Bengal
ENERGY LTD.

INTERNATIONAL EXPLORATION & PRODUCTION

2022 Annual Report
Twelve Months Ended
March 31, 2022

BENGAL ENERGY LTD

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

This past year, we have continued to witness a remarkable turnaround for the global upstream energy industry as economies recovered from the Covid-19 pandemic and oil and gas prices surged. During fiscal 2022, Bengal Energy Ltd. ("Bengal" or the "Company") benefited from this recovery in crude oil prices. With zero debt, our free cash flow from operations continues to be deployed to our operated projects in the Cooper Basin, and we are entirely committed to generating value for shareholders.

The near-term outlook for crude oil and natural gas prices in the Australian market has strengthened because of geo-political conflicts impacting supply and a resumption to more normal demand levels as the impact of the COVID 19 pandemic diminishes. We are now encouraged by the medium-term bullish outlook for natural gas demand for eastern Australia and optimistic about the multiple egress and marketing opportunities available to optimize returns on the Company's natural gas-rich asset. At the time of writing, both oil and natural gas prices are at robust levels with Brent oil being priced on the spot market at US$110-120 per barrel and east coast Australia spot gas prices of Australian$40 per gigajoule.

Production for the fiscal year ended March 31, 2022, averaged 183 barrels of oil per day, at which level, we generate $3.5 million of free cash flow on an annualized basis at Brent oil price of US$ 100/barrel. Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2022, are 5,778 thousand barrels of oil ("Mbbls"), and Proved ("1P") reserves are 2,145 Mbbls compared to 5,789 Mbbls and 2,163 Mbbls for 2P and 1P reserves respectively at March 31, 2021. The net present value (NPV10, before tax) of Bengal's 2P reserves, net of future development costs, at March 31, 2022, is $149.0 million, or $0.30 per share compared to $87.6 million at March 31, 2021. The 2P after-tax net asset value is $115 million for the current year compared to $69.2 million in the prior year.

The Company commissioned a third-party Resource Assessment effective March 20, 2022; this is distinct from and incremental to the Company's March 31, 2022, Year-end Reserves Report. Results indicate Best Estimate Contingent Resources of 1.1 million barrels of light crude oil and 19 billion cubic feet of natural gas for a total Barrel of Oil Equivalent of 4.3 million. Prospective Resources Best Estimate is 10.6 million barrels of light crude oil and 29.3 billion cubic feet of natural gas for a total of 15.5 million barrels of oil equivalent.

Our goal is to consistently add value per share by capitalizing on the significant inventory of development, appraisal, and exploration opportunities that we have added to our portfolio over the last five years, which is quantified by our third-party Reserves and Resources evaluations. The initial work program on the 100%-owned Wareena and Caracal projects was started in Calendar Q1 2022, faced several weather-related interruptions to road and lease access, and we now expect results in Q3 of this year. In Q1, 2022, Bengal was able to access additional funding through a Private Placement raising $4.2 million through the issuance of 52.3 million shares, with participation in this funding of both Canadian and Australian investors and insiders. This funding and our free cash flow are being deployed towards the Wareena and Caracal work programs.

Included in the Wareena project is the reinstatement of two gas wells (Wareena-1 and Wareena-5) and an existing gas pipeline to produce raw gas into the existing transportation infrastructure. With deeper zone water shut off on Wareena-5, the next activity will be to achieve the same on Wareena-1, followed by flowback tests to determine initial natural gas productive capabilities for the two wells. Negotiations regarding natural gas processing and sales are ongoing with Santos as the owner of the transportation and processing infrastructure. The company is evaluating multiple options for commercialization of expected natural gas production, including connection through a third-party gathering system with existing processing infrastructure, as well as an innovative proof of concept for alternative monetization. The Caracal-1 well, a 53 API oil discovery on ATP 732, was re-entered and produced oil to the surface. While this well is currently being assessed to determine capacity for improved commercial production, the Company has secured an offtake agreement for this oil with the nearby Inland Oil Refinery, and in parallel is moving forward with a longer-term lease retention application for this prospective block with multiple egress options for its crude oil resources.

Considerable progress has been made by the Company with the deployment of both our Early Oil Production System (EOPS) and our Early Gas Production System (EGPS). The EOPS will be field-tested during the current quarter and the EGPS is expected to be onsite and operating by August. We have received strong expressions of interest from other operators in Queensland and South Australia about the availability of these systems on a contract basis. As we mature these opportunities, we expect to announce updates outlining expected benefits to all shareholders from these technologies developed by the Company.

In Bengal's non-operated Cuisinier oilfield, a pilot reservoir pressure maintenance scheme was initiated during the prior fiscal year in the southeast quadrant of the pool, with the injection of water taking 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. The Cuisinier water injection pilot has continued to face a range of surface facility-related operational issues resulting in downtime, which have not allowed the significant subsurface success potential of this pilot to be realized yet. Bengal Energy personnel are now working collaboratively with the Operator's Onshore Operations and Development Leadership towards rectifying the surface facility operational challenges. Currently, the water injection rate into C24 is approximately 300 bpd at a wellhead pressure of 9,600 Kilopascal (1392 psi). Nearby wells are being monitored for total fluid produced and water cut to help to determine which wells are affected by the pilot program. Upon establishing success of the pilot, the Joint Venture ("JV") expects to begin a multi-phase water injection scheme, targeted fracture stimulation and more commercially efficient development drilling. Since inception of the pilot, 33,500 barrels of water have been injected into the C24 well at an average rate of approximately 275 barrels of water per day over 115 operating days since December 2021.

During Q2 and Q3 of this year, we are focused on converting near term cash generating opportunities at the Wareena and Caracal fields. Our next phase of development is aimed at unlocking currently stranded gas assets at Ramses, Ghina and Nubba and finalizing the reinstatement of the Wareena to Coonaberry pipeline. The stranded gas assets are developed on the back of the field trial of our EGPS. One of the Ramses well has a Jurassic oil resource which we are planning to access with a dual packer and sliding side sleeve completion. We are currently working at determining export routes for this high pour point light oil. A more challenging appraisal will be worked through at Karnak where the current well bore has significant washouts. The plan is to either sidetrack or drill a new well in a more crestal position to access the gas resource associated with this well. In parallel, we expect to see new development and appraisal drilling activity on our Cuisinier asset, consistent performance of the Cuisinier Water Flood Pilot and are working on Joint Venture participation in exploration drilling on ATP 732 as well as developing new opportunities for Permian Gas drilling on ATP 934. This year's activities are targeted at creating a stable and flexible production and cash flow platform from which to drive sustainable growth and we are excited for the opportunity to deliver on this promise through a balanced mix of development, appraisal, and exploration projects during the coming year.

Our success will continue to be driven by our dedicated and talented team of employees who are passionate about delivering our strategies and plans to create value for shareholders. Complementing our team, our Board of Directors is an indispensable source of guidance and day-to-day support which we rely on as we drive forward towards our value-creation objectives to benefit all shareholders. We look forward to executing our plans in the months ahead for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,

(signed) "Chayan Chakrabarty"

Chayan Chakrabarty
President & CEO

Note: this Message to Shareholders contains forward-looking statements and is subject to the forward-looking statement disclaimer in the Management's Discussion & Analysis for the Years Ended March 31, 2022, and 2021

INTERNATIONAL EXPLORATION & PRODUCTION

Management's Discussion & Analysis

Three and Twelve Months Ended March 31, 2022 and 2021

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 and twelve months ended March 31, 2022.

This MD&A dated June 15, 2022 should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2022 and 2021. The consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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 and Other Financial Measures, abbreviations and forward-looking information relating to future events and the Company's future performance. Please refer to "Non-IFRS and Other Financial Measures s", "Abbreviations" and "Advisories" sections at the end of this MD&A for further information. These do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting standards Board and therefore may not be comparable with the calculation of similar financial measures disclosed by other entities.

Additional information relating to Bengal, including Bengal's audited March 31, 2022 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended March 31, 2022 may be referred to as "fourth quarter of fiscal 2022", "Q4 fiscal 2022", "Q4 FY 2022", "current quarter", and "the quarter". The comparative three months ended March 31, 2021, may be referred to as "fourth quarter of fiscal 2021", "Q4 fiscal 2021" "Q4 FY 2021", and "prior year's quarter". The year ended March 31, 2022, may be referred to as "fiscal 2022", "current year", and "the year". The comparative year ended March 31, 2021, may be referred to as "the previous year", "prior year", and "fiscal 2021".

FOURTH QUARTER FISCAL 2022 SUMMARY

Financial Summary:

- **Reserves –**Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2022 are 5,778 thousand barrels of oil ("Mbbls") and Proved ("1P") reserves are 2,145 Mbbls compared to 5,789 Mbbls and 2,163 Mbbls for 2P and 1P reserves respectively at March 31, 2021. The net present value (NPV_{10}, before tax) of Bengal's 2P reserves, net of future development costs, at March 31, 2022 is $149.0 million, or $0.30 per share compared to $87.6 million at March 31, 2021. The 2P after tax net asset value is $115 million for the current year compared to $69.2 million in the prior year.
- **Sales revenue** – Crude oil sales revenue was $2.4 million in the fourth quarter of fiscal 2022, which is 50% higher than the $1.6 million recorded in Q4 fiscal 2021. Full year fiscal 2022 sales revenue was $7.7 million compared to $5.2 million for the full year fiscal 2021.
- **Funds from (used in) operations**[1] – Bengal generated $0.5 million of funds from operations during Q4 fiscal 2022 compared to a $0.2 million funds used in operations during Q4 fiscal 2021. For the full year fiscal 2022, the Company generated $1.4 million of funds from operations compared to $0.3 million funds used in operations during the prior fiscal year.
- **Net income** – Bengal reported net income of $0.2 million for the current quarter compared to net income of $3.9 million in the fourth quarter of fiscal 2021. For the full year fiscal 2022, the Company reported a net loss of $0.4 million compared net income of $3.9 million in the prior year. Several non-operational items contributed to net income during the prior year that were absent in the current

[1] See "Non-IFRS and Other Financial Measures" on page 16 of this MD&A

period, including $3.7 million of foreign exchange gains and a $3.5 million gain on the settlement of the Company's Credit Facility.

