INTERNATIONAL EXPLORATION & PRODUCTION

2023 Annual Report
Twelve Months Ended
March 31, 2023

BENGAL ENERGY LTD

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

Bengal enters fiscal 2024 with zero debt, the ability to dedicate its free cash flow from operations to our operated projects in the Cooper Basin, and we are entirely committed to generating value for shareholders. The team has continued to deliver a strong operating performance in the context of an evolving energy and economic environment and despite softening in the global crude oil markets compared with the prior year.

Global instability continues to impact the economy, driving inflation, disrupting markets, and causing volatility in commodity prices. As a result, energy security has become a key priority for Canada and Australia, alongside decarbonization.

The near-term outlook for crude oil and natural gas prices in the Australian market has stabilized post Covid and despite global conflicts. We are now encouraged by the bullish medium-term 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 priced on the spot market over US$70 per barrel and east coast Australia spot gas prices over Australian $12 per gigajoule.

Production for the fiscal year ended March 31, 2023, averaged 180 barrels of oil per day, and we generated annual operating netback of $4.45 mm. Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2023, are 5,477 thousand barrels of oil ("Mbbls"), and Proved ("1P") reserves are 2,005 Mbbls compared with 5,778 Mbbls and 2,145 Mbbls for 2P and 1P reserves respectively at March 31, 2022. The net present value (NPV10, before tax) of Bengal's 2P reserves, net of future development costs, at March 31, 2023, is $121.0 million, or $0.25 per share compared to $149 million at March 31, 2022. The 2P after-tax net asset value is $95 million for the current year compared with $115 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, 2023, 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.

During the year, the Company continued capital programs on two of its 100% owned and operated projects at Wareena (Petroleum Lease("PL") 110 and Production Pipeline ("PPL") 138 and Caracal well (Authority to Prospect ("ATP") 732 and Potential Commercial Area ("PCA" 332).

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 nearing completion, 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. 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. We are immensely proud to have commissioned and are now operating the first gas-fired Digital Mining Donga in the Cooper Basin with prototype goals allowing us to commercialise non-producing discovered natural gas resources that are not pipeline connected. The Caracal-1 well, a 53 API oil discovery on ATP 732, was re-entered and produced oil to the surface. While this well has proven to be non commercial it is currently being assessed to determine capacity for improved commercial production through further downhole stimulation and/or new well drilling in an optimum structural location. The Company has secured an offtake agreement for this oil with the nearby Inland Oil Refinery, and in parallel has been successful with a longer-term lease retention application (PCA 332) for this prospective block with multiple egress options for its crude oil resources.

The Company has made considerable progress with the deployment of both our Early Oil Production System (EOPS) and our Early Gas Production System (EGPS). Both systems have now been successfully field-tested and 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. In addition to the development and deployment of our EOPS and EGPS systems, we are targeting low carbon developments with our green hydrogen and carbon farming initiatives. Bengal aims to be at the forefront of net-zero technology as part of the decarbonization solution. We are achieving this through strong partnerships with local service providers Ago Vires, Fyfe and InGauge. In addition, we are collaborating closely with landholders across all our operated assets, and with the Traditional Owners of our tenements including leveraging our projects to create employment opportunities. As we mature these opportunities, we expect to announce updates outlining expected benefits to all shareholders from these technologies being developed by the Company.

In Bengal's non-operated Cuisinier oilfield, a pilot reservoir pressure maintenance scheme was initiated during the 2021 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 both to 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 sub-surface 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. 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, Bengal would fully support the Joint Venture ("JV") beginning a multi-phase water injection scheme, targeted fracture stimulation and more commercially efficient development drilling.

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 wells has a Jurassic oil resource which we are planning to access with a dual packer and sliding side sleeve completion. We are currently 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 are working on attracting 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. 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.

In addition, our team has continued to evaluate strategic acquisitions, farm-ins and other opportunities in the current market. Bengal has an exciting outlook for value creation across our project portfolio, supported by a healthy financial footing.

Despite enduring a prolonged period of challenging capital markets, we have remained resilient and focused on achieving the best possible results. Our unwavering commitment to delivering value has allowed us to navigate through these difficulties successfully. By optimizing operations, managing costs, and adapting to the changing landscape, we have achieved commendable outcomes. We appreciate your ongoing support and confidence as we continue to navigate these challenges and seize opportunities for growth. Together, we will persevere and create long-term value.

Our success will continue to be driven by our dedicated and talented 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 that we rely on as we drive toward 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, 2023, and 2022

International Exploration & Production

Management's Discussion & Analysis

Three and Twelve Months Ended
March 31, 2023, and 2022

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, 2023.

This MD&A dated June 14, 2023, should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2023 and 2022. 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, 2023 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended March 31, 2023, may be referred to as "fourth quarter of fiscal 2023", "Q4 fiscal 2023", "Q4 FY 2023", "current quarter", and "the quarter". The comparative three months ended March 31, 2022, may be referred to as "fourth quarter of fiscal 2022", "Q4 fiscal 2022" "Q4 FY 2022", and "prior year's quarter". The year ended March 31, 2023, may be referred to as "fiscal 2023", "current year", and "the year". The comparative year ended March 31, 2022, may be referred to as "the previous year", "prior year", and "fiscal 2022".

