations were $0.4 million during fiscal Q2 2022 compared to funds used of ($0.1) million in Q2 fiscal 2021.
- **Net Loss** – Bengal reported a net income of $0.1 million for the current quarter compared to a net loss of $0.2 million in the second quarter fiscal 2021.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 18,303 bbls, which is a 14% decrease from the 21,247 bbls produced in the second quarter fiscal 2021. The current quarter production averaged 199 bbls/day compared to 231 bbls /day produced in the second quarter fiscal 2021. The decrease in production is a result of natural reservoir decline and absence of new drilling activity during the past 12 months.
- **Capital Expenditures** – Bengal incurred $0.6 million in capital expenditures during Q2 fiscal 2022 as compared to $0.1 million in Q2 fiscal 2021. The majority of the current quarter expenditures relate to site preparation and preliminary activities to support the Company's future development plans at its recently acquired 100% working interest Petroleum Leases ("PL"): PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline.

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, Petroleum Lease ("PL") 303 Cuisinier, ATP 934 Barrolka, ATP 732 Tookoonooka, 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, and under certain conditions relative to exploration success, 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. PCA applications include a commercial viability report that indicates that the area is likely to be commercially viable within the applied term. This allows for extra time to commercialize the resource. 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 holds four PLs including a pipeline license PPL 138 adjacent to the 100% owned ATP 934.

AUSTRALIA – Cooper Basin, Queensland

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

A pilot reservoir pressure maintenance scheme was initiated during the prior fiscal year. This pilot well encountered mechanical disruptions during initial attempts to commence water injection, which have been addressed through additional water filtration at the injection site. The joint venture expects to resume water injection activities during calendar Q4 2021. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier 24 well. The broad nature of the Cuisinier structure combined with variable flank aquifer pressure support has resulted in pressure depletion within the central portion of the Cuisinier pool. The injection of produced formation water is anticipated to both increase production in up to four offsetting wells and reduce water handling charges. On establishing success of the pilot, the Joint Venture will begin a multi phase water injection scheme, targeted fracture stimulation and more commercially efficient development drilling.

Bengal will participate in the 3D seismic controlled Chef exploration drilling project, which has been proposed by the Joint Venture operator (Santos) and is expected to commence in calendar Q4 2021. This target is in the northeast portion of the block which is immediately adjacent to the Cook and Cocinero fields also operated by Santos. This well will target the Jurassic age reservoirs of the Birkhead-Hutton formations which have proven to be prolific producers in the neighboring Cook and Cocinero fields.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned natural gas exploration block. In order to mitigate both financial and development risk, Bengal conducted extensive state-of-the-art geophysical work that has not been widely applied in Australia which gives a higher degree of confidence in the block and high grading prospects.

Bengal received special amendment approved for ATP 934 in March 2021 which relinquished 50% of the existing ATP area and extended the term of the ATP by entering into an outcome based Later Work Program (LWP) for another 6 years to February 28, 2027. The LWP includes the drilling of up to 3 wells and 260 km^2 of 3D seismic.

Bengal entered into an agreement with Santos in July of 2020 to farm-in on a portion of the ATP 934 block. This farm-out finances and de-risks the Company's initial field exploration by the basin leading gas explorer, with whom Bengal has an existing and successful partnership at the Cuisinier field. Additionally, and of equal importance, the partnership offers extensive operating experience backed by Santos' recent exploration success in neighboring fields analogous to the joint venture's exploration targets. Santos will carry the drilling costs of one well to earn a 60% operated interest in the ATP 934 southern farm-out block, which represents 57.8% of the total block post April 2020 relinquishment. On October 14, 2021 the Company's joint venture partner Santos completed the drilling of the Legbar-1 exploration well. Santos paid 100% of the costs to drill, plug and abandon the well and has accordingly earned a 60% working interest.

PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)

The Company is currently finalizing a schedule of development plans for its recently acquired 100% working interest in four PLs near to ATP 934. While not currently producing, all PLs have existing wells indicating log pay, drill stem test ("DST") results and or gas production from the Permian formation. Bengal has identified four wells to be tested and re-completed for production which may yield further follow-up development activities.