- **Private placement** – On March 7, 2022 the Company closed a private placement to issue 52.3 million shares for $4.2 million of proceeds.

Operational Summary:

- **Production volumes** – The Company's share of total production in the current quarter was 15,647 bbls of light crude oil, which is a 14% decline from the 18,222 bbls produced in the fourth quarter of fiscal 2021. The current quarter production averaged 174 bbls/day compared to 202 bbls/day produced in the fourth quarter of fiscal 2021. Full year fiscal 2022 saw total production of 66,797 bbls compared to 80,530 bbls for full year fiscal 2021. The full year fiscal 2022 production per day averaged 183 bbls compared to 221 bbls/day for the full year fiscal 2021.
- **Capital expenditures** – During the year, the Company commenced capital programs on two of its 100% owned and operated projects at Wareena (Petroleum Lease ("PL") 1110 & Producing Pipeline ("PPL") 138) and Caracal (Authority to Prospect ("ATP") 732). Bengal incurred $2.2 million in capital expenditures during Q4 fiscal 2022 as compared to $0.5 million in Q4 fiscal 2021 and a total of $4.3 million during the current year compared to $1.2 million during fiscal 2021. Work in these projects is currently ongoing.

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, PL 303 Cuisinier, ATP 934 Barrolka, ATP 732 Tookoonooka, and four petroleum licenses acquired in calendar 2019 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 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 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 (PL 114 Wareena, PL 157 Ghina, PL 188 Ramses, PL 411 Karnak) including a pipeline license PPL 138 adjacent to ATP 934.

<u>AUSTRALIA – Cooper Basin, Queensland</u>

PL303 and PL 1028 Cuisinier (controlling permit ATP 752) (30.357% WI)

A pilot reservoir pressure maintenance scheme was initiated during the prior fiscal year and after resolving mechanical issues, water injection activities resumed during calendar Q4 2021. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water taking 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. The Cuisinier water injection pilot has continued to face a range of surface facility-related operational issues resulting in downtimes, which have not allowed the significant subsurface success potential of this pilot to be realized as yet. Bengal Energy personnel are now working with the Operator's Onshore Operations and Development Leadership to work collaboratively towards rectifying the surface facility design challenges.

Upon establishing success of the pilot, the Joint Venture ("JV") expects to begin a multi-phase water injection scheme, targeted fracture stimulation and more commercially efficient development drilling. Since inception of the pilot, 33,500 barrels of water have been injected into the C24 well at an average rate of approximately 275 barrels of water per day over 115 operating days since December 2021. Currently, the water injection rate into C24 is approximately 300 bpd at a wellhead pressure of 9,600 Kilopascal. Nearby wells are being monitored for total fluid produced and water cut to help to determine which wells are being affected by the pilot program.

In December 2021, Bengal participated in the Chef exploration drilling project. Following a review of the well logs, the ATP 752 JV parties have decided to plug and abandon the well. This exploration well is located outside of the producing Cuisinier field PL 303, in a location 4 km to the northeast with primary targets in the Jurassic Birkhead Formation and Hutton Sandstone, and secondary targets within the Triassic Nappamerri Group. The well encountered multiple oil shows in the primary and secondary targets; however, no commercial pay was identified at this location. While not a commercial success, the identified oil shows may support continued exploration targeting both the Jurassic Birkhead and newly discovered oil-bearing Triassic Nappamerri formations.

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

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. 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 the reinstatement of two gas wells (Wareena-1 and Wareena-5) and an existing gas pipeline to produce raw gas into existing infrastructure. Planning and execution of the project continued through Q4 fiscal 2022 including performing a deeper zone water shut off on Wareena-5. Negotiations regarding natural gas processing and sales are ongoing with Santos as the owner of the processing infrastructure. The company is evaluating various options for commercialization for expected natural gas production, including connection through existing processing infrastructure and an innovative proof of concept for alternative monetization.

The 100% ownership of the acquired Assets presents an appraisal and development opportunity that will be operated by the Company and is seen to be not only complementary to our proven producing, non-operated Cuisinier asset, but also as a key steppingstone for Bengal's natural gas platform upon which future exploration growth through ATP 934 can be undertaken.

ATP 732 Tookoonooka (100% WI)

The Company has conducted preliminary workover and stimulation program at the Caracal-1 well, a 53 API oil discovery in the Wyandra zone. The well produced oil to the surface, although at lower-than-expected rates and is currently being assessed to determine capacity for commercial production. This would allow the Company to progress towards a PL or PCA on the block.

In June 2019, the Company applied for an amendment to the LWP ("Later Work Program") 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 $0.05 million and geological and geophysical investigation at an estimated cost of $0.05 million during the four-year term.

ATP 934 Durham Downs East Farmout Block (40% WI)

Bengal entered into an agreement with Santos in July of 2020 to farm-in on a portion of the ATP 934 block. Santos carried 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 acreage post April 2020 relinquishment. On October 14, 2021, 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 in 103,760 km^2 gross exploration land.

While the Legbar-1 Well did not indicate commercial quantities of hydrocarbons, thick, high quality reservoir sands were encountered in the primary Permian Toolachee formation and in the Jurassic Birkhead zone, with evidence of residual hydrocarbon saturation in both zones. In addition, fluorescence shows and elevated gas readings through the Jurassic Birkhead Fm/Top Hutton Sandstone indicate oil has passed through the reservoir, supporting the search for a valid closure to test this play. The findings from the Legbar-1 well will help Bengal refine its exploration targets going forward, both with Santos in the Santos Farm-out Block, and across the balance of ATP 934 which is 100% owned by Bengal.

Business Development

The Company is in discussions with potential industry and financial partners to fund some of these oil and gas-related activities.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback amounts)		Three months ended March 31				Twelve months ended March 31		
		2022		2021		2022		2021
Oil revenue	$	2,374	$	1,601	$	7,650	$	4,822
Operating netback[1]	$	1,425	$	670	$	4,109	$	2,754
Cash from operations	$	437	$	70	$	835	$	301
Funds from (used in) operations[1]	$	515	$	(158)	$	1,432	$	(305)
Per share ($) (basic and diluted)	$	0.00	$	0.00	$	0.00	$	0.00
Net income (loss)	$	217	$	3,040	$	(374)	$	3,928
Per share ($) (basic and diluted)	$	0.00	$	0.01	$	(0.00)	$	0.03
Capital expenditures	$	2,244	$	533	$	4,322	$	1,254
Oil volumes (bbl/d)		174		202		183		221
Operating netback [1]($/bbl)	$	91.06	$	36.67	$	61.52	$	34.20

(1) Non-IFRS and Other Financial Measures

RESULTS OF OPERATIONS

Production

	Three months ended March 31 2022	Three months ended March 31 2021	Twelve months ended March 31 2022	Twelve months ended March 31 2021
Oil production (bbls/d)	174	202	183	221
Oil production (bbls)	15,647	18,222	66,797	80,530

Production during Q4 fiscal 2022 decreased 14% compared the Q4 fiscal 2021 and total current fiscal year production decreased 17% compared to the fiscal 2021. These decreases represent natural production declines at the Cuisinier field. During fiscal 2022, the only capital activity incurred in the field related to the water injection pilot program, which is currently injecting water at a rate of 300 bbls per day. To date there is insufficient data to determine the impact of water injection on the reservoir and oil production.

Revenue/Pricing

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

		Three months ended March 31 2022	Three months ended March 31 2021	Twelve months ended March 31 2022	Twelve months ended March 31 2021
	Oil lifting				
	Volume (000s bbls)	14.0	17.0	67.3	85.7
	Weighted average price ($US/bbl)	107.36	63.88	83.66	43.26
A.	Sales (CDN $000's)	1,864	1,390	7,131	5,028
	Pipeline oil				
	Volume (000s bbls), change	1.6	1.2	(0.5)	(4.7)
	Price ($US/bbl), change	30.20	9.90	50.63	(39.56)
B.	Net sales (CDN $000's)	510	211	519	206
A.+B.	Total oil sales (CDN $000s)	2,374	1,601	7,650	5,234

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 68% compared to the previous year's quarter based on increased benchmark Brent pricing. The realized weighted average price of oil lifting sales was US $107.36/bbl for the current quarter compared to US $63.88/bbl during Q4 fiscal 2021. This increase in pricing was partially offset by a 14% decrease in production.

During the current quarter, the higher pipeline oil amount was due to both an increase in price of US $30.20/bbl and a 400 bbl volume increase. After adjusting for changes in pipeline oil, sales for the current quarter are $1.9 million, which is a 34% increase from the $1.4 million recorded during the prior year's quarter.