FOURTH QUARTER FISCAL 2023 SUMMARY

Financial Summary:

- **Reserves –** Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2023, are 5,477 thousand barrels of oil ("Mbbls") compared to 5,778 Mbbls at March 31, 2022. 2P 1P reserves are2005 Mbbls compared to 2145 Mbbls at March 31, 2022. The lower reserves result primarily from the prior year's production without replacement during fiscal 2023. The net present value (NPV[1]$_{10}$, before tax) of Bengal's 2P reserves, net of future development costs, at March 31, 2023 is $121 million, or $0.25 per share compared to $149 million at March 31, 2022. The 2P after tax net asset value is $95 million for the current year compared to $115 million in the prior year. The lower NPV is primarily the result of expected higher future development costs as a result inflationary pressure across Queensland.
- **Sales revenue** – Reflecting lower oil prices, crude oil sales revenue was $2.0 million in the fourth quarter of fiscal 2023, which is 18% lower than the $2.4 million recorded in Q4 fiscal 2022. Full year fiscal 2023 sales revenue was $8.1 million compared to $7.7 million for the full year fiscal 2022.
- **Funds (used in) from operations[2]** – Bengal used $0.4 million of funds in operations during Q4 fiscal 2023 compared to a $0.5 million funds from operations during Q4 fiscal 2022. For the full year fiscal 2022, the Company generated $2.0 million of funds from operations compared to $1.4 million funds used in operations during the prior fiscal year. During Q4 fiscal 2023, Santos, the Cuisinier joint venture operator undertook a self-review with the Queensland Revenue Office relative to its royalty payments for the calendar years of 2015 through 2020. The result was a $3.0 million additional royalty liability ($0.9 million net to Bengal) assessed to the Cuisinier Joint Venture. The net amount was recorded as an offset to other income for the quarter ended March 31, 2023. Santos is currently reviewing their royalty obligations and Bengal is disputing these additional charges under its Joint Operating Agreement; however, the Company has recorded the full net amount as an offset to other income for the quarter ended March 31, 2023. Absent this unusual royalty adjustment, the Company's funds from operations would be $0.5 million for the quarter and $2.9 million for the year.

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[1] See "Abbreviations" on page 17 of this MD&A

[2] See "Non-IFRS and Other Financial Measures" on page 15,16 of this MD&A

- **Net income** - Bengal reported a net loss of $0.8 million for the current quarter compared to net income of $0.2 million in the fourth quarter of fiscal 2022. For the full year fiscal 2023, the Company reported net income of $0.7 million compared to a net loss of $0.4 million in the prior year. Net income during the current quarter was materially impacted by the royalty adjustment described above.Net income for the year was also positively impacted by $1.1 of million other income related to the settlement of a crude oil stock discrepancy recorded in Q2 fiscal 2023 as well as a $0.9 million offset to other income related to the Cuisinier royalty adjustment described above.

Operational Summary:

- **Production volumes** – The Company's share of total production in the current quarter was 16,395 bbls of light crude oil, which is a 4.8% increase from the 15,647 bbls produced in the fourth quarter of fiscal 2022. The current quarter production averaged 182 bbls/day compared to 174 bbls/day produced in the fourth quarter of fiscal 2022. Full year fiscal 2023 saw total production of 65,680 bbls compared to 66,797 bbls for full year fiscal 2022. The full year fiscal 2023 production per day averaged 180 bbls compared to 183 bbls/day for the full year fiscal 2022.
- **Capital expenditures** – During the year, the Company continued 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 $0.4 million in capital expenditures during Q4 fiscal 2023 as compared to $2.2 million in Q4 fiscal 2022 and a total of $7.7 million during the current year compared to $4.3 million during fiscal 2022.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

Bengal's producing and non-producing assets are situated primarily 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, the recently granted Potential Commercial Area ("PCA") 332 and its four 100% operated petroleum licenses (PL 114 Wareena, PL 157 Ghina, PL 188 Ramses, PL 411 Karnak) 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. While 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, an application can be made to continue a portion of the permit in the form of a PCA. 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 including a producing pipeline license ("PPL") 138 adjacent to the 100% owned ATP 934.

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

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

A pilot water injection-driven reservoir pressure maintenance scheme was initiated and after resolving mechanical issues, water injection activities commenced during calendar Q4 2021. This project 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. On establishing success of the pilot, the Joint Venture will begin a multi-staged water injection scheme, targeted fracture stimulation and more commercially efficient development drilling. The Joint Venture has observed compelling evidence that the overall field decline has been temporarily arrested with a modest upward trend in oil production rate in affected wells during the current quarter.

Bengal's joint venture partner and operator of the Cuisinier pool has indicated its intent to drill four wells in the Cuisinier field during calendar 2023. Bengal will not participate in this program given that the operator has not prepared a suitable field development plan considering the water injection pilot and projected capital and operating costs make such investment less attractive than alternatives available in Bengal's inventory.

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

The Company has a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market. These non-productive PLs are highly compatible with the the 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 and an existing gas pipeline to produce raw gas into existing infrastructure at PL 114 Wareena. The Company completed workover activities at Wareena 1 and Wareena 5 in November 2022. Initial test results indicate Wareena 1 would require additional stimulation and dewatering to yield commercial production rates. The Company is encouraged by wellhead pressure measured at Wareena 5 and therefore additional testing is planned subject to the availability of equipment. If this testing yields commercial rates, Bengal will tie-in the producing well to pipeline PPL 138. The Company is investing in proprietary proof of concept arrangement to allow commercial gas production prior to a pipeline connection with all required equipment now on site.

The 100% ownership of these assets presents an appraisal and development opportunity that will be operated. by the Company and is seen as a key steppingstone for Bengal's natural gas platform upon which future development and appraisal work at the existing PLs and 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 surface, although at lower-than-expected rates and is currently being assessed to determine capacity for commercial production versus drilling a more optimally placed appraisal well to assess the extent of the structure.

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 732 reached the end of its term in March of 2023 and the Company lodged an application over the northern portion of the ATP for continuation in the form of PCA 332 for a further 15 years. Based on the positive results from Caracal-1, the application was approved on January 30, 2023. In addition, the Company is assessing farm-in interest on other 3D defined drilling targets on PCA 332. The PCA, granted by the Queensland Government in record time, provides much-needed certainty for Bengal to focus on its hydrocarbon projects in the Talgeberry-Tintaburra corridor. The majority of PCA 332 is covered by 3D seismic which has outlined the prospective targets as described in the Company's press release: "Bengal Energy Announces Independent Oil and Natural Gas Resource Report" dated March 30, 2022.