Specifically, this program is expected to include the following development activities; (a) recommissioning of a 26km pipeline to tie two previously producing Wareena liquids rich gas wells into a nearby compression station accessing the Eastern Australia local and export market; (b) subject to an appropriate commercial agreement with a crude oil buyer, work-over of the Ramses well that demonstrated both a Permian gas discovery and oil-zone completion in a cased well, which recovered 588 bbls/d of light crude oil, based on a 105-minute drill stem test; (c) work-over of the Ghina well to evaluate the previous Permian liquids rich gas discovery and assess the economics of tie-in and field recovery; and finally (d) twin drilling of the existing Karnak well that showed a liquids rich gas pay zone in the Permian formation. Bengal expects that with the application of advanced underbalanced drilling techniques now commonplace in the Cooper Basin, a successful new well could be immediately tied into nearby gathering infrastructure.

The 100% ownership of these assets presents an appraisal and development opportunity that will be operated by the Company and is seen not only to be complementary to our 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 upon which future exploration growth through ATP 934 can be undertaken.

ATP 732 Tookoonooka (100% WI)

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.

The Company is currently evaluating the opportunity to fracture stimulate the Caracal-1 well, a 53 API oil discovery in the Wyandra zone. Following stimulation, the well could commence production using the Company's Early Oil Production System with the addition of storage and load-out infrastructure.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback amounts)		Three months ended September 30 2021		2020		Six months ended September 30 2021		2020
Oil revenue	$	1,884	$	1,260	$	3,431	$	2,359
Operating netback[(1)]	$	935	$	577	$	1,595	$	1,260
Cash flow from (used in) operations	$	565	$	(166)	$	(209)	$	169
Funds from (used in) operations[(2)]	$	417	$	(67)	$	536	$	(277)
Per share ($) (basic and diluted)	$	0.00	$	(0.00)	$	0.00	$	(0.00)
Net income (loss)	$	85	$	(182)	$	(97)	$	218
Per share ($) (basic and diluted)	$	0.00	$	(0.00)	$	(0.00)	$	0.00
Capital expenditures	$	649	$	124	$	786	$	223
Oil volumes (bbls/d)		199		231		187		234
Operating netback[(1)]($/bbl)	$	51.08	$	27.15	$	46.53	$	29.39

(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.

(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 income (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 14.

RESULTS OF OPERATIONS

Production	Three months ended September 30 2021	2020	Six months ended September 30 2021	2020
Oil production (bbls/d)	199	231	187	234
Oil production (bbls)	18,303	21,247	34,284	42,864

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	
		2021	**2020**	**2021**	**2020**
	Oil lifting				
	Volume (000s bbls)	19.9	22.5	34.9	45.8
	Weighted average price (US$/bbl)	76.48	46.18	73.38	33.54
A.	Sales ($000's)	1,933	1,683	3,263	2,314
	Pipeline oil				
	Volume (000s bbls), change	(1.6)	(5.6)	(0.6)	(2.4)
	Price (US$/bbl), change	9.79	(0.55)	19.72	15.42
B.	Net sales ($000's)	(49)	(423)	168	45
A.+B.	Total oil sales ($000s)	1,884	1,260	3,431	2,359

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 prices during the current quarter increased by 74% compared to the previous year's quarter based on increased benchmark Brent pricing. The realized weighted average price of oil lifting sales was US $76.48/bbl for the current quarter compared to US $46.18/bbl. This increase in pricing was partially offset by a 15% decrease in production.

During the current quarter, the value of pipeline oil decreased by $49,000 as a 1,600 bbl decrease was partially offset by a US $9.79/bbl increase in pricing. After adjusting for changes in pipeline oil, sales for the current quarter are $1.9 million, which is a 50% increase from the $1.3 million recorded during the prior year's quarter.