The following table outlines average benchmark prices:

	Three months ended March 31 2022	2021	Twelve months ended March 31 2022	2021
Brent oil ($/bbl)	127.38	77.85	100.69	58.99
Brent oil (US$/bbl)	100.30	60.82	80.55	44.35
Number of CAD$ for 1 AUS$	0.92	0.99	0.93	0.95
Number of CAD$ for 1 US$	1.27	1.28	1.25	1.33

($000s)

Operating netbacks[1]

	Three months ended March 31 2022	2021	Twelve months ended March 31 2022	2021
Oil sales	2,374	1,601	7,650	5,234
Realized gain on financial instruments	-	-	-	1,033
Royalties	(142)	(96)	(459)	(314)
Operating expenses	(807)	(835)	(3,082)	(3,199)
Operating netback	1,425	670	4,109	2,754
($/bbl)				
Oil sales	151.72	87.86	114.53	64.99
Realized gain on financial instruments	-	-	-	12.83
Royalties	(9.08)	(5.27)	(6.87)	(3.90)
Operating expenses	(51.58)	(45.92)	(46.14)	(39.72)
Operating netback	91.06	36.67	61.52	34.20

(2) See Non-IFRS and Other Financial Measures

In Q4 fiscal 2022, operating netbacks were $1.4 million or $91.06/bbl compared to Q4 fiscal 2021 at $0.7 million or $36.67/bbl. The primary reason for the 113% increase in operating netbacks is improved realized pricing on crude oil sales, which more than offset production declines. For the full year fiscal 2022, operating netbacks were $4.1 million or $61.52/bbl compared to $2.8 million or $34.20/bbl in the prior fiscal year also due to higher realized crude oil sales prices.

Royalties

Royalties	**Three months ended**	**March 31**	**Twelve months ended**	**March 31**
	2022	**2021**	**2022**	**2021**
Royalty expense ($000s)	142	96	459	314
$/bbl	9.08	5.27	6.87	3.90
% 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 Q4 fiscal 2022 consistent with Q4 fiscal 2021 and for fiscal 2022 compared with fiscal 2021.

Operating Expenses

($000s) **Operating expenses**	**Three months ended**	**March 31**	**Twelve months ended**	**March 31**
	2022	**2021**	**2022**	**2021**
Production	303	214	940	568
Transportation	504	621	2,142	2,631
	807	835	3,082	3,199
Production - $/bbl	19.36	11.74	14.07	7.05
Transportation - $/bbl	32.22	34.08	32.07	32.67
	51.58	45.82	46.14	39.72

Operating expenses for the three months ended March 31, 2022, were 13% higher than the previous year's fiscal Q4 on a per barrel basis. For the entire fiscal year, operating expenses per barrel were 16% higher than the prior year, while total expense decreased with production. Production costs during Q4 2022 were impacted by approximately $0.1 million of one-time maintenance operations associated with water injection pilot as well as industry wide inflationary pressures. Transportation costs decreased during the current quarter because of reduced water handling associated with water recycled into the water injection pilot.

General and Administrative (G&A) Expenses

($000s) **G&A**	**Three months ended**	**March 31**	**Twelve months ended**	**March 31**
	2022	**2021**	**2022**	**2021**
Net G&A expenses	892	843	2,652	2,334
Capitalized G&A expenses	35	-	168	7
Total G&A expenses	927	843	2,820	2,341

Total G&A expenses in the fourth quarter of fiscal 2022 were 10% higher than fiscal Q4 2021. The full-year fiscal 2022 G&A expenses were 20% higher than the prior year. During the prior fiscal year, the Company benefited from the Canadian federal government's emergency wages and emergency rent subsidy programs associated with the COVID-19 Pandemic. Effective September 2021, Bengal was no longer eligible for these subsidies resulting in approximately $0.1 million and $0.5 million of incremental G&A for the fiscal quarter and year ended March 31, 2022 respectively.

Share-based Compensation ("SBC")

($000s) **SBC**	**Three months ended March 31**		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
Expensed share-based compensation	37	3	135	9
Capitalized share-based compensation	5	-	10	-
	42	3	145	9

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. Share-based compensation expense is higher in fiscal 2022 due to the value of options granted in March of 2021 that were recognized during this financial year. At March 31, 2022, there were 12,445,000 outstanding options.

Depletion, Depreciation and Amortization (DD&A)

($000s) **DD&A**	**Three months ended March 31**		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
Petroleum and natural gas properties	242	293	1,033	1,285
Other assets	1	1	4	6
Right-of-use assets	8	7	30	42
	251	301	1,067	1,333
DD&A - $/bbl	15.47	16.08	15.46	15.96

The Company's proved plus probable (2P) reserve volumes at March 31, 2022, decreased by approximately 11,000 bbls compared to March 31, 2021. In addition, future capital costs to develop 2P reserves at March 31, 2022, were $61.5 million compared to $60.9 million at March 31, 2021.

Depletion expense is incurred in Australian dollars and therefore impacted by fluctuations in the foreign exchange rates between Canadian and Australian dollars. Strengthening of the Canadian dollar against the Australian dollar resulted in lower depletion per barrel for both the year and quarter ended March 31, 2022.

Production for full year fiscal 2022 was 66,797 bbls compared to 80,530 bbls for the previous year contributing to a lower total depletion for fiscal 2022.

Impairment

($000s) Impairment expense	Three months ended March 31 2022	2021	Twelve months ended March 31 2022	2021
Exploration and evaluation assets	-	-	568	-
Petroleum and natural gas properties	-	-	-	-
	-	-	568	-

As at March 31, 2022, the Company concluded that there were no triggers for impairment on its E&E assets. During Q3 Fiscal 2022, the Company recorded $0.6 million of impairment associated with uneconomic drilling results at the Chef-1 location in the ATP 752 block.

Finance Expense

($000s) Finance expense	Three months ended March 31 2022	2021	Twelve months ended March 31 2022	2021
Interest income	(7)	(1)	(7)	(1)
Accretion expense on decommissioning and restoration liability	15	5	38	19
Interest on lease liability	1	2	5	10
Interest – other	4	-	9	-
Interest on credit facility	-	136	-	881
	13	142	45	909

The Company had no outstanding credit facilities during fiscal 2022, therefore there was no corresponding interest expense.

CAPITAL EXPENDITURES

($000s) **Capital expenditures**	**Three months ended March 31**		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
Geological and geophysical and workover	2,130	63	3,489	196
Drilling	16	1	591	13
Completions	(4)	158	240	1,014
Acquisition	-	311	-	31
Office	2	-	2	-
	2,144	533	4,322	1,254

Exploration and evaluation expenditures	588	61	1,231	61
Development and production expenditures	1,554	472	3,089	1,193
Office	2	-	2	-
	2,144	533	4,322	1,254

During the quarter ended March 31, 2022, the Company incurred $0.6 million of exploration and evaluation expenditures associated with ongoing operations on the Caracal-1 well at ATP 732 to stimulate with the objective of delivering oil to surface and allowing for a Petroleum Lease application. The minimal exploration expenditures incurred during Q4 fiscal 2021 related to prospect interpretation. The $1.6 million of development expenditures incurred in the current fiscal quarter and the $3.1 million incurred during the fiscal year relate primarily to the workover operations around the Wareena-1 and Wareena-5 wells and the associated Wareena pipeline, which is currently ongoing. The objective of these workovers is to restore production to these previously producing wells. During Q4 fiscal 2021 and for the entire year of fiscal 2021, the $0.5 million and $1.2 million respectively of development expenditures related primarily to the Cuisinier water injection pilot. For the fiscal year ended March 31, 2022 $1.2 million of exploration and evaluation expenditures relate to operations at Caracal-1 and exploration wells drilled in ATP 752 (Chef-1) and ATP 934 (Legbar-1), compared to $0.1 million of expenditures in the previous year relating to processing and interpretation of geological prospects.

SHARE CAPITAL

Trading history	**Three months ended March 31**		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
High ($)	0.12	0.10	0.14	0.14
Low ($)	0.06	0.03	0.06	0.02
Close ($)	0.12	0.08	0.12	0.08
Volume (000s)	2,962	8,472	11,255	17,864
Shares outstanding (000s)	485,305	432,987	485,305	432,987
Weighted average shares outstanding (000s) - basic and diluted	446,938	227,205	436,427	133,073

At June 15, 2022, there were 485,304,515 common shares issued and outstanding, together with 12,445,000 outstanding options. On March 7, 2022 the Company closed a private placement to issue 52.3 million shares for $4.2 million of proceeds.

On February 26, 2021, Bengal issued 330,720,000 common shares as part of a private placement transaction with Texada Capital Management Ltd. (“Texada”), which is controlled by Bill Wheeler, who is a director of the Company. As part of another private placement transaction, on March 7, 2022, the Company issued 52,317,521 common shares, of which 41,067,871 were acquired by Texada. Following these transactions, Texada controls approximately 82% of the Company’s outstanding shares.

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 $3.2 million at March 31, 2022 (March 31, 2021 - $2.0 million).

At March 31, 2022, the Company had working capital[2] of $5.5 million, including cash and short-term deposits of $5.4 million, compared to working capital[2] of $4.3 million at March 31, 2021. Working capital[2] is calculated as current assets less current liabilities but excludes other obligations and current portion of decommissioning obligations.

On March 7, 2022 the Company closed a private placement to issue 52.3 million shares for $4.2 million of proceeds.

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 oil 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.

COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 2015. The Company acquired an additional 21.43% working interest and received ministerial approval for the acquisition on August 11, 2015. In Q4 fiscal 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% and 40% operating interest in the northern and southern block of this this permit. The purchase consideration was AUS$0.3 million cash and potential future cash payments of up to AUS$1.0 million, which is made up of a AUS$0.2 million on certification by an independent competent person appointed by Bengal Energy (Australia) Pty Ltd. of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of the first shipments of gas to market. The work program consists of 260 km^2 of 3D seismic and up to three wells.