ATP 934 Barrolka East (100% WI)

ATP 934 is the Company's 100% owned natural gas exploration block. Bengal received approval of a special amendment for ATP 934 in March 2021 which relinquished 50% of the existing ATP area and extended the term of the ATP by entering an outcome based LWP for another 6 years to February 28, 2027. As part of the special amendment, another relinquishment of 118 sub blocks (50% of the remaining sub blocks) (88,972 acres) was required by February 28, 2023. The relinquishment was accepted by the regulator during April of 2023.The relinquished area was not considered to be prospective by the Company due to the lack of identified prospects and limited physical access. The LWP includes the drilling of up to 3 wells and 260 km^2 of 3D seismic.

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[1] amounts		**Three months ended March 31, 2023**		**2022**		**Twelve months ended March 31, 2023**		**2022**
Oil revenue	$	1,954	$	2,374	$	8,149	$	7,650
Operating netback[1]	$	1,078	$	1,425	$	4,452	$	4,109
Cashflow from (used in) operations	$	(704)	$	437	$	2,111	$	835
Funds from (used in) operations[1]	$	(431)	$	515	$	1,988	$	1,432
Per share ($) (basic and diluted)	$	(0.00)	$	0.00	$	0.00	$	0.00
Net income (loss)	$	(803)	$	217	$	703	$	(374)
Per share ($) (basic and diluted)	$	(0.00)	$	0.00	$	0.00	$	(0.00)
Capital expenditures	$	395	$	2,244	$	7,715	$	4,322
Oil volumes (bbls/d)		182		174		180		183
Operating netback[1] ($/bbl)	$	65.75	$	91.06	$	67.79	$	61.52

(1) Non-IFRS and Other Financial Measures

RESULTS OF OPERATIONS

Production

	Three months ended March 31 2023	**2022**	**Twelve months ended March 31 2023**	**2022**
Oil production (bbls/d)	182	174	180	183
Oil production (bbls)	16,395	15,647	65,680	66,797

Production during Q4 fiscal 2023 increased 5% compared the Q4 fiscal 2022 and total current fiscal year production decreased 2% compared to the fiscal 2022. Production rates appear to have been positively impacted by the Cuisinier pilot water injection program. The joint venture has observed compelling evidence that the overall field decline has been temporarily arrested with a modest upward trend in oil production rate in affected wells during the current quarter.

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		Twelve months ended March 31	
		2023	2022	2023	2022
	Oil lifting				
	Volume (000s bbls)	15.10	14.0	66.42	67.3
	Weighted average price ($US/bbl)	85.36	107.36	96.94	83.66
A.	Sales (CDN $000's)	1,508	1,864	8,372	7,131
	Pipeline oil				
	Volume (000s bbls), change	4.4	1.6	(0.8)	(0.5)
	Price ($US/bbl), change	(2.49)	30.20	15.44	(50.63)
B.	Net sales (CDN $000's)	446	510	(223)	519
A.+B.	Total oil sales (CDN $000s)	1,954	2,374	8,149	7,650

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 Port Bonython (export port) and which remains in the custody of the producer. Lifting occurs when the oil is moved from the port to the ship at which point it is priced and sold.

Realized crude oil prices during the current quarter decreased by 20% compared to the prior year's quarter based on decreased benchmark Brent pricing. The realized weighted average price of oil lifting sales was US $85.36/bbl for the current quarter compared to US $107.36/bbl during Q4 fiscal 2022.

During the current quarter the volume of unsold pipeline oil increased by approximately 4,400 bbls; however, the pricing of those barrels decreased by US$2.49/bbl. After adjusting for changes in pipeline oil, sales for the current quarter are $1.9 million, which is an 18% decrease from the $2.4 million recorded during the prior year's quarter.

The following table outlines average benchmark prices:

	Three months ended March 31		Twelve months ended March 31	
	2023	2022	2023	2022
Brent oil ($/bbl)	109.52	127.38	127.25	100.69
Brent oil (US$/bbl)	81.17	100.30	95.99	80.55
Number of CAD$ for 1 AUS$	0.92	0.92	0.91	0.93
Number of CAD$ for 1 US$	1.35	1.27	1.33	1.25

($000s)

Operating netbacks[1]

	Three months ended March 31		Twelve months ended March 31	
	2023	**2022**	**2023**	**2022**
Oil sales	1,954	2,374	8,149	7,650
Realized gain on financial instruments	-	-	-	-
Royalties	(155)	(142)	(596)	(459)
Operating expenses	(721)	(807)	(3,101)	(3,082)
Operating netback	1,078	1,425	4,452	4,109
($/bbl)				
Oil sales	119.18	151.72	124.07	114.53
Realized gain on financial instruments	-	-	-	-
Royalties	(9.45)	(9.08)	(9.07)	(6.87)
Operating expenses	(43.98)	(51.58)	(47.21)	(46.14)
Operating netback	65.75	91.06	67.79	61.52

(2) See Non-IFRS and Other Financial Measures

In Q4 fiscal 2023, operating netbacks were $1.1 million or $65.75/bbl compared to Q4 fiscal 2022 at $1.4 million or $91.06/bbl. The primary reason for the 28% decrease in operating netbacks relates to decreased commodity pricing realized during this quarter. For the full year fiscal 2022, operating netbacks were $4.5 million or $67.79/bbl compared to $4.1 million or $61.52/bbl in the prior fiscal year also due better realized commodity pricing.

Royalties

Royalties

	Three months ended March 31		Twelve months ended March 31	
	2023	**2022**	**2023**	**2022**
Royalty expense ($000s)	155	142	596	459
$/bbl	9.45	9.08	9.07	6.87
% of revenue	8	6	7	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%.

Operating Expenses

($000s) **Operating expenses**	Three months ended March 31		Twelve months ended March 31	
	2023	**2022**	**2023**	**2022**
Production	151	303	924	940
Transportation	570	504	2,177	2,142
	721	807	3,101	3,082
Production - $/bbl	9.19	19.36	14.07	14.07
Transportation - $/bbl	34.79	32.22	33.14	32.07
	43.98	51.58	47.21	46.14

Operating expenses for the three months ended March 31, 2023, were 15% lower than the prior year's fiscal Q4 on a per barrel basis. For the entire fiscal year, operating expenses per barrel were 2% higher than the prior year. Production costs during Q4 2022 were impacted by approximately $0.1 million of non-standard maintenance operations associated with water injection pilot, which was absent during the current quarter. The marginal increase in transportation costs during the year and quarter ended March 31, 2023, was driven primarily by inflationary escalation in the underlying transportation agreements. Current quarter operating costs are consistent with the Operator's budgeted costs absent of unexpected future activities.

General and Administrative (G&A) Expenses

($000s) **G&A**	Three months ended March 31		Twelve months ended March 31	
	2023	**2022**	**2023**	**2022**
Net G&A expenses	598	892	2,691	2,652
Capitalized G&A expenses	59	35	259	168
Total G&A expenses	657	927	2,950	2,820

Total G&A expenses in the fourth quarter fiscal 2023 were 29% lower than fiscal Q4 2022. The full year fiscal 2023 G&A expenses were 5% higher than the prior year. During the current fiscal year, the Company increased its general spending to support its 100% operated field development activities. These activities slowed during Q4 fiscal 2023 due to weather conditions, resulting in lower G&A expenses for the current quarter.

Share-based Compensation ("SBC")

($000s) **SBC**	Three months ended March 31		Twelve months ended March 31	
	2023	**2022**	**2023**	**2022**
Expensed share-based compensation	20	37	81	135
Capitalized share-based compensation	3	5	9	10
	23	42	90	145

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 lower in fiscal 2023 due fewer options granted during the year. At March 31, 2023, there were 10,920,000 outstanding options.

Depletion, Depreciation and Amortization (DD&A)

($000s) **DD&A**	**Three months ended March 31**		**Twelve months ended March 31**	
	2023	**2022**	**2023**	**2022**
Petroleum and natural gas properties	302	242	1,039	1,033
Other assets	-	1	3	4
Right-of-use assets	8	8	30	30
	310	251	1,072	1,067
DD&A - $/bbl	18.42	15.47	15.82	15.46

The Company's proved plus probable (2P) reserve volumes at March 31, 2023, decreased by approximately 301,000 bbls compared to March 31, 2022. In addition, future capital costs to develop 2P reserves at March 31, 2023, were $80.4 million compared to $61.5 million at March 31, 2022 due to inflationary pressures on current and expected future drilling costs.

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 2023 was 65,680 bbls compared to 66,797 bbls for the previous year contributing to a lower total depletion for fiscal 2022, which was offset by increased depletion rate associated with higher future development costs.

Impairment

($000s) **Impairment expense**	**Three months ended March 31**		**Twelve months ended March 31**	
	2023	**2022**	**2023**	**2022**
Exploration and evaluation assets	-	-	-	568
Petroleum and natural gas properties	-	-	-	-
	-	-	-	568

As at March 31, 2023, the Company concluded that there were no triggers for impairment on its Petroleum and Natural Gas properties and E&E assets. During 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 2023	2022	Twelve months ended March 31 2023	2022
Interest income	(5)	(7)	(18)	(7)
Accretion expense on decommissioning and restoration liability	29	15	164	38
Interest on lease liability	1	1	3	5
Interest – other	4	4	14	9
	29	13	163	45

Other Income

($000s) Other income	Three months ended March 31 2023	2022	Twelve months ended March 31 2023	2022
Other income	-	-	1,093	-
Other expenses	898	-	(898)	-
Other income - total	**(898)**	**-**	**195**	**-**

During Q4 fiscal 2023, Santos, the Cuisinier joint venture operator undertook a self-review with the Queensland Revenue Office relative to its royalty payments for the calendar years of 2015 through 2020. The result of this self-review was a $3.0 million additional royalty liability ($0.9 million net to Bengal) assessed to the Cuisinier Joint Venture. The net amount was recorded as an offset to other income for the quarter ended March 31, 2023. Santos is currently undertaking an independent review of their royalty obligations and Bengal is disputing these additional charges under its Joint Operating Agreement; however, the Company recorded the full net amount as an offset to other income for the quarter ended March 31, 2023.

During Q2 fiscal 2023, the Company resolved a historic crude oil stock discrepancy with the Cuisinier joint venture operator, which resulted in a net gain of $1.1 million after accruing associated royalties and is reflected as other income, which contributed to the current year's Funds from Operations and Cash from operations.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended March 31 2023	2022	Twelve months ended March 31 2023	2022
Geological and geophysical and workover	395	2,130	7,644	3,489
Drilling	-	16	23	591
Completions	-	(4)	48	240
Acquisition	-	-	-	-
Office	-	2	-	2
	395	2,144	7,715	4,322
Exploration and evaluation expenditures	60	588	2,227	1,231
Development and production expenditures	335	1,554	5,488	3,089
Office	-	2	-	2
	395	2,144	7,715	4,322

During the quarter ended March 31, 2023, the Company incurred $0.4 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. During the Company completed operations at Caracal-1, Wareena-1 and Wareena-5 as well as operational readiness activities associated with its 100% owned operations.

SHARE CAPITAL

Trading history	Three months ended March 31		Twelve months ended March 31	
	2023	2022	2023	2022
High ($)	0.09	0.12	0.14	0.14
Low ($)	0.06	0.06	0.05	0.06
Close ($)	0.06	0.12	0.06	0.12
Volume (000s)	761	2,962	4,424	11,255
Shares outstanding (000s)	485,304	485,304	485,304	485,304
Weighted average shares outstanding (000s)				
- basic	485,304	446,938	486,169	436,427
- diluted				

At June 14 2023, there were 485,304,215 common shares issued and outstanding, together with 10,920,000 outstanding options.

LIQUIDITY RISK AND CAPITAL RESOURCES

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing, and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of trade and other payables and lease liability and amounted to $3.1 million at March 31, 2023 (March 31, 2022 - $3.2 million).

At March 31, 2023, the Company had a working capital deficit, which the Company defines as total current assets less total current liabilities excluding other obligations and current portion of decommissioning obligations, of $0.3 million, including cash and cash equivalents of $0.8 million, compared to working capital of $5.5 million at March 31, 2022.

The Company expects that its cashflows generated from operations will be sufficient to meet its ongoing operating and general expenses, however additional capital will be required to meet its future capital commitments and to fund planned capital projects.

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.

COMMITMENTS

The Queensland Government regulatory authority granted the Company 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 work program consists of 260 km2 of 3D seismic and up to three wells. In February 2023, the Company extended its ATP 732 permit and received a PCA over 343 km^2. This included additional work commitments related to both ATP 732 and PCA 332 as outlined below.

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

Permit	**Work Program**	**Obligation period ending**	**Estimated expenditure (net) (millions CA$)[1]**
ATP 934 – Onshore Australia	260 km^2 3D seismic and up to three wells	February 2027	8.1
ATP 732 – Onshore Australia	Geological and up to three wells	February 2029	6.9
PCA 332 – Onshore Australia	Initial Production testing	February 2029	3.9
	Extended Production testing	February 2035	3.4

(1) Translated at March 31, 2022 at an exchange rate of AUS$1.00 = CAD$0.9366.

At March 31, 2023, 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	79	79	-	-	-
Decommissioning and restoration	5,096	-	881	-	4,215
	5,175	79	881	-	4,215

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

SELECTED QUARTERLY INFORMATION

	31-Mar 2023	31-Dec 2022	30-Sep 2022	30-Jun 2022	31-Mar 2022	31-Dec 2021	30-Sep 2021	30-Jun 2021
Fiscal quarter ($000s)	Q4 2023	Q3 2023	Q2 2023	Q1 2023	Q4 2022	Q3 2022	Q2 2022	Q1 2022
Oil sales	1,954	1,597	2,135	2,463	2,374	1,845	1,884	1,547
Cash flows (used in) from operations	(704)	747	1,053	1,015	437	607	565	(774)
Funds from (used in) operations[1]	(431)	(35)	1,774	680	515	381	417	119
Per share – basic and diluted ($)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
Net (loss) income	(803)	354	1,471	390	217	(494)	85	(182)
Per share – basic and diluted ($)	(0.00)	0.00	0.00	0.00	0.00	(0.00)	0.00	(0.00)
Capital expenditures	395	1,725	2,186	3,418	2,074	1,392	649	137
Working capital[1]	(284)	541	2,270	2,698	5,548	2,943	3,961	4,218
Total assets	49,697	50,785	48,545	46,188	48,500	42,835	42,321	44,429
Shares outstanding (000s)	485,304	485,304	485,304	485,304	485,304	432,987	432,987	432,987
Operations:								
Oil volumes (bbls/d)	182	180	174	184	174	183	199	176
Operating netback[1] ($/bbl)	65.75	39.50	77.77	88.14	91.06	64.58	51.08	41.30

(1) See “Non-IFRS Measurements” on page 15 of this MD&A.

Production was relatively stable over the past eight quarters averaging 182 bopd despite 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. The Cuisinier water injection pilot appears to have arrested natural declines for the past two quarters. Ongoing volatility with a generally increasing trend in US

Brent prices from Q1 fiscal 2022 to Q2 fiscal 2023 resulted in a trend towards increased oil sales and operating netbacks. Net income, cashflow and funds from operations were impacted by other income from a Cuisinier crude oil stock adjustment in Q2 fiscal 2023 and other expense from a Cuisinier royalty adjustment in Q4 fiscal 2023. The impact of 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. Working capital[3] deficiency occurred during the current period as a result of the Cuisinier joint venture royalty adjustment described above.

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision 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, 2023 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.

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

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.

The 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.

(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. Additionally, 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:

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[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	
	2023	**2022**	**2023**	**2022**
Oil sales	1,954	2,374	8,149	7,650
Royalties	(155)	(142)	(596)	(459)
Operating expenses	(721)	(807)	(3,101)	(3,082)
Operating netback	1,078	1,425	4,452	4,109

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	
	2023	**2022**	**2023**	**2022**
Cash (used in) from operating activities	(702)	437	2,111	835
Changes in non-cash working capital	273	78	(123)	597
Funds (used in) from operations	(429)	515	1,988	1,432

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	
	2023	**2022**	**2023**	**2022**
($/bbl)				
Oil sales	119.18	151.72	124.07	114.53
Royalties	(9.45)	(9.08)	(9.07)	(6.87)
Operating expenses	(43.98)	(51.58)	(47.21)	(46.14)
Operating netback	65.75	91.06	67.79	61.52

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 carefully consider 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.

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 because 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 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 because 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 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 always fund its ongoing activities. From time to time, Bengal may require additional financing 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 because 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, state, 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;*
- *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.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE

James B. Howe (Chairman)
Robert D. Steele
W. B. (Bill) Wheeler

RESERVES COMMITTEE

Dr. Brian J. Moss (Chairman)
Peter Lansom
Robert D. Steele

COMPENSATION COMMITTEE

Dr. Brian J. Moss (Chairman)
Robert D. Steele
Peter Lansom

GOVERNANCE AND NOMINATING COMMITTEE

W.B. (Bill) Wheeler (Chairman)
Robert D. Steele
Jim Howe

HEALTH SAFETY AND ENVIRONMENT COMMITTEE

Peter Lansom (Chairman)
Robert D. Steele
Dr. Brian J. Moss

OFFICERS

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

STOCK EXCHANGE LISTING – TSX: BNG

Consolidated Financial Statements

Years Ended
March 31, 2023, and 2022

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, 2023. 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
www.kpmg.ca

INDEPENDENT AUDITOR'S 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, 2023 and March 31, 2022
- the consolidated statements of income (loss) and comprehensive 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 statements of financial position of the Company as at March 31, 2023 and March 31, 2022, 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 **"*Auditor's Responsibilities for the Audit of the Financial Statements*"** section of our auditor's 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, 2023. 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 auditor's report.

Assessment of the impact of estimated proved and probable oil and gas reserves on property, plant and equipment ("PP&E")

Description of the matter

We draw attention to note 3, note 4, and note 8 to the financial statements. The Company uses estimated proved and probable oil and gas reserves to deplete its petroleum and natural gas properties included in PP&E, to assess for indicators of impairment on the Company's cash generating unit ("CGU") and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU.

The Company has $34,629 thousand of PP&E as at March 31, 2023. The Company depletes its net carrying value of petroleum and natural gas properties using the unit-of-production method by reference to the ratio of production in the year to the related proved and probable oil and gas reserves, taking into account estimated future development costs necessary to bring those reserves into production. Depletion and depreciation expense on petroleum and natural gas properties was $1,039 thousand for the year ended March 31, 2023.

The estimate of proved and probable oil and gas reserves 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.

The Company engages independent third-party reserve engineers to evaluate the proved and probable oil and gas reserves.

Why the matter is a key audit matter

We identified the assessment of the impact of estimated proved and probable oil and gas reserves on PP&E as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves.

How the matter was addressed in the audit

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

We assessed the depletion and depreciation expense calculation for compliance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

With respect to the estimate of proved and probable oil and gas reserves:

- We evaluated the competence, capabilities and objectivity of the independent third-party reserves engineer engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third-party reserves engineers
- We compared the fiscal 2023 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 future 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 2023 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 auditor's 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 auditor's 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.

Auditor's 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 auditor's 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 auditor's 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 auditor's 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 auditor's 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 auditor's 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 auditor's report is David Yung.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
June 14, 2023

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2023	2022
Assets			
Current assets:			
Cash and cash equivalents	5	$ 795	$ 5,413
Trade and other receivables	6	1,085	2,646
Prepaid expenses and deposits		903	658
		2,783	8,717
Exploration and evaluation assets	7	12,248	10,352
Property, plant and equipment	8	34,666	29,508
Total assets		$ 49,697	$ 48,577
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	9	$ 3,035	$ 3,211
Current portion of lease liability		32	37
		3,067	3,248
Decommissioning and restoration liability	11	5,096	3,379
Lease liability		-	31
		8,163	6,658
Shareholders' equity:			
Share capital	12	118,796	118,796
Contributed surplus		8,103	8,015
Accumulated and other comprehensive loss		(2,254)	(1,078)
Deficit		(83,111)	(83,814)
		41,534	41,919
Total liabilities and shareholder's equity		$ 49,697	$ 48,577

Commitments (Note 22)

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes	2023	2022
Revenue			
Oil sales	14	$ 8,149	$ 7,650
Royalties		(596)	(459)
		7,553	7,191
Expenses			
General and administrative		2,691	2,652
Operating		3,101	3,082
Depletion and depreciation	8	1,072	1,067
Impairment	7	-	568
Share-based compensation		81	135
Loss (gain) on foreign exchange		(63)	16
		6,882	7,520
Other income			
Other income	15	(195)	-
Finance expense	18	163	45
Net income (loss)		703	(374)
Exchange differences on translation of foreign operations		(1,176)	(742)
Comprehensive loss		$ (473)	$ (1,116)
Income (loss) per share – basic & diluted	16	$ 0.00	$ (0.00)
Weighted average shares outstanding (000s) – basic	16	485,304	436,427
Weighted average shares outstanding (000s) – diluted	16	486,169	436,427

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,	2023	2022
Share capital		
Balance beginning of the year	$ 118,796	$ 114,636
Issuance of common shares for cash	-	4,185
Share issue costs	-	(25)
Balance at end of year	118,796	118,796
Contributed surplus		
Balance at beginning of year	8,015	7,870
Share-based compensation – expensed	81	135
Share-based compensation – capitalized	7	10
Balance at end of year	8,103	8,015
Accumulated other comprehensive loss		
Balance at beginning of year	(1,078)	(336)
Exchange differences translation of foreign operations	(1,176)	(742)
Balance at end of year	(2,254)	(1,078)
Deficit		
Balance at beginning of year	(83,814)	(83,440)
Net income (loss)	703	(374)
Balance at end of year	(83,111)	(83,814)
Total shareholders' equity	$ 41,534	$ 41,919

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	2023	2022
Operating activities:			
Net income (loss) for the year		$ 703	$ (374)
Add (deduct) non-cash items			
Depletion and depreciation		1,072	1,067
Accretion on decommissioning and restoration liability	11	164	38
Share-based compensation		81	135
Interest on lease liability		3	5
Impairment	7	-	568
Unrealized foreign exchange gain		(35)	(7)
Funds from operations		1,988	1,432
Change in non-cash working capital	21	123	(597)
Net cash from operating activities		2,111	835
Investing activities:			
Exploration and evaluation expenditures	7	(2,227)	(1,231)
Petroleum and natural gas property and corporate expenditures	8	(5,488)	(3,091)
Change in restricted cash		-	40
Change in non-cash working capital	21	1,005	221
Net cash used in investing activities		(6,710)	(4,061)
Financing activities:			
Issuance of common shares, net of issuance costs	12	-	4,160
Repayment of credit facility		-	-
Lease payments		(40)	(36)
Net cash from financing activities		(40)	4,124
Net increase in cash and cash equivalents		(4,639)	898
Cash and cash equivalents, beginning of year		5,413	4,531
Impact of foreign exchange on cash and cash equivalents		21	(16)
Cash and cash equivalents, end of year		$795	$5,413

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, 2023 and 2022 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 14, 2023.

These financial statements have been prepared on a historical cost basis, except for decommissioning liabilities as discussed in Note 11.

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 matters 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 and financial reporting impact of compliance 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, 2023, 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.

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 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, trade and other receivables and trade and other payables.

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.

(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.

4. MANAGEMENT JUDGMENTS AND ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are out-lined below.

The 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.

(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, 2023**	**March 31, 2022**
Cash and bank balances	795	1,413
Short-term deposits	-	4,000
	795	5,413

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, 2023	March 31, 2022
Due from joint venture partners	1,076	2,635
Other receivables	9	11
	1,085	2,646

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

($000s)	
Balance, April 1, 2021	9,890
Additions	1,231
Impairment	(568)
Capitalized share-based compensation	4
Exchange adjustments	(205)
Balance, March 31, 2022	10,352
Additions	2,227
Capitalized share-based compensation	5
Exchange adjustments	(336)
Balance, March 31, 2023	12,248

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

($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

($000s)	
ATP 732P – Tookoonooka	7,565
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,546
ATP 934 – Barrolka	2,111
Other	26
Balance, March 31, 2023	12,248

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.

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

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, April 1, 2021	50,780	344	143	51,267
Additions	3,089	2	-	3,091
Capitalized share-based compensation	6			6
Disposals	-	-	-	-
Change in decommissioning and restoration liability	(59)	-	-	(59)
Exchange adjustments	(1,499)	-	-	(1,499)
Balance, March 31, 2022	52,317	346	143	52,806
Additions	5,486	2	-	5,488
Capitalized share-based compensation	2	-	-	2
Change in decommissioning and restoration liability	1,663	-	-	1,663
Exchange adjustments	(2,292)	(1)	-	(2,293)
Balance, March 31, 2023	57,176	347	143	57,666

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment losses:				
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
Depletion and depreciation	1,039	3	30	1,072
Exchange adjustments	(1,370)	-	-	(1,370)
Balance, March 31, 2023	22,547	332	121	23,000
($000s)				
Net carrying amount:				
At March 31, 2022	29,439	17	52	29,508
At March 31, 2023	34,629	15	22	34,666

At March 31, 2023 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 2023, the Company capitalized $0.1 million general and administrative expense (March 31, 2022 - $0.1 million). The calculation of depletion for the year ended March 31, 2023, included $80.4 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2022 - $61.5 million).

9. TRADE AND OTHER PAYABLES

($000s)	March 31, 2023	March 31, 2022
Trade payables	2,389	2,370
Accrued liabilities and other payables	646	841
	3,035	3,211

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	2023	2022
Income (loss) before taxes	703	(374)
Statutory tax rate	23.0%	23.5%
Expected income tax expense (recovery)	162	(88)
Change in enacted tax rates	-	-
Share-based compensation	19	41
Foreign exchange	7	6
Effect of tax rate in foreign jurisdiction	117	49
Other	21	780
Changes in unrecognized tax asset	(326)	(788)
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	**2023**	**2022**
Non-capital losses	37,710	45,618
Net capital losses	-	-
P&NG properties	12,779	8,669
	50,489	**54,287**

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

($000s)		
Year ended March 31	**2023**	**2022**
Property, plant and equipment	7,409	6,206
Fair value of financial instruments	-	-
Foreign exchange	913	1,331
Decommissioning obligations	(1,529)	(1,014)
Non-capital losses	(6,793)	(6,523)
	-	-

At March 31, 2023, the Company had approximately $35.6 million and $24.8 million of non-capital losses in Canada and Australia respectively (2022 - $38.9 million and $28.5 million, respectively), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2026, to 2043. 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, 2023, the Company has no deferred tax liabilities in respect of these temporary differences.

11. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2021	3,478
Change in estimate	(59)
Accretion	38
Exchange adjustments	(78)
Balance, March 31, 2022	3,379
Additions	-
Change in estimate	1,663
Accretion	164
Exchange adjustments	(110)
Balance, March 31, 2023	5,096

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, 2023 is approximately $3.7 million (March 31, 2022 – $3.4 million) which will be incurred between 2025 and 2060. An inflation factor of 6.50% (March 31, 2022 – 3.05%) and a risk-free discount rate of 3.50% (March 31, 2022 – 3.50%) have been applied to the decommissioning liability at March 31, 2023.

12. SHARE CAPITAL

Authorized:

Unlimited number of common shares with no par value.

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

Issued:

The following provides a continuity of share capital:

($000s)	**Number of common shares**	**Amount**
Balance at March 31, 2021	432,986,694	114,636
Share cancellation	(300)	-
Issuance of common shares for cash	52,317,821	4,160
Balance at March 31, 2022	485,304,215	118,796
Balance at March 31, 2023	485,304,215	118,796

13. SHARE-BASED COMPENSATION

The Company has a share option plan for directors, officers and employees of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of up to five years and vest one-third after the first year and one-third on each of the next two anniversary dates. The exercise price of each option equals the 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, 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
Granted	300,000	0.11
Expired	(1,825,000)	0.10
Balance, March 31, 2023	10,920,000	0.08
Exercisable, March 31, 2023	6,830,000	0.08

		Options Outstanding	**Options Exercisable**
Exercise Price	**Number Outstanding**	**Remaining Life (years)**	**Number Exercisable**
$0.11	300,000	2.98	-
$0.09	1,050,000	3.62	350,000
$0.08	9,570,000	4.30	6,380,000
	10,920,000	3.07	6,730,000

The fair value of the options granted during fiscal 2023 and 2022 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 2023	Fiscal 2022
Risk-free interest rate (%)	3.42	1.50
Expected life (years)	5	5
Expected volatility (%)[(1)]	122	119
Estimated forfeiture rate (%)	20	20
Weighted average fair value of options granted	\$0.08	\$0.07
Weighted average share price on date of grant	\$0.11	\$0.09

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

The fair value of the 300,000 stock options granted during fiscal 2023 was approximately \$25,000. The fair value of the 1,050,000 stock options granted during fiscal 2022 was approximately \$78,000.

14. REVENUE

Revenue from the sales of crude oil is based on the consideration specified in the Liquids Aggregation 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 Liquids Aggregation Agreement once the product is shipped to the end customer and lifted.

The transaction price as prescribed in the Liquids Aggregation 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. Revenues are typically collected 60 days following delivery to Port Bonython. Effective July 1, 2022, the Cuisinier Joint Venture negotiated a revised Liquids Aggregation Agreement with corresponding transportation agreements through to December 31, 2023.

15. OTHER INCOME

During the year, the Cuisinier JV was notified by the operator of a misallocation of sales revenue received in May 2020, at which time the purchasing party under the former Crude Oil Sales and Purchase Agreement had overallocated its purchase volumes to the Cuisinier Joint Venture, which resulted in a corresponding under reporting of crude oil stock inventory. In July of 2022, the Company received a net payment of \$1.1 million from the operator representing the difference between the historic pricing in May 2020 and current pricing on the additional crude oil stock which has been reflected as other income.

During Q4 fiscal 2023, Santos, the Cuisinier joint venture operator undertook a self-review with the Queensland Revenue Office relative to its royalty payments for the calendar years of 2015 through 2020. The result of this self-review was a \$3.0 million additional royalty liability (\$0.9 million net to Bengal) assessed to the Cuisinier Joint Venture. The net amount was recorded as and offset to other income for the quarter ended March 31, 2023. Santos is currently undertaking an independent review of their royalty obligations and Bengal is disputing these additional charges under its Joint Operating Agreement, however the Company recorded the full net amount as royalty expense for the quarter ended March 31, 2023.

16. 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	2023	2022
Net income (loss) for the year	703	(374)
Weighted average number of		
common shares basic (000s)	485,304	436,427
diluted (000s)	486,169	436,427
Basic and diluted (loss) income per share	$ 0.00	$ (0.00)

For the year ended March 31, 2023, there were 1,350,000 (March 31, 2022 – 12,445,000) options considered anti-dilutive.

17. 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	2023	2022
Salaries and employee benefits	782	666
Share-based compensation[1]	25	8
	807	674

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

18. FINANCE EXPENSE

($000s) Year ended March 31	2023	2022
Interest income	(18)	(7)
Accretion on decommissioning and restoration liability	164	38
Interest on lease liability	3	5
Interest on credit facility	-	-
Interest – other	14	9
	163	45

19. 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, 2023, Bengal's receivables consisted of $1.1 million (March 31, 2022 - $2.6 million) from joint venture partners (all of which has been collected subsequent to year end).

Bengal has a Liquids Aggregation 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, 2023 (March 31, 2022 - $nil). Past due is considered greater than 90 days outstanding.

Bengal did not provide any amounts for doubtful accounts during 2023 nor was it required to write-off any receivables during 2023.

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 $3.1 million at March 31, 2023 (March 31, 2022 - $3.2 million).

At March 31, 2023, the Company had a working capital deficit, which the Company defines as total current assets less total current liabilities excluding other obligations and current portion of decommissioning obligations, of $0.3 million, including cash and cash equivalents of $0.8 million, compared to working capital of $5.5 million at March 31, 2022. The Company expects that its cashflows generated from operations will be sufficient to meet its ongoing operating and general expenses, however additional capital will be required to meet its future capital commitments and to fund planned capital projects.

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.

(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, 2023:

($000s)	**CAD$**	**AUS$**	**US$**	**Total**
Cash and cash equivalents	176	33	586	795
Trade and other receivables	9	15	1,061	1,085
Trade and other payables	(221)	(2,813)	-	(3,035)
Lease liability	(32)	-	-	(32)
	(68)	(2,765)	1,647	(1,187)

Exchange rates as at March 31:	**2023**	**2022**
Number of CAD$ for 1 AUS$	0.90	0.94
Number of CAD$ for 1 US$	1.35	1.25

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. The Company had no commodity price derivatives at March 31, 2023 and 2022.

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, 2023 is restricted to investments with a maturity of three months or less. The Company had no interest rate derivatives at March 31, 2023 and 2022.

20. 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.

The Company manages its capital structure and make 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.

21. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s) Year ended March 31	2023	2022
Trade and other receivables	1,561	(1,422)
Prepaid expenses and deposits	(245)	(213)
Trade and other payables	(177)	1,272
Effect of change in foreign exchange rates	(11)	(13)
	1,128	(376)
Attributable to:		
Operating	123	(597)
Investing	1,005	221
Financing	-	-
	1,128	(376)

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

Cash interest paid and received ($000s) Year ended March 31	2023	2022
Cash interest paid	12	9
Cash interest received	18	7

22. 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 work program consists of 260 km2 of 3D seismic and up to three wells. In February 2023, the Company extended its ATP 732 permit and received a Potential Commercial Area ("PCA") over 343 km^2. This included additional work commitments related to both ATP 732 and PCA 332 as outlined below.

At March 31, 2023, the Company had the following capital work commitments:

Permit	Work Program	Obligation period ending	Estimated expenditure (net) (millions CA$)[1]
ATP 934 – Onshore Australia	260 km^2 3D seismic and up to three wells	February 2027	8.1
ATP 732 – Onshore Australia	Geological and up to three wells	February 2029	6.9
PCA 332 – Onshore Australia	Initial Production testing	February 2029	3.9
	Extended Production testing	February 2035	2.4

(1) Translated at March 31, 2023 at an exchange rate of AUS$1.00 = CAD$0.9062.

At March 31, 2023, 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	79	79	-	-	-
Decommissioning and restoration	5,096	-	881	-	4,215
	5,175	79	881	-	4,215

23. SEGMENTED INFORMATION

As at March 31, 2023, 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, 2023

	Australia	Corporate	Total
Revenue	8,149	-	8,149
Interest income	1	17	18
Interest expense	12	2	14
Depletion and depreciation	1,039	33	1,072
Impairment	-	-	-
Net income (loss)	1,647	(944)	703
Exploration and evaluation expenditures	2,227	-	2,227
Petroleum and natural gas property expenditures	5,488	-	5,488

($000s)
As at March 31, 2023

	Australia	Corporate	Total
Exploration and evaluation assets	12,248	-	12,248
Petroleum and natural gas properties	34,666	-	34,666
Total assets	49,440	257	49,697
Total liabilities	7,910	253	8,163

($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

CORPORATE INFORMATION

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LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE

James B. Howe (Chairman)
Robert D. Steele
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Dr. Brian J. Moss (Chairman)
Peter Lansom
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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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