The following table outlines average benchmark prices:

	Three months ended September 30		Six months ended September 30	
	2021	**2020**	**2021**	**2020**
Brent oil ($/bbl)	92.57	57.14	88.23	49.16
Brent oil (US$/bbl)	73.47	42.96	71.15	36.15
Number of CAD$ for 1 AUS$	0.93	0.95	0.94	0.93
Number of CAD$ for 1 US$	1.26	1.33	1.24	1.36

($000s)

Operating netbacks

	Three months ended September 30		Six months ended September 30	
	2021	**2020**	**2021**	**2020**
Oil sales	1,884	1,260	3,431	2,359
Realized gain on financial instruments	-	261	-	806
Royalties	113	76	206	142
Operating expenses	836	868	1,630	1,763
Operating netback	935	577	1,595	1,260
($/bbl)				
Oil sales	102.93	59.30	100.08	55.03
Realized gain on financial instruments	-	12.28	-	18.80
Royalties	6.17	(3.58)	6.01	(3.31)
Operating expenses	45.68	(40.85)	47.54	(41.13)
Operating netback	51.08	27.15	46.53	29.39

Operating netbacks in Q2 fiscal 2022 were $0.9 million or $51.08/bbl compared to Q2 fiscal 2021 at $0.6 million or $27.15/bbl. For the six months ended Q2 fiscal 2022, operating netback was $1.6 million or $46.93/bbl. This compares to $1.3 million or $29.39/bbl for the six months ended Q2 fiscal 2021. The primary reason for the higher operating netbacks per barrel during the current quarter compared to Q2 fiscal 2021 was the realization of a higher dollar per barrel on oil sales. During the current quarter, Bengal realized an average of $102.93/bbl as compared to $59.30/bbl on oil sales revenue for Q2 fiscal 2021.

Royalties

Royalties

	Three months ended September 30		Six months ended September 30	
	2021	**2020**	**2021**	**2020**
Royalty expense ($000s)	113	76	206	142
$/bbl	6.17	3.58	6.01	3.31
% of revenue	6	6	6	6

In Queensland Australia, oil royalties are based on a government-established rate which scales according to benchmark oil prices plus a Native Title royalty of 1%.

Royalty rates approximate 6% of oil sales for Q1 fiscal 2022 consistent with Q1 fiscal 2021.

Operating Expenses

($000s) Operating expenses	Three months ended September 30		Six months ended September 30	
	2021	2020	2021	2020
Production	252	195	546	378
Transportation	584	673	1,084	1,385
	836	868	1,630	1,763
Production - $/bbl	13.77	9.18	15.93	8.82
Transportation - $/bbl	31.91	31.68	31.62	32.30
	45.68	40.86	47.55	41.12

Total operating expense during the second quarter fiscal 2022 was $0.8 million or $45.68/bbl. This compares to $0.9 million of operating expenses for the second quarter fiscal 2021 or $40.86/bbl. Operating expenses per barrel were higher in the current quarter due to decreased production relative to fixed operating expenses.

General and Administrative (G&A) Expenses

($000s) G&A Expenses	Three months ended September 30		Six months ended September 30	
	2021	2020	2021	2020
Total G&A expenses	545	540	1,131	1,046
Capitalized G&A expenses	(28)	-	(79)	(7)
Net G&A expenses	517	540	1,052	1,039

Total G&A expense for Q2 fiscal 2022 was $0.5 million as compared to $0.5 million for Q2 fiscal 2021. The consistent G&A expense result from the significant cost reduction programs implemented by management over the past 12 months.

Share-based Compensation (“SBC”)

($000s) SBC	Three months ended September 30		Six months ended September 30	
	2021	2020	2021	2020
Expensed share-based compensation	32	-	62	5
Capitalized share-based compensation	1	-	3	-
	33	-	65	5

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. 11,340,000 stock options were issued on March 22, 2021, however these options only vest one-third on the first, second and third year following the grant. As a result of this vesting schedule, there is no significant share-based compensation expense related to these option grants during the current quarter. There were no stock options granted during the current quarter.

Depletion and Depreciation (DD&A)

($000s) DD&A	Three months ended September 30 2021	 2020	Six months ended September 30 2021	 2020
Petroleum and natural gas ("PNG") properties	283	343	536	677
Other assets	1	1	2	3
Right-of-use assets	7	12	15	24
	291	356	553	704
Depletion - PNG properties - $/bbl	15.46	16.14	15.63	15.79

Production in Q2 fiscal 2022 was 18,303 bbls compared with 21,247 bbls in Q2 fiscal 2021. The lower production in Q2 fiscal 2022 when compared to Q2 fiscal 2021 resulted in the lower depletion expense. The depletable costs base is slightly lower during the current quarter, resulting in a lower DD&A per bbl when compared to Q2 fiscal 2021.