[2] See "Non-IFRS and Other Financial Measures " on page 15 of this MD&A.

At March 31, 2022, the Company had the following capital work commitments:

Country and permit (1)	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2027	8.3[(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 March 31, 2022 at an exchange rate of AUS$1.00 = CAD$0.9366.

(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.

At March 31, 2022, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2022 to March 2059	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	182	103	79	-	-
Decommissioning and restoration	3,379	-	798	-	2,581
	3,561	103	877	-	2,581

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off-balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Mar 31 2022 Q4 2022	Dec 31 2021 Q3 2022	Sep 30 2021 Q2 2022	Jun 30 2021 Q1 2022	Mar 31 2021 Q4 2021	Dec 31 2020 Q3 2021	Sep 30 2020 Q2 2021	June 30 2020 Q1 2021
Oil sales	2,374	1,845	1,884	1,547	1,601	1,274	1,260	1,099
Cash flows from (used in) operations	437	607	565	(774)	70	62	(166)	335
Funds from (used in) operations(1)	515	381	417	119	(158)	130	(67)	(210)
Per share – basic and diluted ($)	0.00	0.00	0.00	0.00	(0.00)	0.00	(0.00)	(0.00)
Net income (loss)	217	(494)	85	(182)	3,040	670	(182)	400
Per share – basic and diluted ($)	0.00	(0.00)	0.00	(0.00)	0.01	0.01	(0.00)	0.00
Capital expenditures	2,074	1,392	649	137	533	498	124	99
Working capital (deficiency)(1)	5,548	2,943	3,961	4,218	4,270	(15,068)	(15,129)	(14,908)
Total assets	48,500	42,835	42,321	42,429	44,246	41,914	41,138	41,097
Shares outstanding (000s)	485,305	432,987	432,987	432,987	432,987	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	174	183	199	176	202	211	231	238
Operating netback(1) ($/bbl)	91.06	64.58	51.08	41.30	36.67	42.37	27.15	31.60

(1) See "Non-IFRS and Other Financial Measures " on page 15 of this MD&A.

Production has been declining over the past eight quarters due to natural reservoir declines in the Cuisinier oil field, with the exception of Q2 fiscal 2022, which benefited from incremental production from two wells offline for work-over activity in Q1 fiscal 2022. Ongoing volatility with a generally increasing trend in US Brent prices during the past eight quarters resulted in a trend towards increased oil sales and operating netbacks despite natural declines in production rates. Cash flow from operations in Q1 fiscal 2021 benefited from recovery of joint venture audit findings (note that subsequent audits have been delayed due to COVID 19 restrictions), followed by a use of cash in Q2 fiscal 2021 due to low commodity prices. Rising commodity pricing increased cash flow from operations with the exception of Q1 fiscal 2022 when revenue and cash flow were significantly impacted by low commodity prices. Over the years, net (losses)/income have been affected by fluctuations in foreign exchange, hedging gains and losses and capital development. Net income from Q4 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[3] deficiency occurred during the periods from Q1 fiscal 2021 to Q3 fiscal 2021 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.

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

[3] See "Non-IFRS and Other Financial Measures " on page 15 of this MD&A.

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 March 31, 2022 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 has limited 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. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

(a) Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of Cash-generating units

Petroleum and natural gas properties are aggregated into cash-generating units, for the purpose of assessing recoverability, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Impairment indicators

At the end of each reporting period, the Company reviews the petroleum and natural gas properties for external or internal circumstances that indicate that the petroleum and natural gas properties may be impaired. For the purpose of impairment testing, assets are grouped together into cash generating units ("CGU"s) for the purpose of impairment testing, which is the lowest level at which there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell ("FVLCS") and its value in use ("VIU").

The application of the Company's accounting policy for exploration and evaluation, petroleum and natural gas properties required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

(b) Key sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Impairment of petroleum and natural gas assets

Petroleum and natural gas properties are assessed for recoverability at a cash generating unit ("CGU") level. The determination of CGUs is subject to management judgements. Recoverability is assessed by comparing the carrying value of the asset to its recoverable amount, which is based on the higher of fair value of the assets less the cost to sell ("FVLCS") or value in use ("VIU").

The significant estimates used in the determination of the recoverable amount include the following:

- proved and probable oil and gas reserves and the related cash flows
- discount rates – the discount rates used to calculate the net present value of proved and probable oil and gas reserves may be influenced by changes in the general economic environment which could result in significant changes to the estimate

The estimate of proved plus probable oil and gas reserves and the related cash flows requires the expertise of independent third party reserve engineers and includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs

- Forecasted royalty costs
- Forecasted future development costs

Reserves

The estimate of proved and probable oil and gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's petroleum and natural gas properties has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101– *Standards of Disclosure For Oil and Gas Activities ("NI-51-101")*. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, forecasted oil and gas commodity prices, all of which are subject to significant judgment and interpretation. Additional the Reserve estimation includes future development costs, which represent the Company's best estimate of the nature cost and timing development activities expected in the future and required to access identified reserves. These future capital estimates include significant judgements and uncertainty.

Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: share price, expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

Liquidity

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. The current challenging economic climate may lead to adverse changes in cash flow or working capital[4] levels, which may also have a direct impact on the Company's results and financial positions. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

NON-IFRS AND OTHER FINANCIAL MEASURES

Non-IFRS Financial Measures

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. 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.

Operating Netback

Bengal utilizes operating netback as key performance indicator and is utilized by Bengal to better analyze the operating performance of its petroleum and natural gas assets against prior periods. Operating netback is calculated oil sales deducting royalties and operating expenses. The following table reconciles petroleum and natural gas revenue to netback:

[4] See "Non-IFRS and Other Financial Measures " on page 15 of this MD&A.

($000s)				
Operating netbacks				
	Three months ended March 31		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
Oil sales	2,374	1,601	7,650	5,234
Realized gain on financial instruments	-	-	-	1,033
Royalties	(142)	(96)	(459)	(314)
Operating expenses	(807)	(835)	(3,082)	(3,199)
Operating netback	1,425	670	4,109	2,754

Funds from operations

Management utilized funds from operations a measure to assess the Company's ability to generate cash not subject to short-term movements in non-cash operating working capital. Funds from operations is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. The following table reconciles cash from operations to funds from (used in) operations, which is used in this MD&A:

($000s)	**Three months ended March 31**		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
Cash from operating activities	437	70	835	301
Changes in non-cash working capital	78	(228)	597	(606)
Funds from (used in) operations	515	(158)	1,432	(305)

Capital Management measures

Working capital

Bengal uses working capital to monitor its capital structure, liquidity, and its ability to fund current operations. Working capital is calculated as current assets less current liabilities but excludes other obligations and current portion of decommissioning obligations.

Non-IFRS Financial Ratios

Bengal uses operating netback per boe to assess the Company's operating performance on a per unit of production basis. Operating netback per barrel equals operating netback divided by the applicable number of barrels.

Operating netbacks per barrel	**Three months ended March 31**		**Twelve months ended March 31**	
	2022	**2021**	**2022**	**2021**
($/bbl)				
Oil sales	151.72	87.86	114.53	64.99
Realized gain on financial instruments	-	-	-	12.83
Royalties	(9.08)	(5.27)	(6.87)	(3.90)
Operating expenses	(51.58)	(45.92)	(46.14)	(39.72)
Operating netback	91.06	36.67	61.52	34.20

Bengal uses funds from operations per share to assess the ability of the Company to generate the funds necessary for financing, operating, and capital activities on a per-share basis. This is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed.

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

Companies engaged in the oil and gas industry are exposed to a number of business risks, which can be described as operational, financial and political risks, many of which are outside of the Company's control. More specifically, these include risks of economically finding reserves and producing oil and gas in commercial quantities, marketing the production, commodity prices, environmental and safety risks, and risks associated with the foreign jurisdiction in which the Company operates. In order to mitigate these risks, the Company has an experienced base of qualified technical and financial personnel in both Canada and Australia. Further, the Company has focused its foreign operations and plans to target future foreign operations in known and prospective hydrocarbon basins in jurisdictions that have previously established long-term oil and gas ventures with foreign oil and gas companies.

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 below 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 below does not purport to be an exhaustive summary of the risks affecting Bengal.

Risks Relating to the COVID-19 Pandemic

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, 2022 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.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, for which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by Bengal will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of Bengal will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that Bengal will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Bengal may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Bengal attempts to minimize exploration, development and production risks by utilizing a high-end technical team with extensive experience and multidisciplinary skill sets to assure the highest probability of success in its drilling efforts. Bengal's collaboration of a team of seasoned veterans in the oil and gas business, each with a unique expertise in the various upstream to downstream technical disciplines of prospect generation to operations, provides the best assurance of competency, risk management and drilling success. A full cycle economic model is utilized to evaluate all hydrocarbon prospects. Detailed geological and geophysical techniques are regularly employed including 3D seismic, petrography, sedimentology, petrophysical log analysis and regional geological evaluation.

