International Exploration & Production

2021 Annual Report
Twelve Months Ended
March 31, 2021

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

During the fiscal year of 2021, Bengal Energy Ltd. ("Bengal" or the "Company") has transformed itself, despite the challenges associated with the COVID-19 global pandemic. Bengal achieved this by redeeming the Company's US$12.5 million reserves-based lending facility (the "credit facility") with Westpac Banking Corporation ("Westpac"), at a cost of US$10.0 million. This debt elimination has allowed Bengal Energy to turn the corner by making it debt-free. The transaction was financed through a CAD$16.5 million private placement of Bengal shares at a price of $0.05 per share, which after settlement of the credit facility, left CAD $4.0 million of free cash to support the Company's development plans. The subscription price for this private placement was valued at a 32% premium to the 5-day volume-weighted trading average of the Company's common shares on the TSX prior to the transaction announcement.

This is an exciting time for Bengal Energy Ltd. Bengal is now a changed company with a strong balance sheet and to complement this financial strength, several key events have been accomplished and more are scheduled to take place over the next twelve months. First, the Company closed significant additions to its wholly owned and controlled asset base surrounding an existing permit that is expected to support Bengal's long-term growth plans. Second, the Company added a farm-in partner to its prospective and high-impact exploration prospect, which will be drilled in Calendar Q4 2021 with the drilling cost fully carried by the farm-in partner; this drilling has the potential to be a game-changer for the Company. Third, Bengal has identified four wells from its recently acquired permits that will be tested and re-completed for production in its first phase of development. Fourth, Bengal has commenced a water injection pilot that is expected to increase production, cashflow and improve recovery over the life of our producing field in Cuisinier. And fifth, Bengal is excited about the drilling of our 3D seismic controlled Chef exploration prospect in the northeast corner of the Cuisinier permit, expected to commence in calendar Q4 2021. Further details of these forthcoming events are discussed below.

The Company's recently acquired PLs, while not currently producing, have existing wells indicating log pay, successful drill stem test ("DST") results and/or gas production from the Permian formation. Bengal has identified four wells to be tested and re-completed for production in its first phase of development. Specifically, this program is expected to include the following development activities; (a) recommissioning of a 26 km pipeline to tie a previously producing Wareena liquids-rich gas wells into a nearby compression station accessing the local Eastern Australian and export market; (b) work-over of the Ramses well that demonstrated both a Permian gas discovery and oil-zone completion in a cased well, which recovered 588 bbls/d of light crude oil, based on a 105-minute drill stem test. Upon completion of a successful test, this well is expected to be immediately equipped for production and the oil sold into the regional market; (c) work-over of the Ghina well to evaluate a previously drilled Permian liquids-rich gas discovery and assess the economics of tie-in and field recovery; and finally (d) twin drilling of the existing Karnak well that showed a liquids-rich gas pay zone in the Permian formation. Bengal expect that with the application of advanced underbalanced drilling techniques now commonplace in the Cooper Basin, a successful new well could be immediately tied into nearby gathering infrastructure.

The 100% ownership of these assets presents a significant appraisal and development opportunity that will be operated by the Company and is seen not only to be complementary to our proven producing, non-operated Cuisinier asset, but also as a key stepping stone for Bengal's natural gas platform with immediate market access to an existing pipeline upon which future exploration growth through ATP 934 can be undertaken.

Bengal has conducted extensive state-of-the-art geophysical work at ATP 934, which is over and above common practice in analogous fields in the Cooper Basin. The outcome of the additional analysis provides the Company with a higher degree of confidence in the block's identified features and has focused exploration on the most likely prospects. The farm-out of part of this block to Santos adds their extensive experience and expertise from recent exploration success in neighboring fields analogous to the joint venture's exploration targets. Santos will carry the drilling costs of one well to earn a 60% operated interest in the ATP 934 southern farm-out block, which represents 57.8% of the total block post April 2021 relinquishment. This well is currently scheduled for drilling in calendar Q4 2021 and if successful, Bengal would pay its 40% share of any well tie-in costs to nearby gathering infrastructure.

The completion of a water flood pilot at Cuisinier is particularly important due to the broad nature of the field's structure, which when combined with variable flank aquifer pressure support has resulted in pressure depletion at 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 continue planning its short and mid-term field recovery strategy. This includes a multi phase water injection scheme, targeted fracture stimulation and more commercially efficient development drilling. The Company is also eagerly anticipating participation in the 3D seismic controlled Chef exploration drilling project, which has been proposed by the Joint Venture operator (Santos) and is expected to commence in calendar Q4 2021. This target is in the northeast portion of the block which is immediately adjacent to the Cook and Cocinero fields also operated by Santos. This will be the Company's first well drilled into the Jurassic age reservoirs of the Birkhead-Hutton formations in this region of the permit which have proven to be prolific producers in the neighboring Cook and Cocinero fields.

Production for fiscal year ended March 31, 2021, averaged 221 barrels of oil per day, a decrease of 21% over fiscal 2020 due to natural production declines. Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2021 are 5,789 thousand barrels of oil ("Mbbls") and Proved reserves are 2,163 Mbbls. The net present value (NPV_{10}, before tax) of Bengal's 2P reserves are $87.6 million, or $0.21 per share. The 2P after tax net asset value is $69.1 million. The net present value (NPV10, before tax) of Bengal's Proved reserves are $33.5 million, or $0.08 per share. The Proved after tax net asset value is $30.4 million.

The Company remains active in identifying and analyzing additional production acquisition opportunities within our core areas in onshore Australia as well as the greater Asia Pacific region. Expanding our regions in which to consider potential acquisitions is done with the full intention to strategically add size and fund our strong growth initiatives in Australia. Our activities to date have positioned the Company well, setting the stage for near term growth and improved cash flow through an expanded acquisition strategy and a more robust development and exploration activity plan over the next several years. Although acquisition deal flow in Australia is generally thin, we have developed some important relationships and achieved significant headway during the year that may help us expand our position in both the oil and lucrative natural gas market in eastern Australia.

The near-term outlook for crude oil and natural gas prices in the Australian market has strengthened significantly from its abrupt collapse in March 2020 in the face of both the onset of the COVID-19 pandemic and the oil price war led by Saudi Arabia and Russia. Natural gas prices were also negatively affected due to the decreased demand for LNG exports to Asia and more gas being available for the domestic market. We are now encouraged by the medium-term bullish outlook for natural gas demand for eastern Australia and optimistic on the multiple egress and marketing opportunities available to optimize ATP 934 natural gas pricing and returns. The Australian east coast gas market is forecast to be undersupplied for the next 5-10 years and realized spot pricing was Australian $8.00 to $10.00 per Gigaoule ("GJ") during Calendar 2021 at the Wallumbilla sales point nearest to the Cooper basin.

During the past year, the Company has focused on creating a stable and flexible platform from which to drive sustainable growth and we are excited for the opportunity to deliver on this promise through a balanced mix of development, appraisal, and exploration projects during the coming year. Bengal recently posted two videos outlining impending activities and reasons for our excitement about the coming year; the videos can be found on our corporate website as shown by the links below:

https://bengalenergy.ca/wp-content/uploads/Bengal%20Presentation%20FINAL%202021.05.mp4

and

https://bengalenergy.ca/wp-content/uploads/2021/06/Bengal%20Energy%20June%202021.mp4

Shareholders may gain a more complete understanding of these developments by reading this note in conjunction with viewing the posted videos.

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, 2021 and 2020

Bengal
ENERGY LTD.

International Exploration & Production

Management's Discussion & Analysis

Three and Twelve Months Ended
March 31, 2021 and 2020

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Bengal Energy Ltd. ("Bengal" or the "Company") is at and for the three and twelve months ended March 31, 2021.

This MD&A dated June 17, 2021 should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2021 and 2020. 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 measures, abbreviations and forward-looking information relating to future events and the Company's future performance. Please refer to "Non-IFRS Measures", "Abbreviations" and "Advisories" sections at the end of this MD&A for further information.

Additional information relating to Bengal, including Bengal's audited March 31, 2021 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended March 31, 2021 may be referred to as "fourth quarter of fiscal 2021", "Q4 fiscal 2021" "Q4 FY 2021", "current quarter", and "the quarter". The comparative three months ended March 31, 2020, may be referred to as "fourth quarter of fiscal 2020", "Q4 fiscal 2020" "Q4 FY 2020", and "prior year's quarter". The year ended March 31, 2021, may be referred to as "fiscal 2021", "current year", and "the year". The comparative year ended March 31, 2020, may be referred to as "the previous year", "prior year", and "fiscal 2020".