Finance Expense

($000s) Finance expense	Three months ended September 30 2021	 2020	Six months ended September 30 2021	 2020
Accretion expense on decommissioning and restoration liability	8	5	16	9
Interest on lease liability	2	3	3	6
Interest on credit facility	-	256	-	521
Interest – other	4	-	4	-
	14	264	23	536

Following the settlement of the Company's Westpac debt facility during Q4 fiscal 2021 there was no outstanding credit facility.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended September 30		Six months ended September 30	
	2021	2020	2021	2020
Geological and geophysical	512	42	570	99
Drilling	4	-	4	12
Completions	133	82	212	112
	649	124	786	223
Exploration and evaluation expenditures	17	-	10	-
Development and production expenditures	632	124	776	223
	649	124	786	223

Bengal incurred $0.6 million in capital expenditures during Q2 fiscal 2022 as compared to $0.1 million in Q2 fiscal 2021. The majority of the current quarter expenditures relate to site preparation and preliminary activities to support the Company's future development plans at its recently acquired 100% working interest Petroleum Leases ("PL"): PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline.

SHARE CAPITAL

Trading history	Three months ended September 30		Six months ended September 30	
	2021	2020	2021	2020
High ($)	0.14	0.06	0.14	0.06
Low ($)	0.08	0.03	0.07	0.02
Close ($)	0.09	0.04	0.09	0.04
Volume (000s)	1,415	2,470	5,396	6,146
Shares outstanding (000s)	432,987	102,267	432,987	102,267
Weighted average shares outstanding (000s)				
- basic	432,987	102,267	432,987	102,267
- diluted	435,255	102,267	432,987	102,267

At November 4, 2021, there were 432,986,694 common shares issued and outstanding, together with 13,475,000 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 financial liabilities consist of trade and other payables and lease liability and amounted to $1.8 million at September 30, 2021 (March 31, 2021 - $2.0 million).

At September 30, 2021, the Company had working capital, comprised of current assets less current liabilities, of $4.0 million, including cash and short-term deposits of $3.8 million and restricted cash of $0.04 million, compared to working capital of $4.3 million at March 31, 2021.

Management anticipates that operating and capital requirements will be met out of working capital and operating cash flows.

During fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced in exchange for a 50% relinquishment of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. Current commitments are $8.2 million over the next six years.

In February 2021, the Company raised $16.54 million on the issuance of common shares and extinguished the credit facility. Management anticipates that operating and capital requirements will be met out of working capital and operating cash flows.

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 on lower risk projects with near-term cash flow upside.

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 ATP 934 work program consists of 260 km^2 of 3D seismic and up to three wells.

At September 30, 2021, 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 2027	8.2
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, 2021 at an exchange rate of AUS$1.00 = CAD$0.9164.

(2) During fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced in exchange for a 50% relinquishment of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. During Q2 fiscal 2021, the Company entered into a farm-in agreement with Santos whereby Santos will pay 100% of the well costs of a one well work program with an estimated cost of AUS$2.7 million planned for the second half of calendar 2021. The $8.2 million of estimated expenditures is net of the estimated carried cost of AUS$2.7 million.

At September 30, 2021, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations October 2021 to March 2057	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	232	101	131	-	-
Decommissioning and restoration	3,343	-	708	58	2,577
	3,575	101	839	58	2,577