Risks Associated with Foreign Operations

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, border disputes, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labor disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Company's international operations. With respect to taxation matters, the governments and other regulatory agencies in the foreign jurisdictions in which Bengal operates and intends to operate in the future may make sudden changes in laws relating to taxation or impose higher tax rates, which may affect Bengal's operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Bengal. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Bengal, which can result in the Company having to pay significant penalties and fines. Furthermore, in the event of a dispute arising from international operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities that have prices determined based on world demand, supply and other factors, all of which are beyond the control of Bengal. World prices for oil and natural gas have fluctuated in recent years due to the impact of the COVID-19 global pandemic and recent geo-political matters. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of Bengal's oil and gas reserves. Bengal might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Bengal's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition to establishing markets for its oil and natural gas, Bengal must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas, which may be acquired or discovered by Bengal, may be affected by numerous factors beyond its control. The ability of Bengal to market its natural gas may depend upon its ability to acquire space on pipelines, which deliver natural gas to commercial markets. Bengal may also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Substantial Capital Requirements and Liquidity

Bengal's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Bengal may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Bengal to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Bengal's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it may affect Bengal's ability to expend the necessary capital to replace its reserves or to maintain its production. If Bengal's funds from (used in) operations are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Bengal.

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.

Health, Safety and Environment

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge.

Changing Regulation

Emission, carbon and other regulations impacting climate and climate related matter are dynamic and constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified by the Corporation.

Insurance

Bengal's involvement in the exploration for and development of oil and gas properties may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Bengal has insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Bengal may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Bengal. The occurrence of a significant event that Bengal is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bengal's financial position, results of operations or prospects.

Competition

Bengal actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and personnel resources than Bengal. Bengal's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Bengal's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

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 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 2022 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, 2022 (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.

Bengal
ENERGY LTD.

Consolidated Financial Statements

Years Ended
March 31, 2022 and 2021

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board outlined in the notes to the consolidated financial statements. The consolidated financial statements include certain estimates that reflect management's best judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. In the opinion of management, the consolidated financial statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards. The financial information contained in the annual report is consistent with that in the consolidated financial statements.

Management is also responsible for establishing and maintaining appropriate systems of internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to management regarding the preparation and presentation of the consolidated financial statements. Management tested and evaluated the effectiveness of its disclosure controls and procedures and internal controls over financial reporting as at March 31, 2022. During this evaluation, management identified material weaknesses due to the limited number of finance and accounting personnel at the Company dealing with complex and non-routine accounting transactions that may arise and due to a lack of segregation of duties and as a result the controls are not considered effective. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable but not absolute assurance that financial information is accurate and complete.

KPMG LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent annual general meeting, to examine the consolidated financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The Audit Committee of the Board of Directors with all of its members being independent directors, have reviewed the consolidated financial statements including notes thereto with management and KPMG LLP. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

(signed) "Chayan Chakrabarty"
Chayan Chakrabarty
President & Chief Executive Officer

(signed) "Jerrad Blanchard"
Jerrad Blanchard
Chief Financial Officer

KPMG LLP
205 5th Avenue SW
Suite 3100
Calgary AB T2P 4B9
Tel (403) 691-8000
Fax (403) 691-8008
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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bengal Energy Ltd.

Opinion

We have audited the consolidated financial statements of Bengal Energy Ltd. (the "Company"), which comprise:

- the consolidated statements of financial position as at March 31, 2022 and March 31, 2021
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at March 31, 2022 and March 31, 2021, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended March 31, 2022. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of indicators of impairment for the Cuisinier cash-generating unit, which includes the petroleum and natural gas properties therein

Description of the matter

We draw attention to notes 3 (f), 4 (a), 4 (b) and 8 to the financial statements. The Company assesses at each reporting date whether there is an indication that petroleum and natural gas properties within the Cuisinier cash generating unit (the "Cuisinier CGU") may be impaired. The Company determined that there were no external or internal indicators of impairment at March 31, 2022 for the Cuisinier CGU and no impairment tests were required. Significant management judgment is required to analyze the relevant external and internal indicators of impairment with the estimate of proved and probable oil and gas reserves and the related cash flows being significant to the assessment.

The estimate of proved and probable oil and gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs

The Company engages an independent third-party reserve engineer to estimate the proved and probable oil and gas reserves and the related cash flows as at March 31, 2022.

Why the matter is a key audit matter

We identified the assessment of indicators of impairment for the Cuisinier CGU, which includes the petroleum and natural gas properties therein, as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures with respect to the internal and external indicators of impairment, including the estimate of proved and probable oil and gas reserves and the related cash flows.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

We evaluated the Company's assessment of external and internal indicators of impairment by considering whether quantitative and qualitative information in the analysis was consistent with external market and industry data, the Company's press releases and certain minutes of the meetings of the Board of Directors and the estimate of proved and probable oil and gas reserves and the related cash flows.

With respect to the estimate of proved and probable oil and gas reserves and the related cash flows as at March 31, 2022:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve engineer engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third party reserve engineers
- We compared the fiscal 2022 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves and the related cash flows to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to fiscal 2022 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

Other Information

Management is responsible for the other information. Other information comprises:

– the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

– Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

– Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

– Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
– Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
– Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
– Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
– Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
– Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the group Company to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.
– Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditors' report is David Yung.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
June 15, 2022

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2022	2021
Assets			
Current assets:			
Cash and cash equivalents	5,11	$ 5,413	$ 4,531
Restricted cash		-	40
Trade and other receivables	6	2,646	1,224
Prepaid expenses and deposits		658	445
		8,717	6,240
Exploration and evaluation assets	7	10,352	9,890
Property, plant and equipment	8	29,508	28,116
Total assets		$ 48,577	$ 44,246
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	9	$ 3,211	$ 1,939
Current portion of lease liability	12	37	31
		3,248	1,970
Decommissioning and restoration liability	13	3,379	3,478
Lease liability	12	31	68
		6,658	5,516
Shareholders' equity:			
Share capital	14	118,796	114,636
Contributed surplus		8,015	7,870
Accumulated and other comprehensive loss		(1,078)	(336)
Deficit		(83,814)	(83,440)
		41,919	38,730
Total liabilities and shareholder's equity		$ 48,577	$ 44,246

Commitments (Note 22)
See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

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

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes	2022	2021
Revenue			
Oil sales	16	$ 7,650	$ 5,234
Royalties		(459)	(314)
		7,191	4,920
Realized gain on financial instruments	20	-	1,033
Unrealized loss on financial instruments	20	-	(1,539)
		7,191	4,414
Expenses			
General and administrative		2,652	2,334
Operating		3,082	3,199
Depletion and depreciation	8	1,067	1,333
Impairment	7	568	-
Share-based compensation		135	9
Loss (gain) on foreign exchange		16	(3,694)
		7,520	3,181
Other (income) expense			
Gain on settlement of long-term debt	11	-	(3,490)
Other		-	(114)
Finance expense	19	45	909
Net (loss) income		(374)	3,928
Exchange differences on translation of foreign operations		(742)	1,315
Comprehensive (loss) income		$ (1,116)	$ 5,243
Income (loss) per share – basic & diluted	17	$ (0.00)	$ 0.03
Weighted average shares outstanding (000s) – basic & diluted	17	436,427	133,073

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)

For the years ended March 31,	2022	2021
Share capital		
Balance beginning of the year	$ 114,636	$ 98,100
Issuance of common shares for cash	4,185	16,536
Share issue costs	(25)	-
Balance at end of year	118,796	114,636
Contributed surplus		
Balance at beginning of year	7,870	7,861
Share-based compensation - expensed	135	9
Share-based compensation – capitalized	10	-
Balance at end of year	8,015	7,870
Accumulated other comprehensive loss		
Balance at beginning of year	(336)	(1,651)
Exchange differences translation of foreign operations	(742)	1,315
Balance at end of year	(1,078)	(336)
Deficit		
Balance at beginning of year	(83,440)	(87,368)
Net (loss) income	(374)	3,928
Balance at end of year	(83,814)	(83,440)
Total shareholders' equity	$ 41,919	$ 38,730

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the years ended March 31,	Notes	2022	2021
Operating activities:			
Net (loss) income for the year		$ (374)	$ 3,928
Add (deduct) non-cash items			
Depletion and depreciation		1,067	1,333
Accretion on decommissioning and restoration liability		38	19
Accretion on credit facility		-	215
Gain on asset sale and other		-	(15)
Gain on settlement of credit facility		-	(3,490)
Share-based compensation		135	9
Interest on lease liability		5	10
Impairment	7	568	-
Unrealized loss on financial instruments		-	1,539
Unrealized foreign exchange gain		(7)	(3,853)
Funds from (used in) operations		1,432	(305)
Change in non-cash working capital	22	(597)	606
Net cash from operating activities		835	301
Investing activities:			
Exploration and evaluation expenditures	7	(1,231)	(61)
Petroleum and natural gas property expenditures	8	(3,091)	(1,193)
Change in restricted cash		40	100
Change in non-cash working capital	22	221	474
Net cash used in investing activities		(4,061)	(680)
Financing activities:			
Issuance of common shares, net of issuance costs	14	4,160	16,536
Repayment of credit facility		-	(12,649)
Lease payments	12	(36)	(53)
Change in non-cash working capital	22	-	(6)
Net cash from financing activities		4,124	3,828
Net increase in cash and cash equivalents		898	3,449
Cash and cash equivalents, beginning of year		4,531	998
Impact of foreign exchange on cash and cash equivalents		(16)	84
Cash and cash equivalents, end of year		$5,413	$ 4,531

See accompanying notes to the 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 consolidated financial statements (the "financial statements") of the Company as at March 31, 2022 and 2021 and for the years then ended are comprised of the Company and its wholly-owned subsidiaries including Bengal Energy Australia (Pty) Ltd. ("Bengal Pty") 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 1110, 715 5th Ave SW, Calgary, Alberta, Canada, T2P 2X6.

2. BASIS OF PREPARATION

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). See Note 3 for significant accounting policies.

The financial statements were approved and authorized for issuance by the Board of Directors on June 15, 2022.

These financial statements have been prepared on a historical cost basis, except for decommissioning liabilities commodity contracts as discussed in Notes 13 and 19.

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.

Evolving Demand for Energy

Changing Regulation

Emission, carbon and other regulations impacting climate and climate related matter are dynamic and constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified by the Company.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these financial statements and have been applied consistently by the Company and its subsidiaries.

(a) Basis of consolidation

The financial statements incorporate the financial statements of the Company and its wholly-owned subsidiaries Bengal Energy Australia (Pty) Ltd. and Bengal Energy International Inc.

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the financial statements from the date that control commences until the date that control ceases.

The Company recognizes in the financial statements its proportionate share of the assets, liabilities, revenues and expenses of its joint operations.

All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

(b) Cash and cash equivalents

Cash and cash equivalents include cash and all investments with a maturity of three months or less.

(c) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax “risk-free” rate that reflects current market assessments of the time value of money and the risks specific to the liability. The unwinding of the discount is recognized as a finance expense. Provisions are not recognized for future operating losses.

Decommissioning and restoration liabilities

The Company’s activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management’s best estimate of the expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

(d) Oil and natural gas exploration and evaluation expenditures

Exploration and evaluation assets (“E&E assets”)

All costs incurred prior to obtaining the legal right to explore an area are expensed when incurred.

Generally, costs directly associated with the exploration and evaluation of crude oil and natural gas reserves are initially capitalized. Exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability have not yet been demonstrated. These costs generally include unproved property acquisition costs, geological and geophysical costs, sampling and appraisals, drilling and completion costs and capitalized decommissioning costs.

Costs are held in exploration and evaluation assets until the technical feasibility and commercial viability of the project is established. Amounts are generally reclassified to petroleum and natural gas properties once probable reserves have been assigned to the field. If probable reserves have not been established through the completion of exploration and evaluation activities and there are no future plans for activity in that field, then the exploration and evaluation expenditures are determined to be impaired and the amounts are charged to profit or loss.

(e) Petroleum and natural gas properties

Petroleum and natural gas properties are stated at cost less accumulated depreciation and depletion and accumulated impairment losses. The initial cost of a petroleum and natural gas property is comprised of its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given up to acquire the asset.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depletion and depreciation

The net book value of producing assets are depleted on a field-by-field basis using the unit of production method with reference to the ratio of production in the year to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis.

Other assets are depreciated on a declining basis at rates ranging from 20% to 30% per annum.

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized as separate line items in profit or loss.

(f) Impairment

E&E assets and petroleum and natural gas properties

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and when they are reclassified to petroleum and natural gas properties. For the purpose of impairment testing, E&E assets are grouped by concession or production field with other E&E assets belonging to the same concession or production field. The impairment loss will be calculated as the excess of the carrying value over recoverable amount of the E&E impairment grouping and any resulting impairment loss is recognized in profit or loss. Recoverable amount is determined as the higher of the value in use or fair value less costs to sell
.
At the end of each reporting period, the Company reviews the petroleum and natural gas properties for external or internal circumstances that indicate that the petroleum and natural gas properties may be impaired. For the purpose of impairment testing, assets are grouped together into cash generating units ("CGU"s) for the purpose of impairment testing, which is the lowest level at which

there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell ("FVLCS") and its value in use ("VIU"). At March 31, 2022, the Company has one producing CGU, the Cuisinier field located in Australia, in the Cooper Basin.

The FVLCS is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The VIU is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. The cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

An impairment is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses, if any, are recognized on the consolidated statement of profit or loss and comprehensive profit or loss.

At the end of each subsequent reporting period, impairment losses are assessed for indicators of impairment reversal. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined, net of depletion or amortization, had no impairment loss have been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized in the statement of profit or loss and comprehensive profit or loss.

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

(g) Financial instruments

Financial instruments comprise of cash and cash equivalents, restricted cash, trade and other receivables, derivative contracts, trade and other payables and credit facility.

i. Classification and measurement of financial assets:

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated at fair value through profit or loss ("FVTPL"):

- it is held within a business model whose objective is to hold assets to collect contractual cash flows; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

A debt investment is measured at fair value through other comprehensive income ("FVOCI") if it meets both of the following conditions and is not designated at FVTPL:

- it is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

On initial recognition of an equity investment that is not held for trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in other comprehensive income ("OCI"). This election is made on an investment-by-investment basis.

All financial assets not classified as measured at amortized cost or FVOCI as described above are measured at FVTPL. On initial recognition, the Company may irrevocably designate a financial asset that otherwise meets the requirements to be measured at amortized cost or at FVOCI as measured as FVTLP if doing so eliminates or significantly reduces an accounting mismatch that would otherwise arise.

A financial asset (unless it is a trade receivable without a significant financing component that is initially measured at the transaction price) is initially measured at fair value plus, for an item not at FVTPL, transaction costs that are directly attributable to its acquisition.

The following accounting policies apply to the subsequent measurement of financial assets:

a) Financial assets at FVTPL

   These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

b) Financial assets at amortized cost

   These assets are subsequently measured at amortized cost using the effective interest method. The amortized cost is reduced by impairment losses. Interest income, foreign exchange gains and losses and impairment are recognized in profit or loss. Any gain or loss on derecognition is recognized in profit or loss.

c) Debt investments at FVOCI

   These assets are subsequently measured at fair value. Interest income calculated using the effective interest method, foreign exchange gains and losses and impairment are recognized in profit or loss. Other net gains and losses are recognized in OCI. On derecognition, gains and losses accumulated in OCI are reclassified to profit or loss.

d) Cash and cash equivalents, restricted cash, trade and other receivables, trade and other payables, and lease liability

   The fair values of these financial instruments approximate their carrying amounts due to their short-term maturity.

ii. Classification and measurement of financial liabilities:

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified at FVTPL if it is a derivative, or it is designated as such on initial recognition. Financial liabilities at FVTPL are measured at fair value and net gains and losses, including any interest expense, are recognized in profit or loss. Other financial liabilities are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in profit or loss. Any gain or loss on derecognition is also recognized in profit or loss.

The Company has classified cash and cash equivalents, restricted cash, trade and other receivables, and trade and other payables as 'amortized cost'.

iii. **Derivative financial instruments**

The Company may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company does not designate its financial derivative contracts as effective accounting hedges and therefore will not apply hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all derivative contracts are classified as Fair Value Through Profit and Loss ("FVTPL") and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein will be recognized immediately in profit or loss.

The Company may enter into physical delivery sales contracts for the purposes of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and will not be recorded at fair value on the statement of financial position. Settlements on these physical delivery contracts will be recognized in petroleum and natural gas revenue in the period of settlement.

iv. Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and stock options are recognized as a deduction from equity, net of any tax effects.

(h) Foreign currency translation

The financial statements are presented in Canadian dollars, which is the Canadian parent entity's functional and presentation currency, and the functional currency of the Australian subsidiary is Australian dollars. For the accounts of foreign operations, assets and liabilities are translated at period end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the foreign operations are included in accumulated other comprehensive income, a component of equity. Foreign currency transactions are translated into the legal entity's functional currency at the exchange rate in effect at the transaction; and any gains or losses are recorded in profit or loss.

(i) Share-based compensation

The Company accounts for share-based compensation granted to directors, officers, employees, and consultants using the Black-Scholes option-pricing model to determine the fair value of the options at grant date. An estimated forfeiture rate is incorporated into the fair value calculated and adjusted to reflect the actual number of options that vest. Share-based compensation expense is recorded and reflected as share-based compensation expense over the vesting period with a corresponding amount reflected in contributed surplus. At exercise, the associated amounts previously recorded as contributed surplus are reclassified to share capital.

(j) Revenue recognition

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

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.

(k) Per share amounts

Basic per share amounts are computed by dividing net income (loss) by the weighted average number of common shares outstanding for the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options or other dilutive instruments were exercised into common shares. The treasury stock method assumes that any proceeds upon the exercise of dilutive instruments, including remaining unamortized compensation costs, would be used to purchase common shares at the average market price of the common shares during the period.

(l) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustments to tax payable in respect of previous years.

Deferred tax is recognized providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(m) Finance income and expenses

Finance income consists of interest earned on term deposits. Finance expenses include letter of credit charges, interest on the Credit Facility, and accretion of the discount on decommissioning obligations.

(n) Determination of fair value

A number of the Company's accounting policies and disclosures required the determination of fair value, both for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Fair Value Hierarchy

Financial instruments that are measured subsequent to initial recognition at fair value are grouped into three categories based on the degree to which fair value is observable:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis;

Level 2 - Valuations are based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; including forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace;

Level 3 - Inputs that are not based on observable data for the asset or liability.

The Company's financial instruments comprise cash and cash equivalents, restricted cash, trade and other receivables, trade and other payables, credit facility and derivatives.

The Company's policy is to recognize transfers in and out of the fair value hierarchy as of the date of the event or change in circumstances that caused the transfer. There were no such transfers during the period.

Fair values have been determined for measurement and disclosure purposes as follows:

i. Derivatives

The Company's commodity contracts (swaps and put options) are measured at level 2 of the fair value hierarchy. The fair value of the swap component is determined by discounting the difference between the contracted prices and published forward price curves as at the period end date, using the remaining contracted oil volumes and a risk-free interest rate. The fair value of puts are based on option models that use publish information with respect to volatility, prices, and interest rates.

(o) Leases

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

(p) **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. During year ended March 31, 2022, the Company recognized $97,776 (2021 - $249,675) as a reduction to operating/administrative expenses related to the Canadian government wage and rental subsidy.

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 outlined below.

During the past 24 months commodity prices have been materially impacted by COVID-19 pandemic, significant geopolitical conflicts and other factors outside of the Company’s control.

The current volatile 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. 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.

(a) Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company’s accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of cash-generating units

Petroleum and natural gas properties are aggregated into cash-generating units, for the purpose of assessing recoverability, based on their ability to generate largely independent cash inflows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Impairment indicators

The Company assesses at each reporting date whether there is an indication that petroleum and natural gas properties within the Cuisinier cash generating unit (the “Cuisinier CGU”) may be impaired. Significant judgment is required to analyze the relevant external and internal indicators of impairment with the estimate of proved and probable and oil and gas reserves and the related cash flows being significant to the assessment. If any such indication exists, the asset or the CGU’s recoverable amount is estimated.

The application of the Company's accounting policy for exploration and evaluation, petroleum and natural gas properties required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

(b) Key sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Impairment of petroleum and natural gas assets

Petroleum and natural gas properties are assessed for recoverability at a CGU level. The determination of CGUs is subject to management judgements. Recoverability is assessed by comparing the carrying value of the asset to its recoverable amount, which is based on the higher of FVLCS or VIU.

The significant estimates used in the determination of the recoverable amount include the following:

- proved and probable oil and gas reserves and the related cash flows
- discount rates – the discount rates used to calculate the net present value of proved and probable oil and gas reserves may be influenced by changes in the economic environment which could result in significant changes to the estimate

The estimate of proved plus probable oil and gas reserves and the related cash flows requires the expertise of independent third-party reserve engineers and includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

Reserves

The estimate of proved and probable oil and gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's petroleum and natural gas properties has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent third-party reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, forecasted oil and gas commodity prices, and timing of future expenditures, all of which are subject to significant judgment and interpretation.

Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees, and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: share price, expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

Liquidity

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. The current challenging economic climate may lead to adverse changes in cash flow or working capital levels, which may also have a direct impact on the Company's results and financial positions. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

5. CASH AND CASH EQUIVALENTS

Cash and cash equivalents at the end of the reporting period as shown in the statement of financial position are comprised of:

($000s)	March 31, 2022	March 31, 2021
Cash and bank balances	1,412	4,531
Short-term deposits	4,000	-
	5,412	4,531

6. 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)	March 31, 2022	March 31, 2021
Due from joint venture partners	2,635	1,206
Other receivables	11	18
	2,646	1,224

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

($000s)	
Balance, April 1, 2020	8,930
Additions	61
Exchange adjustments	899
Balance, March 31, 2021	9,890
Additions	1,231
Impairment	(568)
Capitalized share-based compensation	4
Exchange adjustments	(205)
Balance, March 31, 2022	10,352

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

($000s)	
ATP 732P – Tookoonooka	5,224
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,683
ATP 934 – Barrolka	1,983
Other	-
Balance, March 31, 2021	9,890

($000s)	
ATP 732P – Tookoonooka	5,730
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,623
ATP 934 – Barrolka	1,972
Other	27
Balance, March 31, 2022	10,352

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.

In December of 2021 the Company recorded $0.6 million of impairment associated with uneconomic drilling results in the ATP 752 Barta Block.

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

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, April 1, 2020	43,822	344	219	44,385
Additions	1,193	-	-	1,193
Disposals	-	-	(76)	(76)
Change in decommissioning and restoration liability	(623)	-	-	(623)
Exchange adjustments	6,388	-	-	6,388
Balance, March 31, 2021	50,780	344	143	51,267
Additions	3,089	2	-	3,091
Capitalized share-based compensation	6	-	-	6
Change in decommissioning and restoration liability	(59)	-	-	(59)
Exchange adjustments	(1,499)	-	-	(1,499)
Balance, March 31, 2022	52,317	346	143	52,806

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment losses:				
Balance, April 1, 2020	17,727	319	47	18,093
Depletion and depreciation	1,285	6	42	1,333
Disposals	-	-	(28)	(28)
Exchange adjustments	3,753	-	-	3,753
Balance, March 31, 2021	22,765	325	61	23,151
Depletion and depreciation	1,033	4	30	1,067
Exchange adjustments	(920)	-	-	(920)
Balance, March 31, 2022	22,878	329	91	23,298

($000s)				
Net carrying amount:				
At March 31, 2021	28,015	19	82	28,116
At March 31, 2022	29,439	17	52	29,508

At March 31, 2021 and 2022, the Company determined that there were no external or internal indicators of impairment. As a result, a quantitative impairment test was not performed. During fiscal 2022, the Company capitalized $0.1 million general and administrative expense (2021 - $nil). The calculation of depletion for the year ended March 31, 2022 included $61.5 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2021 - $60.9 million).

9. TRADE AND OTHER PAYABLES

($000s)	March 31, 2022	March 31, 2021
Trade payables	2,370	1,434
Accrued liabilities and other payables	841	505
	3,211	1,939

10. INCOME TAXES

The provision for income taxes differs from the amount obtained in applying the combined federal and provincial income tax rates to the loss for the year. The difference relates to the following items:

($000s) Year ended March 31	2022	2021
(Loss) Income before taxes	(374)	3,928
Statutory tax rate	23.5%	23.5%
Expected income tax recovery	(88)	923
Change in enacted tax rates	-	-
Share-based compensation	41	3
Foreign exchange	6	1,423
Effect of tax rate in foreign jurisdiction	49	325
Other	780	140
Changes in unrecognized tax asset	(788)	(2,814)
Income tax recovery	**-**	-

The deductible temporary differences included in the Company's unrecognized deferred income tax assets are as follows:

($000s) Year ended March 31	2022	2021
Non-capital losses	45,618	44,789
Net capital losses	-	5,983
P&NG properties	8,669	8,728
	54,287	**59,500**

The components of the Company's and its subsidiaries deferred income tax assets are as follows:

($000s)		
Year ended March 31	**2022**	**2021**
Property, plant and equipment	6,206	5,763
Fair value of financial instruments	-	(5)
Foreign exchange	1,331	1,353
Decommissioning obligations	(1,014)	(1,043)
Non-capital losses	(6,523)	(6,068)
	-	-

At March 31, 2022, the Company had approximately $38.9 million and $28.5 million of non-capital losses in Canada and Australia respectively (2021 - $29.3 million and $29.0 million, respectively), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2026 to 2042. The Australian non-capital losses have no term to expiry. The Company's ongoing drilling activities continue to generate deferred tax assets related to Petroleum Resource Rent Tax in its Australian subsidiary, which has not been recognized.

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At March 31, 2022, the Company has no deferred tax liabilities in respect of these temporary differences.

11. CREDIT FACILITY

On February 26, 2021, the Company completed its debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac Banking Corporation ("Westpac") under its secured credit facility (the "Credit Facility") whereby the total balance outstanding of US$ 12.5 million was settled in exchange for a payment of US $10.0 million resulting in a gain on settlement of $3,490. In conjunction with this, the Company entered into a recapitalization transaction with Texada Capital Management Ltd. ("Texada") (Note 14). The transaction included the issuance of 330,720,000 shares at a price of $0.05 per share for proceeds of $16.5 million, of which $12.6 million (corresponding to US $10.0 million at the transaction date) were used as settlement payment to Westpac.

12. LEASE LIABILITY

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

($000s)	
Balance, March 31, 2021	99
Interest	5
Payments	(36)
Balance, March 31, 2022	68
Current portion of lease liability	(37)
Non-current portion of lease liability	31

13. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2020	3,690
Change in estimate	(623)
Accretion	19
Exchange adjustments	392
Balance, March 31, 2021	3,478
Change in estimate	(59)
Accretion	38
Exchange adjustments	(78)
Balance, March 31, 2022	3,379

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total unadjusted and uninflated cash flows required to settle its decommissioning and restoration costs at March 31, 2022 is approximately $3.4 million (March 31, 2021 – $3.5 million) which will be incurred between 2025 and 2059. An inflation factor of 3.05% (March 31, 2021 – 1.1%) and a risk-free discount rate of 3.50% (March 31, 2021 – 1.74%) have been applied to the decommissioning liability at March 31, 2022.

14. 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	102,266,694	98,100
Issuance of common shares for cash	330,720,000	16,536
Balance at March 31, 2021	432,986,694	114,636
Share cancellation	(300)	-
Issuance of common shares for cash, net of issuance costs	52,317,821	4,160
Balance at March 31, 2022	485,304,215	118,796

On February 26, 2021, Bengal issued 330,720,000 common shares at $0.05 per share as part of a private placement transaction with Texada Capital Management Ltd. ("Texada"), which is controlled by Bill Wheeler, who acts as a director of the Company. As part of another private placement transaction, on March 7, 2022, the Company issued 52,317,521 common shares at $0.08 per share, of which 41,067,871 were acquired by

Texada. Following these transactions, Texada controls approximately 82% of the Company's outstanding shares. Issuance costs related to the private placement totaled $25,000.

15. 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 market price of the Company's common shares on the date of the grant.

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
Granted	11,340,000	0.08
Expired	(1,012,500)	0.16
Forfeited	(83,333)	0.11
Balance, March 31, 2021	13,716,667	0.08
Granted	1,050,000	0.09
Expired	(641,667)	0.10
Forfeited	(1,680,000)	0.08
Balance, March 31, 2022	12,445,000	0.08
Exercisable, March 31, 2022	5,015,000	0.09

		Options Outstanding	Options Exercisable
Exercise Price	**Number Outstanding**	**Remaining Life (years)**	**Number Exercisable**
$0.10	1,735,000	0.25	1,735,000
$0.09	1,050,000	4.58	-
$0.08	9,660,000	4.00	3,280,000
	12,445,000	3.53	5,015,000

The fair value of the options granted during fiscal 2022 and 2021 were estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

Assumptions:	**Fiscal 2022**	**Fiscal 2021**
Risk-free interest rate (%)	1.50	1.00
Expected life (years)	5	5
Expected volatility (%)(1)	119	29
Estimated forfeiture rate (%)	20	20
Weighted average fair value of options granted	$0.07	$0.02
Weighted average share price on date of grant	$0.09	$0.08

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

The fair value of the 1,050,000 stock options granted during fiscal 2022 was approximately $78,000. The fair value of the 11,340,000 stock options granted during fiscal 2021 was approximately $200,000.

16. 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 June 30, 2022, whereby delivery takes place through the contract period. Revenues are typically collected 60 days following delivery to Port Bonython. The Cuisinier Joint Venture is currently negotiating a revised COSP Agreement to become effective July 1, 2022 through to December 31, 2023 with terms anticipated to be similar to the current agreement.

17. PER SHARE AMOUNTS

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

($000s except per share amounts) Year ended March 31	2022	2021
Net (loss) income for the year	(374)	3,928
Weighted average number of common shares – basic and diluted (000s)	436,427	133,073
Basic and diluted (loss) income per share	$ (0.00)	$ 0.03

For the year ended March 31, 2022, there were 12,445,000 (March 31, 2021 - 13,716,667) options considered anti-dilutive.

18. COMPENSATION OF KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

($000s) Year ended March 31	2022	2021
Salaries and employee benefits	666	706
Share-based compensation(1)	8	8
	674	714

(1) Represents the amortization of share-based compensation expense associated with the Company's share-based compensation plans granted to key management personnel.

19. FINANCE EXPENSE

($000s) Year ended March 31	2022	2021
Interest income	(7)	(1)
Accretion on decommissioning and restoration liability	38	19
Interest on lease liability	5	10
Interest on credit facility	-	881
Interest – other	9	-
	45	909

20. FINANCIAL RISK MANAGEMENT

The Company has exposure to credit, liquidity and market risk from its use of financial instruments. This note presents information about the Company's exposure to these risks, the Company's objectives and policies and processes for measuring and managing risk.

The Board of Directors has overall responsibility for identifying the principal risks of the Company and ensuring the policies and procedures are in place to appropriately manage these risks. Bengal's management identifies, analyzes and monitors risks and considers the implication of the market condition in relation to the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at March 31, 2022, Bengal's receivables consisted of $2.6 million (March 31, 2021 - $1.2 million) from joint venture partners (all of which has been collected subsequent to year end) and $0.1 million (March 31, 2020 - $nil) of other receivables.

Bengal has a COSP Agreement with a purchaser and has not experienced any collection problems to date.

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

The Company had no accounts considered past due at March 31, 2022 (March 31, 2021 - $nil). Past due is considered greater than 90 days outstanding.

Bengal did not provide any amounts for doubtful accounts during 2022 nor was it required to write-off any receivables during 2022

Cash and cash equivalents, when held, consist of cash bank balances and guaranteed investment certificates redeemable at any time. Bengal manages the credit exposure related to guaranteed investments by selecting counterparties based on credit ratings and monitors all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset-backed commercial paper.

(b) 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 and lease liability and amounted to $3.2 million at March 31, 2022 (March 31, 2021 - $2.0 million).

At March 31, 2022, the Company had working capital, which the Company defines as total current assets less total current liabilities, of $5.5 million, including cash and cash equivalents of $5.4 million, compared to working capital of $4.3 million at March 31, 2021.

In February 2021, the Company raised $16.5 million on the issuance of common shares and extinguished it's previously outstanding credit facility. In March 2022, the Company raised $4.2 million on the issuance of common shares. Management anticipates that operating and capital requirements during fiscal 2023 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 towards lower risk projects with near-term cash flow upside.

(c) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: foreign currency risk, commodity price risk and interest rate risk. The Company is exposed to market risks resulting from fluctuations in foreign exchange rates, commodity prices and interest rates in the normal course of operations. A variety of derivative instruments may be used to reduce exposure to these risks.

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives US 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 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 March 31, 2022:

($000s)				
	CAD$	**AUS$**	**US$**	**Total**
Cash and cash equivalents	5,359	39	14	5,412
Trade and other receivables	11	129	2,506	2,646
Trade and other payables	(238)	(2,973)	-	(3,211)
Lease liability	(68)	-	-	(68)
	5,064	(2,805)	2,520	4,779

Exchange rates as at March 31:	**2022**	**2021**
Number of CAD$ for 1 AUS$	0.94	0.96
Number of CAD$ for 1 US$	1.25	1.26

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.

During the 2021 fiscal year, the Company recorded an unrealized loss of $1.5 million on its derivative contracts. These contracts were settled in Q3 of the fiscal year resulting in a realized gain of $1.0 million. At March 31, 2022 and 2021, the Company had no derivative contracts outstanding and all unrealized gains booked through fiscal 2021 were effectively realized during the year. During fiscal 2022 there were no realized on unrealized gains recognized.

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's exposure to interest rate risk on its cash and cash equivalents at March 31, 2022 is restricted to investments with a maturity of three months or less. The Company had no interest rate derivatives at March 31, 2022 and 2021.

21. CAPITAL MANAGEMENT

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility which will allow it to execute on its capital investment program, provide creditor and market confidence and to sustain future development of the business. Following the February 2021 recapitalization transaction, the Company has materially realigned its capital structure eliminated all outstanding debt while adding $4.0 million of working capital. The Company raised a further $4.2 million in March 2022. This provides additional financial and capital flexibility further to the Company's strategy described above.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions, including: changes in economic conditions, the risk profile of its drilling inventory, the efficiencies of past investments, the efficiencies of forecasted investments and the timing of such investments, the forecasted cash balances, the forecasted commodity prices and resulting cash flow.

In order to maintain or adjust the capital structure, the Company may from time to time issue shares (if available on reasonable terms), issue debt instruments, sell assets, farm out properties and adjust its capital spending to manage current and projected cash levels. There can be no assurance that equity financing will be available or sufficient to meet capital commitments, or for other corporate purposes, or if equity financing is available, that it will be on terms acceptable to the Company.

22. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s) **Year ended March 31**	**2022**	**2021**
Trade and other receivables	(1,422)	415
Prepaid expenses and deposits	(213)	(319)
Trade and other payables	1,272	898
Effect of change in foreign exchange rates	(13)	80
	(376)	1,074
Attributable to:		
Operating	(597)	606
Investing	221	474
Financing	-	(6)
	(376)	1,074

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

Cash interest paid and received ($000s) **Year ended March 31**	**2022**	**2021**
Cash interest paid	9	623
Cash interest received	7	1

23. 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% and 40% operating interest in the northern and southern block of this permit respectively. The purchase consideration was AUS\$0.3 million cash and potential future cash payments of up to AUS\$1.0 million, which is made up of a AUS\$0.2 million on certification by an independent competent person appointed by Bengal Energy (Australia) Pty Ltd. of not less than 25 billion cubic feet of proved reserves and AUS\$0.8 million due upon the delivery of the first shipments of gas to market. The work program consists of 260 km^2 of 3D seismic and up to three wells.
At March 31, 2022, the Company had the following capital work commitments:

Country and permit (1)	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2027	8.3[(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 March 31, 2022 at an exchange rate of AUS$1.00 = CAD$0.9366.

(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.

At March 31, 2022, the contractual obligations for which the Company is responsible are as follows:

($000s)

Contractual obligations

	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	182	103	79	-	-
Decommissioning and restoration	3,379	-	798	-	2,581
	3,561	103	877	-	2,581

24. SEGMENTED INFORMATION

As at March 31, 2022, 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 year ended March 31, 2022	**Australia**	**Corporate**	**Total**
Revenue	7,650	-	7,650
Interest revenue	-	7	7
Interest expense	9	5	14
Depletion and depreciation	1,033	34	1,067
Impairment	568	-	568
Net income (loss)	696	(1,070)	(374)
Exploration and evaluation expenditures	1,231	-	1,231
Petroleum and natural gas property expenditures	3,089	-	3,089
($000s)			
As at March 31, 2022			
Exploration and evaluation assets	10,352	-	10,352
Petroleum and natural gas properties	29,508	-	29,508
Total assets	43,104	5,472	48,576
Total liabilities	6,352	306	6,658

$000s)			
For the year ended March 31, 2021	**Australia**	**Corporate**	**Total**
Revenue	5,234	-	5,234
Interest revenue	-	1	1
Interest expense	881	10	891
Depletion and depreciation	1,285	48	1,333
Net income (loss)	4,737	(809)	3,928
Exploration and evaluation expenditures	61	-	61
Petroleum and natural gas property expenditures	1,193	-	1,193
($000s)			
As at March 31, 2021			
Exploration and evaluation assets	9,890	-	9,890
Petroleum and natural gas properties	28,116	-	28,116
Total assets	40,084	4,162	44,246
Total liabilities	5,084	432	5,516

CORPORATE INFORMATION

AUDITORS

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LEGAL COUNSEL

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Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
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

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Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE

James B. Howe (Chairman)
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Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Jerrad Blanchard, Chief Financial Officer
Bruce Allford, Secretary

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