FOURTH QUARTER FISCAL 2021 SUMMARY

Financial Summary:

- **Long term debt -** On February 26, 2021, the Company completed its debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac Banking Corporation ("Westpac") under its secured credit facility (the "Credit Facility") whereby the total balance outstanding of US$ 12.5 million was settled in exchange for a payment of US $10.0 million resulting in a gain on redemption of $3.5 million. In conjunction with this, the Company entered into a recapitalization transaction with Texada Capital Management Ltd. The transaction included the issuance of 330,720,000 common shares of the Company at a price of $0.05 per share for total proceeds of $16.5 million, of which $12.6 million (being the Canadian dollar equivalent of US $10.0 million based on the daily average CAD$/USD$ foreign exchange rate published by the Bank of Canada as at February 24, 2021) were used as settlement payment to Westpac.

- **Reserves –**Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2021 are 5,789 thousand barrels of oil ("Mbbls") and Proved reserves are 2,163 Mbbls. The net present value (NPV_{10}, before tax) of Bengal's 2P reserves are $87.6 million, or $0.21 per share. The 2P after tax net asset value is $69.1 million
- **Sales revenue** – Crude oil sales revenue was $1.6 million in the fourth quarter of fiscal 2021, which is 40% higher than the $1.1 million recorded in Q4 fiscal 2020. Full year fiscal 2021 sales revenue was $5.2 million compared to $8.1 million for the full year fiscal 2020. The decrease in sales revenue during the current fiscal year was due to a combination of naturally declining production volumes and lower realized crude oil prices, which continued to be impacted by demand disruptions associated with the ongoing COVID-19 pandemic.
- **Hedging** – The Company negotiated a waiver of all financial covenants and hedging requirements contemplated in its Credit Facility after December 31, 2020, therefore there were no realized or unrealized gains or losses on financial instruments during the quarter ended March 31, 2021. During the 2021 fiscal year, the Company recorded an unrealized loss of $1.5 million on its derivative contracts due to increasing crude oil prices. Upon settlement of the derivative contracts, the Company realized a $1.0 million gain on financial instruments which represents a 94% increase from the $0.5 million gain realized in the previous fiscal year.

- **Funds from (used in) operations**[1] – Bengal used $0.2 million of funds in operations during Q4 fiscal 2021 compared to $0.0 million of funds used in Q4 fiscal 2020. For the full year fiscal 2021, the Company generated and used $0.3 million of funds from operations compared to $0.4 million of funds from operations generated in the prior fiscal year. The decrease in funds from operations during fiscal 2021 was driven primarily by lower sales revenue as described above.
- **Net income** – Bengal reported a net income of $3.0 million for the current quarter compared to a net loss of $2.2 million in the fourth quarter of fiscal 2020. For the full year fiscal 2021, the Company reported $3.9 million of net income compared to a net loss of $2.9 million in the prior year. Several non-operational items contributed to net income during the year that were absent in the comparative period, including $3.7 million of foreign exchange gains and a $3.5 million gain on the settlement of the Company's Credit Facility.
- **Adjusted net income**[2] – Bengal reported an adjusted net loss of $0.4 million for the current quarter and $1.9 million for the full year fiscal 2021. Net income is adjusted for unrealized gain (loss) on financial instruments, the unrealized foreign exchange gain (loss) for the period and the non-cash impairment of non-current assets and $3.5 million gain on settlement of the Company's Credit Facility described above.

Operational Summary:

- **Production volumes** – The Company's share of total production in the current quarter was 18,222 bbls of light crude oil, which is a 21% decline from the 23,117 bbls produced in the fourth quarter of fiscal 2020. The current quarter production averaged 202 bbls/day compared to 254 bbls/day produced in the fourth quarter of fiscal 2020. Full year fiscal 2021 saw total production of 80,530 bbls compared to 102,230 bbls for full year fiscal 2020. The full year fiscal 2021 production per day averaged 221 bbls compared to 279 bbls/day for the full year fiscal 2020. During fiscal 2021, capital activity for the Cuisinier field was focused on the water injection pilot program, which is currently being commissioned and has not yet realized its expected incremental increase in production. Production, therefore, experienced natural reservoir decline rates through the year.
- **Capital expenditures** – Bengal completed the construction of its water injection pilot project during the fourth quarter of fiscal 2021. Due to the impacts of the COVID-19 pandemic on both commodity prices and operational capacity, the 2021 drilling campaign has been postponed until fiscal 2022.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

Bengal's producing and non-producing assets are situated in Australia's Cooper Basin, a region featuring large accumulations of very light and high quality crude oil and natural gas. The Company's core Australian assets, Petroleum Lease ("PL") 303 Cuisinier, ATP 934 Barrolka, ATP 732 Tookoonooka, and four recently acquired petroleum licenses are situated within an area of the Cooper Basin that is well served with production infrastructure and take-away capacity for produced crude oil and natural gas. Still in early stages in terms of appraisal and development, Bengal believes these assets offer attractive upside potential for both oil and gas. Australia presents a stable political, fiscal and economic environment in which to operate, and a favourable royalty regime for oil and gas production.

Under the State of Queensland Regulatory process, ATPs are granted by the State generally for a period of twelve years with one third of the original grant area expiring every four years. At the end of the final term of the ATP, an application can be made to continue a portion of the permit in the form of a PCA (Potential Commercial Area). PCAs have a life span of up to fifteen years. In the case of ATP 752, applications for PCAs 205 and 206 were made on the Barta block and approved by the Queensland regulatory authority based on: (a) the producing Cuisinier Oil Field offsetting and oil shows in the Murta zone; (b) the deeper Jurassic Birkhead zone in the Hudson 1, Koki 1 and Barta 1, which were previously drilled and abandoned, and (c) the evidence of structural continuity from the 3D seismic control acquired over the last few years. These applications include a commercial viability report that indicates the area is likely to be commercially viable within the applied term. This allows for extra time to commercialize the resource. A similar application was made and approved for PCA 155 on the Wompi block and approved. These PCA's remain a part of the ATP until expiry. If a discovery of oil or gas is made, an application for a petroleum lease is made to allow for production. PLs are granted for up to a thirty-year term. Bengal is a party to two PLs on the former ATP 752 Barta block, PL 303 and PL 1028, in addition to three PCAs, PCA 206, 207 Barta West and PCA 155 Wompi block-Nubba/Yilgarn. Bengal also acquired four PLs adjacent

[1] See "Non-IFRS Measurements" on page 16 of this MD&A
[2] See "Non-IFRS Measurements" on page 16 of this MD&A

to ATP 934 in Q2 FY 2020.

AUSTRALIA – Cooper Basin, Queensland

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

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

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

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned natural gas exploration block. Bengal conducted extensive state-of-the-art geophysical work over and above common practice in analogous fields in the Cooper Basin. The outcome of the additional analysis provides the Company with a higher degree of confidence in the block's identified features and has focused exploration on the most likely prospects.

Bengal entered into an agreement with Santos in July of 2020 to farm-in on a portion of the ATP 934 block. This farm-out finances and de-risks the initial field exploration by the basin leading gas explorer, with whom Bengal has an existing and successful partnership at the Cuisinier field. Additionally, and of equal importance, the partnership offers extensive operating experience backed by Santos' recent exploration success in neighboring fields analogous to the joint venture's exploration targets. Santos will carry the drilling costs of one well to earn a 60% operated interest in the ATP 934 southern farm-out block, which represents 57.8% of the total block post April 2020 relinquishment. This well is currently scheduled for drilling in calendar Q4 2021 and if successful, Bengal would pay its 40% share of any well tie in costs to nearby gathering infrastructure.

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

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

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

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

ATP 732 Tookoonooka (100% WI)

In June 2019, the Company applied for an amendment to the Later Work Program (LWP) for the third term of ATP 732 permit, On October 22, 2019, the Company received approval from the Queensland regulatory authority for an amended LWP for the third, four-year term commencing April 1, 2019 to March 31, 2023. The approved

LWP was revised to minimum activities of reprocessing seismic and inversion work with an estimated cost of $50K and geological and geophysical investigation at an estimated cost of $50K during the four-year term.

Using the extensive 2D and 3D seismic data the Company has acquired combined with the oil shows and oil recovery from the Caracal exploration well which was drilled and cased, the Company will be applying for a Potential Commercial Area ("PCA") over a part of the remaining ATP 732 land block. If successful, the PCA area will be exempt from further relinquishment.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback amounts)	**Three months ended March 31**				**Twelve months ended March 31**			
		2021		**2020**		**2021**		**2020**
Oil revenue	$	1,601	$	1,140	$	5,234	$	8,103
Operating netback[(1)]	$	670	$	249	$	2,754	$	4,547
Cash from operations	$	70	$	27	$	301	$	1,129
Funds (used in) from operations[(2)]	$	(158)	$	(849)	$	(305)	$	461
Per share ($) (basic and diluted)	$	0.00	$	(0.01)	$	0.00	$	0.00
Net income (loss)	$	3,040	$	(2,196)	$	3,928	$	(2,896)
Per share ($) (basic and diluted)	$	0.01	$	(0.02)	$	0.03	$	(0.03)
Adjusted net income (loss)[(3)]	$	(489)	$	(1,111)	$	(1,876)	$	(1,125)
Per share ($) (basic and diluted)	$	(0.01)	$	(0.01)	$	(0.01)	$	(0.01)
Capital expenditures	$	533	$	(68)	$	1,254	$	2,035
Oil volumes (bbl/d)		202		254		221		279
Operating netback [(1)]($/bbl)	$	36.77	$	10.77	$	34.20	$	44.47

(1) Operating netback is a non-IFRS measure and includes realized gain (loss) on financial instruments. Operating netback per bbl is calculated by dividing revenue (including realized gain (loss) on financial instruments) less royalties and operating costs by the total production of the Company measured in bbls. A reconciliation of the measures can be found on page 7 of this MD&A.

(2) Funds from (used in) operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and fiscal year. Funds from (used in) operations per share is a non-IFRS measure calculated as calculated by dividing funds from (used in) operations by weighted average basic and diluted shares outstanding for the periods disclosed. A reconciliation of the measures can be found in the table on page 16 of this MD&A.

(3) Adjusted net income (loss) and adjusted net income (loss) per share are non-IFRS measures. The comparable IFRS measure is net income (loss). A reconciliation of the two measures can be found in the table on page 16 of this MD&A.

(4) The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

RESULTS OF OPERATIONS

Production

	Three months ended March 31 2021	Three months ended March 31 2020	Twelve months ended March 31 2021	Twelve months ended March 31 2020
Oil production (bbls/d)	202	254	221	279
Oil production (bbls)	18,222	23,117	80,530	102,230

Production during the quarter and fiscal year ended March 31, 2021 decreased by approximately 21% compared to both fiscal Q4 2020 and the 2020 fiscal year. These decreases represent natural production declines at the Cuisinier field. In response to the uncertain commodity price environment of the past 12 months, all development activity at Cuisinier were deferred with the exception of the water injection pilot that is currently being finalized and has not yet added incremental production.

Revenue/Pricing

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

		Three months ended March 31 2021	Three months ended March 31 2020	Twelve months ended March 31 2021	Twelve months ended March 31 2020
	Oil lifting				
	Volume (000s bbls)	17.0	26.7	85.7	104.6
	Weighted average price ($US/bbl)	63.88	58.35	43.26	65.37
A.	Sales (CDN $000's)	1,390	2,337	5,028	9,378
	Pipeline oil				
	Volume (000s bbls), change	1.2	(3.5)	(4.7)	(2.40)
	Price ($US/bbl), change	9.90	(39.80)	39.56	(49.22)
B.	Net sales (CDN $000's)	211	(1,197)	206	(1,275)
A.+B.	Total oil sales (CDN $000s)	1,601	1,140	5,234	8,103

The price received for Bengal's Australian oil sales is benchmarked on US$ Brent for the month in which the bill of lading occurs, plus a realized premium due to oil quality differences. Pipeline oil is the term used to describe oil moving along the pipeline from the wellhead to the port that has been legally transferred to the buyer but not priced and waiting to be sold. Lifting occurs when the oil is moved from the port to the ship.

The COVID-19 pandemic and corresponding decrease in crude oil demand has significantly impacted benchmark crude oil pricing during fiscal 2021. During Q4 fiscal 2021 and to the date of this report, benchmark pricing has stabilized and accordingly the impact of pricing on Bengal's "pipeline oil" is less significant than in prior quarters based on consistence between quarter ending and quarter average pricing.

The following table outlines average benchmark prices:

	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Brent oil ($/bbl)	77.85	67.59	58.99	81.37
Brent oil (US$/bbl)	60.82	50.44	44.35	61.18
Number of CAD$ for 1 AUS$	0.99	0.88	0.95	0.91
Number of CAD$ for 1 US$	1.28	1.34	1.33	1.33

($000s)

Operating netbacks

	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Oil sales	1,601	1,140	5,234	8,103
Realized gain on financial instruments	-	268	1,033	533
Royalties	(96)	(259)	(314)	(316)
Operating expenses	(835)	(900)	(3,199)	(3,773)
Operating netback	670	249	2,754	4,547
($/bbl)				
Oil sales	87.86	49.31	64.99	79.26
Realized gain on financial instruments	-	11.59	12.83	5.21
Royalties	(5.27)	(11.20)	(3.90)	(3.09)
Operating expenses	(45.92)	(38.93)	(39.72)	(36.91)
Operating netback	36.77	10.77	34.20	44.47

In Q4 fiscal 2021, operating netbacks were $0.7 million or $36.77/bbl compared to Q4 fiscal 2020 at $0.2 million or $10.77/bbl. The primary reason for the 169% increase in operating netbacks is improved realized pricing on crude oil sales, which more than offset production declines. For the full year fiscal 2021, operating netbacks were $2.8 million or $34.20/bbl compared to $4.5 million or $44.47/bbl in the prior fiscal year due to lower realized crude oil sales prices and decreased production that were not fully offset by reduced operating expenses and the realized gain on financial instruments.

Risk Management Activities

The Company negotiated a waiver of all financial covenants and hedging requirements contemplated in its Credit Facility after December 31, 2020, therefore there were no realized or unrealized gains or losses on financial instruments during the quarter ended March 31, 2021. During the 2021 fiscal year, the Company realized a $1.0 million gain on financial instruments which represents a 94% increase from the $0.5 million gain realized in the previous fiscal year.

Royalties

Royalties

	Three months ended March 31		Twelve months ended March 31	
	2021	**2020**	**2021**	**2020**
Royalty expense ($000s)	96	259	314	316
$/bbl	5.27	11.20	3.90	3.09
% of revenue	6	23	6	4

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%.

Royalties have been calculated to be 6% of oil sales for full year fiscal 2021 as compared to 4% for the full year fiscal 2020 due to the application of allowable operating costs deductions and lower benchmark crude prices in the prior year. The significant decrease in royalty expense for the Q4 fiscal 2021 compared to Q4 fiscal 2020 is due to a year-to-date adjustment made by the operator during Q4 fiscal 2020 to reflect the annual fiscal 2020 royalty expense, for which there was no corresponding adjustment in the current quarter.

Operating Expenses

($000s)
Operating expenses

	Three months ended March 31		Twelve months ended March 31	
	2021	**2020**	**2021**	**2020**
Production	214	251	568	792
Transportation	621	649	2,631	2,981
	835	900	3,199	3,773
Production - $/bbl	11.74	10.86	7.05	7.75
Transportation - $/bbl	34.08	28.07	32.67	29.16
	45.82	38.93	39.72	36.91

Operating expenses for the three months ended March 31, 2021, were 18% higher than the previous year's fiscal Q4 on a per barrel basis. For the entire fiscal year, operating expenses per barrel were 8% higher than the prior year. The increase in relative operating expense is due to a combination of factors including progressively increasing water handling charges which are classified as transportation, the fixed nature of certain operating expenditures that have not decreased consistently with production and lack of joint venture audit credits as compared to prior years. Bengal is addressing water handling costs through its water injection program that will use produced water to support pressure in neighboring wells, which is expected to both increase production and decrease water handling charges. Following the easement of travel restrictions associated with the COVID-19 pandemic, the Company will commence joint venture audit activities, which based on historical experience, may result in operating expense credits associated with the preceding two fiscal years.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended March 31 2021	2020	Twelve months ended March 31 2021	2020
Net G&A expenses	843	806	2,341	3,589
Capitalized G&A expenses	-	153	(7)	(286)
Total G&A expenses	843	959	2,334	3,303

Total G&A expenses in the fourth quarter fiscal 2021 were 12% lower than fiscal Q4 2020. The full year fiscal 2021 G&A expenses were 29% lower than the prior year. The decrease in G&A expenses represents the Company's continued efforts to reduce all discretionary spending and focus free cashflows on accretive development opportunities. These reductions were supported by the Canadian Federal Government's wage and rent subsidy programs, which were in place for the entire fiscal year of 2021 and partially offset by several one-time severance payments during fiscal Q4 2021.

Share-based Compensation ("SBC")

($000s) SBC	Three months ended March 31 2021	2020	Twelve months ended March 31 2021	2020
Expensed share-based compensation	3	6	9	28
Capitalized share-based compensation	-	-	-	1
	3	6	9	29

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire five years from the grant date.

Depletion, Depreciation and Amortization (DD&A)

($000s) DD&A	Three months ended March 31 2021	2020	Twelve months ended March 31 2021	2020
Petroleum and natural gas properties	293	188	1,285	1,343
Other assets	1	2	6	7
Right-of-use assets	7	12	42	47
	301	202	1,333	1,397
DD&A - $/bbl	16.08	8.13	15.96	13.14

The Company's proved plus probable (2P) reserve volumes at March 31, 2021, decreased by approximately 65,000 bbls compared to March 31, 2020. In addition, capital costs to develop 2P reserves at March 31, 2021, were $60.9 million compared to $59.7 million at March 31, 2020.

The increase in depletion per barrel for Q4 fiscal 2021 compared to the comparative period is a result of a decrease in production of 18,222 bbls in Q4 fiscal 2021 compared with 23,117 bbls in Q4 fiscal 2020, coupled with an one-time adjustment in Q4 fiscal 2020 on depletion expense.

Production for full year fiscal 2021 was 102,230 bbls compared to 108,731 bbls for the previous year contributing to a lower total depletion for fiscal 2021.

Impairment

($000s) Impairment expense	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Exploration and evaluation assets	-	-	-	10
Petroleum and natural gas properties	-	626	-	636
	-	626	-	646

As at March 31, 2021, the Company concluded that there were no triggers for impairment on its E&E assets.

During Q4 fiscal 2020, the Company took an impairment charge of $0.6 million due to one development well, Cuisinier-27, deemed to be uneconomic following evaluation of the results of the five well drilling program.

Finance Expense

($000s) Finance expense	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Interest income	(1)	(2)	(1)	(4)
Accretion expense on decommissioning and restoration liability	5	8	19	34
Interest on lease liability	2	3	10	14
Interest on Credit Facility	136	272	881	1,232
	142	281	909	1,276

Interest on the Credit Facility had initially been based on US dollar LIBOR + 3% margin. The revised Credit Facility amendment dated November 2018 increased the margin to 3.75% effective January 1, 2019. An amendment to the Credit Facility dated November 2019 further increased the margin to 3.95% effective November 5, 2019. See details of the Credit Facility below. Interest on credit facility during fiscal Q4 2021 was accrued to February 26, 2021 at which time Company completed a debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac under its secured credit facility.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended March 31 2021	2020	Twelve months ended March 31 2021	2020
Geological and geophysical	63	62	196	263
Drilling	1	1	13	146
Completions	158	21	734	1,365
Acquisition	311	(152)	31	261
	533	(68)	1,254	2,035
Exploration and evaluation expenditures	61	-	61	22
Development and production expenditures	472	(68)	1,193	2,013
	533	(68)	1,254	2,035

The development and production expenditure of $1.3 million for the full year fiscal 2021 relates primarily to the water injection pilot program at the Cuisinier field. The $0.3 million of acquisition costs for the quarter ended March 31, 2021 represent closing costs associated with the Company's fiscal 2020 PL acquisitions billed in March 2021.

CREDIT FACILITY

On February 26, 2021, Company completed its debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac Banking Corporation ("Westpac") under its secured credit facility (the "Credit Facility") whereby the total balance outstanding of US$ 12.5 million was settled in exchange for a payment of US $10.0 million resulting in a gain on settlement of $3.5 million. In conjunction with this, the Company entered into a recapitalization transaction with Texada Capital Management Ltd. ("Texada"). The transaction included the issuance of 330,720,000 shares at a price of $0.05 per share for proceeds of $16.5 million, of which $12.6 million (corresponding to US $10.0 million at the transaction date) were used as settlement payment to Westpac.

SHARE CAPITAL

Trading history	Three months ended March 31 2021	2020	Twelve months ended March 31 2021	2020
High ($)	0.10	0.10	0.14	0.13
Low ($)	0.03	0.05	0.02	0.05
Close ($)	0.08	0.08	0.08	0.08
Volume (000s)	8,472	1,418	17,864	3,179
Shares outstanding (000s)	432,987	102,267	432,987	102,267
Weighted average shares outstanding (000s) - basic and diluted	227,205	102,267	133,073	102,267

At June 17, 2021, there were 432,986,694 common shares issued and outstanding, together with 13,716,667 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 $2.0 million at March 31, 2021 (March 31, 2020 - $18.9 million).

At March 31, 2021, the Company had working capital of $4.3 million, including cash and short-term deposits of $4.5 million and restricted cash of $0.04 million, compared to a working capital deficiency of $14.4 million at March 31, 2020. The prior year's working capital deficiency was primarily a result of the Credit Facility of $17.7 million maturing in February 2021.

In February 2021, the Company raised $16.5 million on the issuance of common shares and extinguished the Credit Facility. Management anticipates that operating and capital requirements will be met out of working capital and operating cash flows.

The majority of the Company's oil sales are benchmarked on US Brent prices. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of low crude oil prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside.

COMMITMENTS

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

At March 31, 2021, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2027	8.1(2)
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2021 at an exchange rate of AUS$1.00 = CAD$0.9578.

(2) The During fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced in exchange for a 50% relinquishment of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. During Q2 fiscal 2021, the Company entered into a farm-in agreement with Santos whereby Santos will pay 100% of the well costs of a one well work program with an estimated cost of AUS$2.7 million planned for the second half of calendar 2021. The $8.3 million of estimated expenditures is net of the estimated carried cost of AUS$2.7 million.

At March 31, 2021, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2021 to November 2054	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	278	97	181	-	-
Decommissioning and restoration	3,478	-	733	60	2,685
	3,756	97	914	60	2,685

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Mar 31 2021 **Q4 2021**	Dec 31 2020 Q3 2021	Sep 30 2020 Q2 2021	June 30 2020 Q1 2021	Mar 31 2020 Q4 2020	Dec 31 2019 Q3 2020	Sep 30 2019 Q2 2020	Jun 30 2019 Q1 2020
Oil sales	1,601	1,274	1,260	1,099	1,140	2,425	2,576	1,962
Cash flow from operations	70	62	(166)	335	27	259	527	316
Funds from (used in) operations(1)	(158)	130	(67)	(210)	(849)	599	724	(13)
Per share – basic and diluted ($)	0.00	0.00	(0.00)	0.00	(0.01)	0.01	0.01	0.00
Net income (loss)	3,040	670	(182)	400	(2,196)	556	(506)	(750)
Per share – basic and diluted ($)	0.01	0.01	(0.00)	0.00	(0.02)	0.01	(0.00)	(0.01)
Capital expenditures	533	498	124	99	(68)	346	477	1,280
Working capital (deficiency)	4,293	(15,068)	(15,129)	(14,908)	(14,434)	(13,823)	(14,120)	(13,964)
Total assets	44,246	41,914	41,138	41,097	39,572	41,391	40,849	40,373
Shares outstanding (000s)	432,987	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	202	211	231	238	254	280	333	249
Operating netback(1) ($/bbl)	36.77	42.37	27.15	31.60	10.77	59.68	53.78	49.01

(1) See “Non-IFRS Measurements” on page 16 of this MD&A.

Production over the last eight quarters peaked during the second quarter of fiscal 2020 (ended September 20, 2019) as all wells from the Company’s 2019 fracture stimulation program came on line. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since this peak. Significant volatility in benchmark crude pricing materially reduced oil sales in the four quarters preceding fiscal Q4 2021.

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at March 31, 2021 due to the material weaknesses noted below.

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

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

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

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

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board of Directors do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

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

(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, 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.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netbacks, netbacks per share, funds from (used in) operations, funds from (used in) operations per share, adjusted net income and adjusted net income per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Operating netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Operating netback per barrel equals netback divided by the applicable number of barrels. Management utilizes these measures for operational performance. Funds from (used in) operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. Funds from (used in) operations per share is a non-IFRS measure calculated as calculated by dividing funds from (used in) operations by weighted average basic and diluted shares outstanding for the periods disclosed Adjusted net income is a non-IFRS measure, which should not be considered an alternative to "Net income (loss)" as presented in the consolidated statement of income (loss) and comprehensive income (loss), and is presented in the Company's financial reports to assist management and investors in analyzing financial performance net of gains and losses outside of management's immediate control. Adjusted net income equals net income (loss) less unrealized gain (losses) on foreign exchange and unrealized gain (losses) on financial instruments plus non-cash impairment of non-current assets. Adjusted net income per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

Management believes the presentation of the non-IFRS measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

The following table reconciles cash from operations to funds from (used in) operations, which is used in this MD&A:

($000s)	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Cash from operating activities	70	27	301	1,127
Changes in non-cash working capital	(228)	(876)	(606)	(668)
Funds (used in) from operations	(158)	(849)	(305)	459

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

($000s)	Three months ended March 31 2021	Three months ended March 31 2020	Twelve months ended March 31 2021	Twelve months ended March 31 2020
Net income (loss)	3,040	(2,196)	3,928	(2,896)
Unrealized (gain) loss on financial instruments	-	(1,760)	1,539	(1,290)
Unrealized foreign exchange (gain) loss	(39)	2,219	(3,853)	2,415
Gain on settlement of long-term debt	(3,490)	-	(3,490)	-
Non-cash impairment of non-current assets	-	626	-	646
Adjusted net loss	(489)	(1,111)	(1,876)	(1,125)

ABBREVIATIONS

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

bbl	-	barrel
bbls	-	barrels
bbls/d	-	barrels per day
$/bbl	-	dollars per barrel
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
Santos		Santos Ltd.
WI	-	working interest
YTD	-	year to date

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.

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

Risks Relating to the COVID-19 Pandemic

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

The Company is exposed to the risks relating to public health emergencies, including COVID-19, and related government responses which may have a material and adverse effect on the Company's business, financial condition and operations. The extent to which COVID-19 may impact the Company's business is uncertain and not currently determinable. In the event that the prevalence of COVID-19 continues to increase, governments may enact further measures or extend existing measures impacting the Company's operations, suppliers, customers, counterparties, shippers, partners, employee health, the availability and function of regulatory agencies, or the flow of labour`. The Company continues to monitor and is taking precautions to adhere to all applicable occupational health guidelines and all recommendations from applicable government agencies and public health authorities. Such measures and mandates may also increase the Company's expenses.

The duration and continued severity of the COVID-19 pandemic is uncertain, and may continue for a significant period of time.

Exploration, Development and Production Risks

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

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

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

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

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

Risks Associated with Foreign Operations

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

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

Substantial Capital Requirements and Liquidity

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

Bengal monitors and updates its cash projection models on a regular basis, which assists in the timing decision of capital expenditures. Farm outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that Bengal wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal's capital program.

Health, Safety and Environment

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

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

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;*
- *Pipeline oil volume, sales and price estimates;*
- *The size of the oil and natural gas reserves;*
- *Bengal's drilling program and waterflood pilot;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *The expected timing of restarting the 2020 multi-well development and appraisal drilling campaign;*
- *The expected timing of the pilot reservoir maintenance scheme at the Cuisinier 24 well and the anticipated production increases resulting from the injection of produced formation water and future water flood expansion phases;*
- *The planned extended production tests on the Nubba gas discovery well and expected timing of tying in the well*
- *The expectation of placing the appropriate hedges on the Company’s production;*
- *The expected timing of the commencement of a pilot pressure maintenance scheme and the potential positive performance response of in the Cuisinier field;*
- *The timing of he extended production test on the Nubba gas discovery well on the Wompi block;*
- *The timing of the completion of the depth image processing completion on ATP 934;*
- *The possibility and timing of a third party farm in agreement on ATP 934 Barrolka;*
- *The possibility of additional reprocessing and acquisition of 2D and 3D seismic on ATP 934;*
- *Projections of market prices and costs including, but not limited to, expected royalty rates;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *That required payments will be met out of operation cash flows and alternative forms of financing;*
- *Expectations regarding the Credit Facility and the results of discussions with Westpac;*
- *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;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures, share issuances or other alternative forms of capital raising and funds will be sufficient to meet requirements including but not limited to Bengal’s exploration activities through fiscal 2020 and capital program;*
- *Anticipated adverse impacts on the Company's operating results, liquidity and financial position as a result of the current economic climate, and the expected persistence of depressed revenue and cash flow through 2021;*
- *Expectations that a firm agreement will be executed with a third party with an interest in farming-in on a portion of the ATP 934 block;*
- *The anticipated commercial viability of certain areas of the Barta block;*
- *The Company's plans to target future foreign operations in jurisdictions with known long-term oil and gas ventures; and*
- *The continued integration of subsurface data to select drilling locations.*

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause Bengal’s actual results, performance or achievement to differ materially from those expectations expressed in, or implied by, these forward-looking statements, including but not limited to, risks associated with:

- *Fluctuations in commodity prices, foreign exchange or interest rates;*
- *Uncertainties associated with the COVID-19 pandemic;*
- *Changes in the demand for or supply of Bengal's products;*
- *Liabilities inherent in oil and natural gas operations;*
- *The failure to obtain required regulatory approvals or extensions;*
- *The failure to satisfy the conditions under farm-in and joint venture agreements;*
- *The failure to secure required equipment and personnel;*
- *Changes in general global economic conditions including, without limitations, the economic conditions in North America and Australia;*

- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Increased competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *The availability of qualified operating or management personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Inability to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Bengal's development and exploration opportunities;*
- *The results of exploration and development drilling and related activities;*
- *Changes in laws and regulations including, without limitation, the adoption of new environmental, royalty and tax laws and regulations and changes in how they are interpreted and enforced;*
- *The ability to access sufficient capital from internal and external sources; and*
- *Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.*

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, which the resources and reserves described, can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Bengal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. Additional information on these and other factors that could affect Bengal's operations and financial results are included in reports on file with Canadian securities authorities and may be accessed through the SEDAR website (www.sedar.com) and at Bengal's website (www.bengalenergy.ca).

Disclosure of Oil and Gas Information

Unless otherwise specified, reserves data set forth in this document is based upon an independent reserve assessment and evaluation prepared by GLJ with an effective date of March 31, 2020 (the "GLJ Report"). The GLJ Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and the reserve definitions contained in National Instrument 51-101 – Standards of Disclosure For Oil and Gas Activities ("NI 51-101").

This document 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 section 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.

Internal Estimates

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

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE

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

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Dr. Brian J. Moss
Ian J. Towers

GOVERNANCE AND COMPENSATION COMMITTEE

Peter D. Gaffney
Dr. Brian J. Moss
Robert D. Steele (Chairman)
Ian J. Towers

OFFICERS

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

STOCK EXCHANGE LISTING – TSX: BNG

Consolidated Financial Statements

Years Ended
March 31, 2021 and 2020

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 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, 2021. 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"	*(signed) "Jerrad Blanchard"*
Chayan Chakrabarty	Jerrad Blanchard
President & Chief Executive Officer	Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bengal Energy Ltd.

Opinion

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

- the consolidated statements of financial position as at March 31, 2021 and March 31, 2020
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

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

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at March 31, 2021 and March 31, 2020, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

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

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

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

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended March 31, 2021. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

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

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

Description of the matter

We draw attention to notes 3 (f), 4 (a), 4 (b) and 8 to the financial statements. The Company assesses at each reporting date whether there is an indication that petroleum and natural gas properties within the Cuisinier cash generating unit (the "Cuisinier CGU") may be impaired. The Company determined that there were no external or internal indicators of impairment at March 31, 2021 for the Cuisinier CGU and no impairment tests were required. Significant management judgment is required to analyze the relevant external and internal indicators of impairment with the estimate of proved and probable oil and gas reserves and the related cash flows being significant to the assessment.

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

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

The Company engages an independent third party reserve engineer to estimate the proved and probable oil and gas reserves and the related cash flows as at March 31, 2021.

Why the matter is a key audit matter

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

How the matter was addressed in the audit

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

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

With respect to the estimate of proved and probable oil and gas reserves and the related cash flows as at March 31, 2021:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve engineer engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third party reserve engineers
- We compared the fiscal 2021 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves and the related cash flows to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to fiscal 2021 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

Other Information

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

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

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

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

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

We have nothing to report in this regard.

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

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

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

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

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

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

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

We also:

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

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

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

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

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
June 17, 2021

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2021	2020
Assets			
Current assets:			
Cash and cash equivalents	5	$ 4,531	$ 998
Restricted cash		40	140
Trade and other receivables	6	1,224	1,639
Prepaid expenses and deposits		445	126
Fair value of financial instruments		-	1,477
		6,240	4,350
Exploration and evaluation assets	7	9,890	8,930
Property, plant and equipment	8	28,116	26,292
Total assets		$ 44,246	$ 39,572
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	9	$ 1,939	$ 1,041
Current portion of credit facility	11	-	17,695
Current portion of lease liability	12	31	48
		1,970	18,748
Decommissioning and restoration liability	13	3,478	3,690
Lease liability	12	68	156
		5,516	22,630
Shareholders' equity:			
Share capital	14	114,636	98,100
Contributed surplus		7,870	7,861
Accumulated and other comprehensive loss		(336)	(1,651)
Deficit		(83,440)	(87,368)
		38,730	16,942
Total liabilities and shareholder's equity		$ 44,246	$ 39,572

Commitments (Note 23)

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

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

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes	2021	2020
Revenue			
Oil sales	16	$ 5,234	$ 8,103
Royalties		(314)	(316)
		4,920	7,787
Realized gain on financial instruments	20	1,033	533
Unrealized (loss) gain on financial instruments	20	(1,539)	1,290
		4,414	9,610
Expenses			
General and administrative		2,334	3,303
Operating		3,199	3,773
Depletion and depreciation	8	1,333	1,397
Impairment	7,8	-	646
Share-based compensation		9	28
(Gain) loss on foreign exchange		(3,694)	2,304
		3,181	11,451
Other (income) expense			
Gain on settlement of long-term debt	11	(3,490)	-
Other		(114)	(221)
Finance expense	19	909	1,276
Net income (loss)		3,928	(2,896)
Exchange differences on translation of foreign operations		1,315	(1,647)
Comprehensive income (loss)		$ 5,243	$ (4,543)
Income (loss) per share – basic & diluted	17	$ 0.03	$ (0.03)
Weighted average shares outstanding (000s) – basic & diluted	17	133,073	102,267

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)

For the years ended March 31,	2021	2020
Share capital		
Balance beginning of the year	$ 98,100	$ 98,100
Issuance of common shares for cash	16,536	-
Balance at end of year	114,636	98,100
Contributed surplus		
Balance at beginning of year	7,861	7,832
Share-based compensation - expensed	9	28
Share-based compensation – capitalized	-	1
Balance at end of year	7,870	7,861
Accumulated other comprehensive loss		
Balance at beginning of year	(1,651)	(4)
Exchange differences translation of foreign operations	1,315	(1,647)
Balance end of year	336	1,651
Deficit		
Balance at beginning of year	(87,368)	(84,472)
Net income (loss)	3,928	(2,896)
Balance at end of year	(83,440)	(87,368)
Total shareholders' equity	$ 38,730	$ 16,942

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the years ended March 31,	Notes	2021	2020
Operating activities:			
Net income (loss) for the year		$ 3,928	$ (2,896)
Add (deduct) non-cash items			
Depletion and depreciation		1,333	1,397
Accretion on decommissioning and restoration liability		19	34
Accretion on credit facility		215	301
Gain on asset sale and other		(15)	(221)
Gain on settlement of credit facility	11	(3,490)	-
Share-based compensation		9	28
Interest on lease liability		10	14
Lease incentive		-	31
Impairment		-	646
Unrealized loss (gain) on financial instruments		1,539	(1,290)
Unrealized foreign exchange (gain) loss		(3,853)	2,415
Funds (used in) from operations		(305)	459
Change in non-cash working capital	22	606	668
Net cash from operating activities		301	1,127
Investing activities:			
Exploration and evaluation expenditures	7	(61)	(22)
Petroleum and natural gas property expenditures	8	(1,193)	(2,013)
Proceeds on asset sale		-	221
Change in restricted cash		100	-
Change in non-cash working capital	21	474	(947)
Net cash used in investing activities		(680)	(2,761)
Financing activities:			
Issuance of common shares	14	16,536	-
Repayment of credit facility	11	(12,649)	-
Facility extension fees	11	-	(98)
Lease payments	12	(53)	(60)
Change in non-cash working capital	22	(6)	(2)
Net cash from (used in) financing activities		3,828	(160)
Net increase (decrease) in cash and cash equivalents		3,449	(1,794)
Cash and cash equivalents, beginning of year		998	2,891
Impact of foreign exchange on cash and cash equivalents		84	(99)
Cash and cash equivalents, end of year		$ 4,531	$ 998

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, 2021 and 2020 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 17, 2021.

These financial statements have been prepared on a historical cost basis, except for commodity contracts as discussed in Note 20.

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

3. 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, 2021, the Company has one producing CGU, the Cuisinier field located in Australia, in the Cooper Basin.

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

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

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

Financial assets

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

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

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

All impairment losses are recognized in profit or loss.

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

(g) Financial instruments

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

i. Classification and measurement of financial assets:

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

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

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

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

On initial recognition of an equity investment that is not held for trading, the Partnership 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.

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

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

iv. Share capital

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

(h) Foreign currency translation

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

(i) Share-based compensation

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

(j) Revenue recognition

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

Revenue from the sales of crude oil is based on the consideration specified in the Crude Oil Sales and Purchase Agreement ("COSP Agreement") with the joint venture operator. The Company recognizes revenue when it transfers control of the product to the joint venture operator, which is generally at the time the joint venture operator obtains legal title of the crude oil and when it is physically delivered to the pipeline at an estimated transaction price based on average US Brent price and is adjusted for quality and other factors specified in the COSP Agreement once the product is shipped to the end customer and lifted.

(k) Per share amounts

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

(l) Income taxes

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

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

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

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

(m) Finance income and expenses

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

(n) Determination of fair value

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

Fair Value Hierarchy

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

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

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

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

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

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

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

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

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

ii) Credit facility

The fair value of the Company's credit facility approximates its carrying value as it bears interest at floating rates and the applicable margin is indicative of the Company's current credit risk.

iii) Derivatives

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

(o) Leases

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

(p) **Government grants**

Government grants related to assets are initially recognized by the Company as deferred income at fair value if there is reasonable assurance that they will be received and the Company will comply with the conditions associated with the grant; they are then recognized in profit or loss as other income on a systematic basis over the useful life of the asset. Grants that compensate the Company for expenses incurred are recognized in profit or loss on a systematic basis in the periods in which the expenses are recognized. During year ended March 31, 2021, the Company recognized $249,675 as a reduction to operating/administrative expenses related to the Canadian government wage and rental subsidy.

4. MANAGEMENT JUDGMENTS AND ESTIMATES

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

In March 2020, the World Health Organization declared a global pandemic related to COVID-19. As a result of the global pandemic, in addition to numerous other factors, global commodity prices have experienced abnormal volatility over the past 24 months. Governments worldwide, including those in Canada and Australia, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally resulting in economic instability. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The current challenging economic climate may have significant adverse impacts on the Company, including material declines in revenue and cash flows, and related impacts to working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows to meet the Company's current and future obligations. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time. Estimates and judgements made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

(a) Critical judgments in applying accounting policies

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

Identification of cash-generating units

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

Impairment indicators

The Company assesses at each reporting date whether there is an indication that petroleum and natural gas properties within the Cuisinier cash generating unit (the "Cuisinier CGU") may be impaired. Significant judgment is required to analyze the relevant external and internal indicators of impairment with the estimate of proved and probable and oil and gas reserves and the related cash flows being significant to the assessment. If any such indication exists, the asset's 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, 2021	March 31, 2020
Cash and bank balances	4,531	994
Short-term deposits	-	4
	4,531	998

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, 2021	March 31, 2020
Due from joint venture partners	1,206	1,628
Other receivables	18	11
	1,224	1,639

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

($000s)	
Balance, April 1, 2019	9,711
Additions	22
Impairment	(10)
Exchange adjustments	(793)
Balance, March 31, 2020	8,930
Additions	61
Exchange adjustments	899
Balance, March 31, 2021	9,890

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

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

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

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, 2019	45,367	344	-	45,711
Additions	1,752	-	-	1,752
Acquisition	1,798	-	-	1,798
Adoption of IFRS 16	-	-	219	219
Capitalized share-based compensation	1	-	-	1
Change in decommissioning and restoration liability	368	-	-	368
Exchange adjustments	(5,464)	-	-	(5,464)
Balance, March 31, 2020	43,822	344	219	44,385
Additions	1,193	-	-	1,193
Disposals	-	-	(76)	(76)
Change in decommissioning and restoration liability	(623)	-	-	(623)
Exchange adjustments	6,388	-	-	6,388
Balance, March 31, 2021	50,780	344	143	51,267

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment losses:				
Balance, April 1, 2019	18,937	312	-	19,249
Depletion and depreciation	1,343	7	47	1,397
Impairment	636	-	-	636
Exchange adjustments	(3,189)	-	-	(3,189)
Balance, March 31, 2020	17,727	319	47	18,093
Depletion and depreciation	1,285	6	42	1,333
Disposals	-	-	(28)	(28)
Exchange adjustments	3,753	-	-	3,753
Balance, March 31, 2021	22,765	325	61	23,151

($000s)				
Net carrying amount:				
At March 31, 2020	26,095	25	172	26,292
At March 31, 2021	28,015	19	82	28,116

At March 31, 2021, the Company determined that there were no external or internal indicators of impairment. As a result, no impairment testing was conducted. During fiscal 2021, the Company capitalized $nil million general and administrative expense (2020 - $0.3 million). The calculation of depletion for the year ended March 31, 2021 included $60.9 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2020 - $59.7 million).

The Company recorded an impairment charge of $0.6 million during fiscal 2020 due to uneconomic drilling results.

At March 31, 2020, the Company evaluated its petroleum and natural gas assets for external and internal indicators of impairment. Due to industry and market conditions, especially the decline in crude oil prices, the Company identified that impairment triggers were present at March 31, 2020. The Company performed an impairment test but no adjustment was required. The impairment test compared the carrying amount of the Cuisinier CGU to the FVLCD, which is classified as a level 3 fair value measurement, based on the net present value of after-tax cash flows from proved plus probable oil and gas reserves estimated by an independent reserve evaluator, discounted at 10% to 30% depending on the various categories of reserves.

The following forecasted oil and gas commodity prices were used at March 31, 2020:

Year	Exchange Rate USD/CAD	Brent Blend Crude Oil FOB North Sea Then Current USD/bbl
2020	0.727	38.64
2021	0.730	45.50
2022	0.735	52.50
2023	0.740	57.50
2024	0.745	62.50
2025	0.750	62.95
2026	0.750	64.13
2027	0.750	65.33
2028	0.750	66.56
2029	0.750	67.81
2030+	0.750	+2.0%/yr.

During fiscal 2020, the Company acquired four Petroleum Leases ("PLs"), for nominal cash consideration. The associated decommissioning and restoration liability is valued at $1.5 million and acquisition costs of $0.26 million. All four PLs are located adjacent to the Company's existing gas exploration block ATP 934 in the Cooper Basin.

9. TRADE AND OTHER PAYABLES

($000s)	**March 31, 2021**	**March 31, 2020**
Trade payables	1,434	417
Accrued liabilities and other payables	505	624
	1,939	1,041

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	2021	2020
Loss before taxes	3,928	(2,896)
Statutory tax rate	23.5%	26%
Expected income tax recovery	923	(753)
Change in enacted tax rates	-	2,054
Share-based compensation	3	7
Foreign exchange	1,423	-
Effect of tax rate in foreign jurisdiction	325	(66)
Other	140	131
Changes in unrecognized tax asset	(2,814)	(1,373)
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	2021	2020
Non-capital losses	44,789	47,287
Net capital losses	5,983	5,092
P&NG properties	8,728	7,478
	59,500	59,857

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

($000s)		
Year ended March 31	**2021**	**2020**
Property, plant and equipment	5,763	5,114
Fair value of financial instruments	(5)	434
Foreign exchange	1,353	(1,559)
Decommissioning obligations	(1,043)	(1,107)
Non-capital losses	(6,068)	(2,897)
	-	-

At March 31, 2021, the Company had approximately $37.1 million and $27.9 million of non-capital losses in Canada and Australia respectively (2020 - $31.8 million and $25.2 million, respectively), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2026 to 2041. 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, 2021, the Company has no deferred tax liabilities in respect of these temporary differences.

On May 28, 2019, the Government of Alberta reduced the general corporate income tax rate to 8% (from 12%) over four years. Starting July 1, 2019, the general corporate tax rate decreased to 11% (from 12%), with further 1% rate reductions every year on January 1 until the general corporate tax rate is 8% on January 1, 2022, which results in a combined Canadian federal and provincial income tax rate of 23.5%.

11. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(2,160)
	12,210
Facility extension fees	(325)
Unrealized foreign exchange loss	4,274
Accretion	1,536
Balance, March 31, 2020	17,695
Unrealized foreign exchange loss	(1,770)
Repayment	(12,649)
Gain on settlement	(3,490)
Accretion	214
Balance, March 31, 2021	-

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

12. LEASE LIABILITY

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

($000s)	
Balance, March 31, 2019	-
IFRS 16 transition adjustment (Note 3)	250
Interest	14
Payments	(60)
Balance, March 31, 2020	204
Interest	10
Payments	(53)
Right-of-use adjustment	(62)
Balance, March 31, 2021	99
Current portion of lease liability	(31)
Non-current portion of lease liability	68

13. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2019	1,977
Change in estimate	368
Acquisition (Note 9)	1,538
Accretion	34
Exchange adjustments	(227)
Balance, March 31, 2020	3,690
Change in estimate	(623)
Accretion	19
Exchange adjustments	392
Balance, March 31, 2021	3,478

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation-adjusted undiscounted amount of cash flows required to settle its decommissioning and restoration costs at March 31, 2021 is approximately $4.1 million (March 31, 2020 – $4.0 million) which will be incurred between 2023 and 2057. An inflation factor of 1.1% (March 31, 2020 – 1.73%) and a risk-free discount rate of 1.74% (March 31, 2020 – 0.77%) have been applied to the decommissioning liability at March 31, 2021.

14. SHARE CAPITAL

Authorized:

Unlimited number of common shares with no par value.

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

Issued:

The following provides a continuity of share capital:

($000s)	**Number of common shares**	**Amount**
Balance at March 31, 2020	102,266,694	98,100
Issuance of common shares for cash	330,720,000	16,536
Balance at March 31, 2021	432,986,694	114,636

On February 26, 2021 the Bengal issued 330,720,000 as part of a private placement transaction with Texada, which is controlled by Bill Wheeler who acts as a director of the Company. Following this transaction, Texada controls approximately 83% of the Company's outstanding shares.

15. SHARE-BASED COMPENSATION

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

The Company accounts for its share-based compensation plan using the fair value method. Under this method, each grant results in three instalments. The fair value of the first instalment is charged to profit or loss over the first year. The remaining two instalments are charged to profit or loss over two and three years respectively.

Stock options granted under the plan can be exercised on a cashless basis, whereby the employee receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the employee so elects.

A summary of stock option activity is presented below:

	Options	Weighted average exercise price
		$
Balance, March 31, 2019	4,102,500	0.12
Expired	(152,201)	0.11
Forfeited	(477,799)	0.12
Balance, March 31, 2020	3,472,500	0.12
Granted	11,340,000	0.08
Expired	(1,012,500)	0.16
Forfeited	(83,333)	0.11
Balance, March 31, 2021	13,716,667	0.08
Exercisable, March 31, 2021	2,376,667	0.10

	Options Outstanding		Options Exercisable
Exercise Price	Number Outstanding	Remaining Life (years)	Number Exercisable
$0.10	2,185,000	1.25	2,185,000
$0.11	166,667	2.00	166,667
$0.125	25,000	1.50	25,000
$0.08	11,340,000	5.00	-
	13,716,667	1.87	2,376,667

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

Assumptions:	
Risk-free interest rate (%)	1.00
Expected life (years)	5
Expected volatility (%)[(1)]	29
Estimated forfeiture rate (%)	20
Weighted average fair value of options granted	$0.02
Weighted average share price on date of grant	$0.08

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

The fair value of the 11,340,000 stock options granted during Q4 fiscal 2021 was approximately $200,000.

16. REVENUE

Revenue from the sales of crude oil is based on the consideration specified in the Crude Oil Sales and Purchase Agreement (“COSP Agreement”) with the joint venture operator. The Company recognizes revenue when it transfers control of the product to the joint venture operator, which is generally at the time the joint venture operator obtains legal title of the crude oil and when it is physically delivered to the pipeline at an estimated transaction price based on average US Brent price and is adjusted for quality and other factors specified in the COSP Agreement once the product is shipped to the end customer and lifted.

The transaction price as prescribed in the COSP Agreement is a variable price based on the benchmark US Brent commodity price index, and may be adjusted for quality, location, delivery method or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantity of crude oil transferred to the joint venture operator. The COSP Agreement has an initial term to March 31, 2022, whereby delivery takes place through the contract period. Revenues are typically collected 60 days following delivery to Port Bonython.

17. PER SHARE AMOUNTS

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

($000s except per share amounts)		
Year ended March 31	**2021**	**2020**
Net income (loss) for the year	3,928	(2,896)
Weighted average number of		
common shares – basic and diluted (000s)	133,073	102,267
Basic and diluted income (loss) per share	$0.03	$ (0.03)

For the year ended March 31, 2021, there were 13,716,667 (March 31, 2020 - 3,472,500) options considered anti-dilutive.

18. COMPENSATION OF KEY MANAGEMENT PERSONNEL

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

($000s)		
Year ended March 31	**2021**	**2020**
Salaries and employee benefits	706	838
Share-based compensation(1)	8	26
	714	864

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

19. FINANCE EXPENSE

($000s) Year ended March 31	2021	2020
Interest income	(1)	(4)
Accretion on decommissioning and restoration liability	19	34
Interest on lease liability	10	14
Interest on credit facility	881	1,232
	909	1,276

20. FINANCIAL RISK MANAGEMENT

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

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

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at March 31, 2021, Bengal's receivables consisted of $1.2 million (March 31, 2020 - $1.6 million) from joint venture partners (of which $0.4 million has been collected subsequent to year end) and $nil million (March 31, 2020 - $0.01 million) of other receivables.

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

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

The Company had no accounts considered past due at March 31, 2021 (March 31, 2020 - $nil). Past due is considered greater than 90 days outstanding.

The carrying amount of accounts receivable and cash and cash equivalents and fair value of financial instruments represents the maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at March 31, 2021 and did not provide for any doubtful accounts, nor was it required to write-off any receivables during the year ended March 31, 2021 (March 31, 2020 – $nil). Exposure to the carrying value of its financial instruments relates to the Company's commodity-based derivatives held by Westpac Banking Corporation. At March 31, 2021, there were no commodity-based derivatives outstanding.

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 $2.0 million at March 31, 2021 (March 31, 2020 - $18.9 million).

At March 31, 2021, the Company had working capital of $4.3 million, including cash and short-term deposits of $4.5 million and restricted cash of $0.04 million, compared to a working capital deficiency of $14.4 million at March 31, 2020. The working capital deficiency at March 31, 2020 was primarily a result of the credit facility of $17.7 million maturing in February 2021.

At March 31, 2020, the Company had significant capital spending commitments to be incurred by February 2021 on ATP 934P of $12.3 million. During fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced in exchange for a 50% relinquishment of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. Current commitments are $8.3 million over the next six years.

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

The majority of the Company's oil sales are benchmarked on US Brent prices. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of low crude prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside.

(c) Market risk

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

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives US dollars for Australian oil sales and incurs expenditures in Australian and Canadian currencies. The Company may enter into derivative foreign currency contracts in order to manage foreign currency risk, but has not done so to date.

The table below shows the Company's exposure in Canadian dollar equivalent to foreign currencies for its financial instruments at March 31, 2021:

($000s)	CAD$	AUS$	US$	Total
Cash and cash equivalents	3,973	14	544	4,531
Restricted cash	40	-	-	40
Trade and other receivables	18	1	1,205	1,224
Trade and other payables	(333)	(1,606)	-	(1,939)
Lease liability	(99)	-	-	(99)
	3,599	(1,591)	1,749	3,757

Exchange rates as at March 31:	2021	2020
Number of CAD$ for 1 AUS$	0.96	0.87
Number of CAD$ for 1 US$	1.26	1.42

Commodity Price Risk

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

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

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not exposed to interest rate risk on its cash and cash equivalents at March 31, 2021 as the funds are not invested in interest-bearing instruments. The Company had no interest rate derivatives at March 31, 2021.

21. CAPITAL MANAGEMENT

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

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

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

22. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s) Year ended March 31	2021	2020
Trade and other receivables	415	1,333
Prepaid expenses and deposits	(319)	10
Trade and other payables	898	(1,533)
Effect of change in foreign exchange rates	80	(91)
	1,074	(281)
Attributable to:		
Operating	606	668
Investing	474	(947)
Financing	(6)	(2)
	1,074	(281)

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

Cash interest paid and received ($000s) Year ended March 31	2021	2020
Cash interest paid	623	1,020
Cash interest received	1	4

23. COMMITMENTS

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

At March 31, 2021, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2027	8.3(2)
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2021 at an exchange rate of AUS$1.00 = CAD$0.9578.

(2) During fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced in exchange for a 50% relinquishment of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. During Q2 fiscal 2021, the Company entered into a farm-in agreement with Santos whereby Santos will pay 100% of the well costs of a one well work program with an estimated cost of AUS$2.7 million planned for the second half of calendar 2021. The $8.3 million of estimated expenditures is net of the estimated carried cost of AUS$2.7 million.

At March 31, 2021, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2021 to March 2054	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	278	97	181	-	-
Decommissioning and restoration	3,478	-	733	60	2,685
	3,756	97	914	60	2,685

24. SEGMENTED INFORMATION

As at March 31, 2021, 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, 2021	**Australia**	**Corporate**	**Total**
Revenue	5,234	-	5,234
Interest revenue	-	1	1
Interest expense	881	10	891
Depletion and depreciation	1,285	48	1,333
Net income (loss)	4,737	(809)	3,928
Exploration and evaluation expenditures	61	-	61
Petroleum and natural gas property expenditures	1,193	-	1,193
($000s)			
As at March 31, 2021			
Exploration and evaluation assets	9,890	-	9,890
Petroleum and natural gas properties	28,015	-	28,015
Total assets	40,084	4,162	44,246
Total liabilities	5,084	432	5,516

($000s)			
For the year ended March 31, 2020	**Australia**	**Corporate**	**Total**
Revenue	8,103	-	8,103
Interest revenue	3	1	4
Interest expense	1,232	14	1,246
Depletion and depreciation	1,343	54	1,397
Impairment	646	-	646
Net loss	(1,651)	(1,245)	(2,896)
Exploration and evaluation expenditures	22	-	22
Petroleum and natural gas property expenditures	2,013	-	2,013
($000s)			
As at March 31, 2020			
Exploration and evaluation assets	8,930	-	8,930
Petroleum and natural gas properties	26,095	-	26,095
Total assets	38,770	802	39,572
Total liabilities	22,224	406	22,630

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE

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

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Dr. Brian J. Moss
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GOVERNANCE AND COMPENSATION COMMITTEE

Peter D. Gaffney
Dr. Brian J. Moss
Robert D. Steele (Chairman)
Ian J. Towers

OFFICERS

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

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