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Sep 30 2021 Q2 2022	Jun 30 2021 Q1 2022	Mar 31 2021 Q4 2021	Dec 31 2020 Q3 2021	Sep 30 2020 Q2 2021	June 30 2020 Q1 2021	Mar 31 2020 Q4 2020	Dec 31 2019 Q3 2020
Oil sales	1,884	1,547	1,601	1,274	1,260	1,099	1,140	2,425
Cash flow from (used in) operations	565	(774)	70	62	(166)	335	27	259
Funds from (used in) operations[(1)]	417	119	(158)	130	(67)	(210)	(849)	599
Per share – basic and diluted ($)	0.00	0.00	(0.00)	0.00	(0.00)	(0.00)	(0.01)	0.01
Net income (loss)	85	(182)	3,040	670	(182)	400	(2,196)	556
Per share – basic and diluted ($)	0.00	(0.00)	0.01	0.01	(0.00)	0.00	(0.02)	0.01
Capital expenditures	649	137	533	498	124	99	(68)	346
Working capital (deficiency)	3,961	4,218	4,270	(15,068)	(15,129)	(14,908)	(14,434)	(13,823)
Total assets	42,321	42,429	44,246	41,914	41,138	41,097	39,572	41,391
Shares outstanding (000s)	432,987	432,987	432,987	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	199	176	202	211	231	238	254	280
Operating netback[(1)] ($/bbl)	51.08	41.30	36.77	42.37	27.15	31.60	10.77	59.68

(1) See "Non-IFRS Measurements" on page 14 of this MD&A.

Oil sales and production over the last eight quarters peaked during the third quarter of fiscal 2020 (calendar Q4 2019). Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since the peak. Significant volatility in US Brent prices during the past eight quarters resulted in volatile oil sales and funds from operations. Oil prices have stabilized over the past two quarters. 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 from Q3 fiscal 2020 through Q4 fiscal 2021 was materially impacted by the impact of US/CAD exchange rates to the Company's US dollar Westpac Credit facility as well as the impact of gains and losses on derivative financial instruments. After the repayment of debt and cancellation of all derivative instruments in Q4 fiscal 2021, net income is less subject to foreign exchange and commodity price volatility. 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 fiscal

2021. Settlement of the Company’s debt facility restored the Company’s working capital position as of Q4 Fiscal 2021.

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, 2021 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 2021 annual Management’s Discussion and Analysis dated June 17, 2021.

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, 2021.

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**		**Six months ended September 30**	
	2021	**2020**	**2021**	**2020**
Cash from (used in) operating activities	565	(166)	(209)	169
Changes in non-cash working capital	(148)	99	745	(446)
Funds from (used in) operations	417	(67)	536	(277)

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**		**Six months ended September 30**	
	2021	**2020**	**2021**	**2020**
Net income (loss)	85	(182)	(97)	218
Unrealized loss on financial instruments	-	303	-	1,254
Unrealized foreign exchange gain	-	(638)	-	(2,596)
Adjusted net income (loss)	85	(517)	(97)	(1,124)

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 more complete list of risk factors is provided in Bengal's Annual Information Form dated June 29, 2021 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 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. Additionally, such actions have resulted in volatility and disruptions in regular business operations, supply chains and financial markets.

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 1110, 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" ("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;*
- *Bengal's drilling program and waterflood pilot;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *Timing and re-assessment of restarting the planning and drilling selection for the 2021 multi-well development and appraisal drilling campaign:*
- *The timing of the planned injection of produced formation water on the Barta Block PL 303 and the anticipated resulting production increases, future waterflood expansion phases, and reduced operating costs;*
- *The timing of equipping for production cased wells;*
- *The continued engagement in early stage discussions with third parties with respect to potential business combination transactions;*
- *The continued integration of subsurface data from production licenses in the selection of exploration and appraisal drilling locations;*
- *The future development prospects generated by the initial development activities at PL 1110 (previously 114) Wareena, PL 1109 (previously 157) Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline.*
- *Projections of market prices and costs including, but not limited to, expected royalty rates;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *That required payments will be met out of operation cash flows and alternative forms of financing;*
- *Bengal's ability to finance its working capital deficiency and to source funds for the same;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs; and*
- *That funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures, share issuances or other alternative forms of capital raising and funds will be sufficient to meet requirements including but not limited to Bengal's exploration activities through fiscal 2022 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;*
- *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, 2021 (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.

This document discloses unbooked drilling locations. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per area based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

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.

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
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WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT Computershare • Toronto, Canada

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

DISCLOSURE COMMITTEE
Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE
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Robert D. Steele
W. B. (Bill) Wheeler

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Peter Lansom
Bob Steele

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Robert D. Steele
Dr. Brian J. Moss

OFFICERS
Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Jerrad Blanchard, Chief Financial Officer
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG