International exploration & production

Management's Discussion & Analysis

Three and Twelve Months Ended
March 31, 2019 and 2018

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Bengal Energy Ltd. ("Bengal" or the "Company") is at and for the three months and twelve months ended March 31, 2019.

This MD&A dated June 20, 2019 should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2019 and 2018. The consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The functional currency of the Company's operating subsidiary 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, 2019 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended March 31, 2019 may be referred to as "fourth quarter fiscal 2019", "Q4 FY 2019", "current quarter", and "the quarter". The comparative three months ended March 31, 2018, may be referred to as "fourth quarter fiscal 2018", "Q4 FY 2018", "prior year's quarter", and "2018 quarter". The year ended March 31, 2019, may be referred to as "fiscal 2019", "current year", and "the year". The comparative year ended March 31, 2018, may be referred to as "the previous year", "prior year", and "fiscal 2018".

FOURTH QUARTER FISCAL 2019 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $2.7 million in the fourth quarter of fiscal 2019, which is 4% lower than the $2.8 million recorded in Q4 fiscal 2018. Full year fiscal 2019 sales revenue was $11.2 million compared to $10.7 million for the full year fiscal 2018. The improved full year performance in fiscal 2019 compared to fiscal 2018 was due primarily to an overall higher average US Brent price, despite a lower overall production volume.
- **Hedging** – The Company's Credit Facility requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. At year-end fiscal 2019, the realized loss on financial instruments was $1.2 million while an unrealized gain on financial instruments of $1.1 million was recorded. The quarter ended March 31, 2019 had hedges in place at US$55.40/bbl while the two subsequent quarters have a portion of expected production hedged at over US$72/bbl. For the quarter ending December 31, 2019, a portion of production has been hedged using puts and swaps at US$54.20/bbl. For the period Jan –March 2020, the hedging program has a combination of puts and swaps at US$63.74/bbl.
- **Funds from Operations** – Bengal generated funds from operations of $0.8 million during Q4 fiscal 2019 compared to $0.5 million of funds from operations in Q4 fiscal 2018. For the full year fiscal 2019, the Company generated funds from operations of $2.2 million, down from $3.7 million of funds from operations in fiscal 2018. The primary reason for the decrease in funds from operations during fiscal 2019 as compared to fiscal 2018 was the impact of the realized loss on financial instruments.
- **Net loss** – Bengal reported a net loss of $2.1 million for the current quarter compared to a net loss of $12.5 million in the fourth quarter of fiscal 2018. For the full year fiscal 2019, the Company reported a net loss of $2.5 million compared to fiscal 2018 net loss of $12.3 million. The primary driver for the net loss for both the current quarter and full year fiscal 2019 was an asset impairment of $1.9 million and $2.8 million respectively.
- **Adjusted Net Income –** Bengal reported adjusted net income of $0.4 million for the current quarter and $0.5 million for the full year fiscal 2019. 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.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 25,303 bbls, which is a 16% decline from the 30,050 bbls produced in the fourth quarter of fiscal 2018. The current quarter production averaged 281 bbls per day compared to 334 bbls per day produced in the fourth quarter of fiscal 2018. Full year fiscal 2019 saw total production of 108,731 compared to 131,455 for full year fiscal 2018. The full year fiscal 2019 production per day averaged 298 bbls compared to 360 bbls per day for the full year fiscal 2018. Normal production declines and reduced capital spending in time to realise any increase in production during the fiscal year, are the reason for the reduction in production for year over year.

- **Capital Expenditures** – Bengal commenced its five well development drilling program and capital expenditures towards the waterflood pilot in the fourth quarter of fiscal 2019. The drilling program completion is expected to occur by the end of Q2 fiscal 2020. The waterflood pilot will take place during second quarter of fiscal 2020. During Q4 fiscal 2019, Bengal incurred $2.4 million in capital expenditures related to this capital program. Full year fiscal 2019 saw total capital expenditure of $4.3 million, which included the exploration well drilling in Q2 fiscal 2019.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

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

Under the State of Queensland Regulatory process, ATPs (Authority's to Prospect) are granted by the State generally for a period of twelve years with one third of the original grant area expiring every four years. At the end of the final term of the ATP, an application can be made to continue a portion of the permit in the form of a PCA (Potential Commercial Area). PCAs have a life span of five to fifteen years. If a discovery of oil or gas is made an application for a PL, (Petroleum Lease) is made to allow for production. PLs are granted for up to a thirty-year term. Bengal now has two PLs for the Cuisinier field, PL 303 and PL 1028.

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

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

During the Q3 and Q4 fiscal 2019, the Company's joint venture on Barta Block Cuisinier PL 303 (the "Joint Venture") conducted a fracture stimulation campaign on four wells. Three of the four wells were successful and the Cuisinier North-1, Shefu-1 and Cuisinier-24 wells were brought online in September. The Cuisinier-19 well was fracture stimulated in a later program during Q3 fiscal 2019 but was unsuccessful. Prior to the frac program, the aggregate gross production from the three wells was 93 bbls/d. Subsequent to the frac program, the aggregate initial production was 322 bbls/d, for an incremental increase of 229 gross bbls/d (an incremental 69 bbls/d net to Bengal). These post frac rates have been monitored closely over the last quarter with positive productivity levels observed. Ongoing evaluation of previously stimulated wells has assisted the Joint Venture in planning for its future drilling campaigns. These campaigns are designed to allow for fracture stimulations to occur upon completion as required. This will result in operational efficiencies and cost savings in addition to potentially improved initial production rates on the stimulated wells.

The fiscal year 2019 drilling program consisting of four development wells and one appraisal well within PL 303 started in February 2019. Two of the four development wells, Cuisinier 29 and Cuisinier 30 were located on the northwest side of the Cuisinier pool close to production infrastructure and were designed to extend the producing area while potentially increasing the pool reserves area. The Cuisinier 29 well was successfully drilled, cased and suspended in late February and discovered a new oil pool in the DC-50 sand that lies below the target DC-70 zone. The DC-50 sand is approximately 12.5 metres thick with an estimated 6.9 metres of internally estimated net oil pay. In addition, the well intersected approximately 1.1 metres of internally estimated net oil pay in the target zone DC-70 sand, which also shows virgin pressure. The well has been cased and suspended as a future oil producer.

The Cuisinier-27 and 28 development wells were located in the heart of the Cuisinier pool offsetting the planned waterflood pilot. Both of these wells met pre-drill expectations encountering 4.1 and 4.6 metres of internally estimated net oil pay respectively. These wells have been cased and suspended as Murta DC-70 oil wells. The fourth development well, Cuisinier-30, encountered 7.2 metres of Murta DC-70 sand; however the zone was low and water bearing. This well was therefore plugged and abandoned.

The Cuisinier-26 appraisal well was drilled in the southernmost part of PL 303 and was intended to extend the known producing sand fairway present in the core of the pool. The well encountered 0.8 metres of internally estimated net oil pay in the Murta DC-70 and was plugged and abandoned as uneconomic. In calendar Q1 FY 2020, the three successful wells will be connected for production and an assessment of the productivity will be made. A development plan for the new DC-50 sand will be prepared based on initial production results. First oil sales from the new 2019 wells are expected in early calendar Q2 FY 2020. Results to date for the 2019 Cuisinier drilling campaign have been encouraging for further appraisal of the western extension of the Cuisinier oil field and particularly for the new zone in the Cuisinier 29 well. The program has shown a total of four oil reservoir zones that were encountered in three of the four development wells drilled. The new pool discovery in the DC-50 sand in the Cuisinier-29 well may provide further development drilling opportunities and pool expansion upside. Further results will be released upon program completion, which is anticipated to occur in early calendar Q2 FY 2020.

The Joint Venture has also initiated the implementation of a pilot reservoir pressure maintenance scheme, which is planned to commence during calendar Q2 FY 2020. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier-24 well. The broad nature of the Cuisinier structure combined with weak 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 generate a positive response in production performance of up to four offsetting producing wells. In addition, the planned program will also complement future water flood expansion phases currently in the initial planning stages.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned gas exploration block that was acquired in March 2015. Bengal's completion of seismic amplitude inversion studies have highlighted the most favourable areas of the permit allowing for additional detailed geophysical work. The reprocessing of select 2D seismic lines will be valuable in selection of future drilling locations and locating the area of potential 3D seismic acquisition in fiscal year 2021. In addition to inversion, the Company has also embarked on depth image processing to help mitigate the velocity impact of near surface velocity changes, known to affect the quality of the time to the depth conversion. This work is expected to be completed by the end of June 2019 and will further advance the de-risking of previously high graded prospect areas.

Bengal has consolidated its ownership to 100% working interest in the permit through the acquisition of the remaining non-owned interest and now has operatorship. Discussions are ongoing with third parties who may have an interest in farming in on this block, supporting the next phase of exploration thereby further de-risking the natural gas potential of the permit.

OPERATING SUMMARY

($000s except per share, %, volumes and netback amounts)	Three months ended March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Oil revenue	$ 2,667	$ 2,783	$ 11,211	$ 10,710
Operating netback[1]	$ 1,944	$ 1,282	$ 5,780	$ 6,918
Cash from operations	$ 635	$ 858	$ 2,691	$ 3,627
Funds from operations[2]	$ 842	$ 525	$ 2,220	$ 3,737
Per share ($) (basic and diluted)	$ 0.01	$ 0.01	$ 0.02	$ 0.04
Net loss	$ (2,144)	$ (12,526)	$ (2,475)	$ (12,271)
Per share ($) (basic and diluted)	$ (0.02)	$ (0.12)	$ (0.03)	$ (0.12)
Adjusted net income (loss)[3]	$ 397	$ (143)	$ 525	$ 1,459
Per share ($) (basic and diluted)	$ 0.00	$ 0.00	$ 0.01	$ 0.01
Capital expenditures	$ 2,473	$ 939	$ 4,346	$ 3,511
Oil volumes (bbl/d)	281	334	298	360
Netback[1]($/bbl)	$ 76.82	$ 42.66	$ 53.16	$ 52.63

(1) Operating netback is a non-IFRS measure and includes realized (loss) gain on financial instruments. 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 operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. Funds from operations per share is a non-IFRS measure calculated as calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed. A reconciliation of the measures can be found in the table on page 20 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 20 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		Twelve months ended March 31	
	2019	2018	2019	2018
Oil production (bbls/d)	281	334	298	360
Oil production (bbls)	25,303	30,050	108,731	131,455

Revenue/Pricing

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

		Three months ended March 31		Twelve months ended March 31	
		2019	2018	2019	2018
	Oil lifting				
	Volume (000s bbls)	27.2	31.4	119.7	134.1
	Weighted average price ($US/bbl)	66.18	70.45	73.83	60.76
	Sales ($US000's)	1,800	2,212	8,837	8,148
A.	Sales ($000's)	2,412	2,853	12,070	10,383
	Pipeline oil				
	Volume (000s bbls), change	(1.9)	(1.4)	(11.0)	(2.7)
	Price ($US/bbl), change	18.67	1.56	8.62	14.70
	Net sales ($US000's)	191	(54)	(633)	252
B.	Net sales ($000's)	255	(70)	(859)	327
A.+B.	**Total oil sales** ($000s)	2,667	2,783	11,211	10,710

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.

Realized crude oil price during Q4 fiscal 2019 was significantly impacted by the decline in US Brent as compared to Q4 fiscal 2018. The realized weighted average price of oil-lifting sales was US$ 66.18/bbl and US$70.45/bbl for Q4 FY 2019 and 2018 respectively. When combined with lower oil lifting volumes in Q4 fiscal 2019 of 27.2K bbls as compared to 31.4K bbls in Q4 fiscal 2018, oil-lifting sales were lower at $2.4 million for the current quarter as compared to $2.8 million for Q4 fiscal 2018. For the full year fiscal 2019, the realized weighted average price of oil-lifting sales was US$73.83/bbl as compared to US$60.76/bbl for the full year fiscal 2018 or 22% higher. Despite oil-lifting volumes being lower in fiscal 2019 at 119.7K bbls as compared to oil lifting volumes in fiscal 2018 at 134.1K bbls, or 11% lower, oil-lifting sales were higher in fiscal 2019 at $12.1 million compared to $10.4 million in fiscal 2018. When oil-lifting sales are adjusted for the change in value of the pipeline oil both for the current quarter of $0.3 million and full year fiscal 2019 of ($0.9 million), Bengal's total oil sales are $2.7 million for the current quarter and $11.2 million for the full year fiscal 2019.

The following table outlines average benchmark prices:

	Three months ended March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Brent oil ($/bbl)	84.02	86.61	91.90	74.23
Brent oil (US$/bbl)	63.17	66.81	70.15	57.57
Number of CAD$ for 1 AUS$	0.95	0.99	0.96	0.99
Number of CAD$ for 1 US$	1.33	1.26	1.31	1.28

($000s)

Operating Netbacks

	Three months ended March 31		Twelve months ended March 31	
	2019	**2018**	**2019**	**2018**
Oil sales	2,667	2,783	11,211	10,710
Realized (loss) gain on financial instruments	(90)	(288)	(1,236)	568
Royalties	(59)	(136)	(570)	(642)
Operating expenses	(574)	(1,077)	(3,625)	(3,718)
Operating Netback	1,944	1,282	5,780	6,918
($/bbl)				
Oil sales	105.40	92.61	103.11	81.47
Realized (loss) gain on financial instruments	(3.56)	(9.58)	(11.37)	4.32
Royalties	(2.33)	(4.53)	(5.24)	(4.88)
Operating expenses	(22.69)	(35.84)	(33.34)	(28.28)
Operating Netback	76.82	42.66	53.16	52.63

Netbacks in Q4 fiscal 2019 were $1.9 million or $76.82/bbl compared to Q4 fiscal 2018 at $1.3 million or $42.66/bbl. The primary reason for the increase in operating netbacks during the current quarter compared to Q4 fiscal 2018 was the realization of a $0.4 million credit due to Bengal as a result of an audit of our JV partner. This credit reduced the Q4 fiscal 2019 operating expenses by $13.67/ bbl. As a result of the credit, operating expenses for the current quarter were $22.69/bbl as compared to $35.84/bbl for Q4 fiscal 2018. For the full year fiscal 2019, netbacks were $5.8 million or $53.16/ bbl. The credit reduced the full year operating expenses by $3.18/bbl. The realized loss on financial instruments of $1.2 million is due to the US$ 47/bbl hedges throughout the nine months ended Q4 fiscal 2019. Royalties have been calculated to be 5.08% of oil sales for full year fiscal 2019 as compared to 6% for the full year fiscal 2018 due to increased capital expenditure in fiscal 2019. The reduced royalty expense in Q4 fiscal 2019 is due to an adjustment made during the current quarter, to reflect the annual fiscal 2019 reduced royalty expense. Comparative operating expenses for 2018 were much lower as a result of a significantly higher credit received from a Joint Venture audit. The impact of last years realized credit was $22.66/ bbl for Q4 fiscal 2018 and $5.18/ bbl for the full fiscal 2018.

Risk Management Activities

Bengal has entered into financial commodity contracts as part of its risk management program to manage commodity price fluctuations related to its primary producing assets being the Cuisinier field in Australia’s Cooper Basin. It is a requirement under Bengal’s Credit Facility to hedge 50% of its annual production.

With respect to financial contracts, which are derivative financial instruments, Management has elected not to use hedge accounting and consequently records the fair value of its crude oil financial contracts on the statement of financial position at each reporting period, with the change in fair value being classified as unrealized gains and losses in the consolidated statement of income (loss).

As at March 31, 2019, the Company has the following derivative contracts:

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
April 1, 2019 – April 30, 2019	Oil - swap	5,000	73.28	73.28
				-

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
May 1, 2019 – May 31, 2019	Oil - swap	5,000	72.92	72.92

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
June 1, 2019 – June 30, 2019	Oil - swap	5,000	72.92	72.92

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
July 1, 2019 – July 31, 2019	Oil - swap	5,000	75.03	75.03

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	60	-	60
Non-current fair value of financial instruments	-	-	-
	60	-	60

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
August 1, 2019 – August 31, 2019	Oil - swap	5,000	74.69	74.69

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	58	-	58
Non-current fair value of financial instruments	-	-	-
	58	-	58

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
September 1, 2019 – September 30, 2019	Oil - swap	5,000	74.37	74.37

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	57	-	57
Non-current fair value of financial instruments	-	-	-
	57	-	57

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
October 1, 2019 – December 31, 2019	Oil - swap	7,500	54.20	54.20
October 1, 2019 – December 31, 2019	Oil – put option	7,500	54.20	-

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(113)	18	(95)
Non-current fair value of financial instruments	-	-	-
	(113)	18	(95)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
January 1, 2020 – March 31, 2020	Oil - swap	15,000	63.74	63.74

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(26)	-	(26)
Non-current fair value of financial instruments	-	-	-
	(26)	-	(26)

Total			
($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	159	18	177
Non-current fair value of financial instruments	-	-	-
	159	18	177

The fair value of the financial contracts outstanding as at March 31, 2019 is $0.2 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the year, having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the twelve months ended March 31, 2019, the derivative commodity contracts resulted in a realized loss of $1.2 million (March 31, 2018 – gain of $0.6 million) and an unrealized gain of $1.1 million (March 31, 2018 – loss of $1.7 million).

Royalties

Royalties	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Royalty expense ($000s)	59	136	570	642
$/bbl	2.33	4.53	5.24	4.88
% of revenue	2	5	5	6

In Australia, oil royalties are based on a government-established rate of 10% plus a Native Title royalty of 1%. The royalty rate is applied to gross revenues after deducting an allowance for allowable capital, transportation and operating costs. An increase in capital expenditure in fiscal 2019 has resulted in a reduced royalty expense rate of 5.08% of oil sales revenue.

Royalties per barrel in Q4 fiscal 2019 were 2% of revenue due to an adjustment made to reflect the annual fiscal royalty rate of 5.08%.

Operating Expenses

($000s) **Operating expenses**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Production	(231)	151	307	(239)
Transportation	805	926	3,318	3,957
	574	1,077	3,625	3,718
Production - $/bbl	(9.13)	5.02	2.82	(1.82)
Transportation - $/bbl	31.81	30.82	30.52	30.10
	22.68	35.84	33.34	28.28

Total operating expense during the fourth quarter fiscal 2019 was $0.6 million, 47% lower than the fourth quarter of fiscal 2018. The lower operating expense was due to the realization of a $0.4 million or $13.67/bbl credit due to Bengal as a result of an audit of our JV partner during the current quarter and charged against the production line item. For Q4 fiscal 2019, the operating expense per barrel was $22.68/bbl as compared to $35.84/bbl for Q4 fiscal 2018. Full year fiscal 2019 operating expense was $3.6 million or $33.34/bbl. The impact of the credit on full year fiscal 2019 was $3.18/bbl. This compares to the operating expense for fiscal 2018 of $3.7 million or $28.28/bbl. The lower cost per barrel in fiscal 2018 is due to higher production than in fiscal 2019 even after the JV credits are taken into account.

General and Administrative (G&A) Expenses

($000s) **G&A**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Total G&A	842	834	3,286	3,193
Capitalized Staff G&A	(36)	(69)	(190)	(295)
Capitalized Contractors G&A	-	(151)	(196)	(500)
Net G&A	806	614	2,900	2,398

Net G&A expenses in the fourth quarter fiscal 2019 were $0.8 million as compared to $0.6 million for the fourth quarter fiscal 2018. The full year fiscal 2019 saw net G&A expense at $2.9 million compared to $2.4 million for the full year fiscal 2018. The 21% increase or $500K in net G&A expense for the full year fiscal 2019 is due to a lower amount of activity by staff and contractors that was charged to capital projects

Share-based Compensation ("SBC")

($000s) **SBC**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Expensed share-based compensation	13	28	69	95
Capitalized share-based compensation	1	5	8	15
	14	33	77	110

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; they vest one-third on the first anniversary of the grant date and one-third on each of the following two annual anniversaries.

Depletion and Depreciation (DD&A)

($000s) DD&A	Three months ended March 31 2019	2018	Twelve months ended March 31 2019	2018
Petroleum and natural gas properties	370	573	1,446	2,026
Other assets	3	3	11	14
	373	576	1,457	2,040
Petroleum and natural gas properties - $/bbl	14.62	19.07	13.30	15.41

The Company's 2P reserve volumes at March 31, 2019, decreased 326,000 bbls compared to March 31, 2018. In addition, capital costs to develop proven and probable reserves at March 31, 2019, was $62.4 million compared to $58.1 million at March 31, 2018.

Production in Q4 fiscal 2019 was 25,303 bbls compared with 30,050 bbls in Q4 fiscal 2018. These amounts resulted in a depletion rate of 0.41% for Q4 fiscal 2019, compared to 0.47% for the comparative period. This lower depletion rate more than compensated for the increased capital costs to develop proven and probable reserves.

Production for the fiscal year 2019 was 108,731 bbls compared to 131,455 bbls for the previous year, resulting in a lower depletion rate for fiscal 2019. This lower depletion rate again more than compensated for the increased capital costs to develop proven and probable reserves at March 31, 2019.

Impairment

($000s) Impairment expense	Three months ended March 31 2019	2018	Twelve months ended March 31 2019	2018
Exploration and evaluation assets	-	12,167	885	12,167
Petroleum and natural gas properties	1,906	-	1,906	-
	1,906	12,167	2,791	12,167

During Q4 fiscal 2019, the Company took an impairment charge of $1.9 million due to two development wells, Cuisinier-26 and Cuisinier-30, deemed to be uneconomic following the five well drilling program and additional appraisal well, C-19, also deemed to be uneconomic. In Q2 fiscal 2019, the Company impaired an exploration well drilled and deemed uneconomic. At March 31, 2018, the Company took a $12.2 million impairment to its Exploration and Evaluation assets primarily related to ATP 732.

Finance Expense

($000s) Finance expense	Three months ended March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Interest income	(1)	(1)	(10)	(13)
Accretion expense on decommissioning and restoration liability	9	9	39	37
Letter of credit charges	-	-	8	-
Interest on Credit Facility	294	236	1,034	954
	302	244	1,071	978

Interest on the Credit Facility had been based on US dollar LIBOR + 3.2% margin. The revised Credit Facility amendment dated November 2018 increased the margin to 3.75% effective January 1, 2019.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Geological and geophysical	99	1,586	309	2,139
Drilling	1,530	-	2,360	(52)
Completions	844	(1,156)	1,677	915
Acquisition	-	509	-	509
	2,473	939	4,346	3,511
Exploration and evaluation expenditures	60	1,996	930	2,277
Development and production expenditures	2,413	(1,057)	3,416	1,234
	2,473	939	4,346	3,511

The development and production expenditure of $2.4 million in Q4 fiscal 2019 relates to the commencement of the five well drilling program and waterflood pilot that will continue through Q3 fiscal 2020. The credit of $1.1 million in Q4 fiscal 2018 was a result of a transfer of costs from PP&E to E&E.

CREDIT FACILITY

In October 2014, Bengal closed its US$25.0 million secured credit facility (the "Credit Facility") with Westpac Institutional Bank ("Westpac") and placed an initial draw on November 12, 2014 of US$14.0 million. On August 25, 2016, following a US$1.5 million repayment, the Company extended the Credit Facility by 18 months to December 2018 with a borrowing base of US$15.0 million. On September 25, 2017, the Company extended the Credit Facility to December 2019 with a borrowing base of US$12.5 million. On March 5, 2018, the Credit Facility was further amended to delay the majority of principal payments into 2019. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US LIBOR plus 3.2%.

The Credit Facility is structured as a reserve-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. Under the amendment to the Credit Facility dated March 5, 2018, the Company was required to make a US$1.5 million principal payment on December 31, 2018 and a further US$5.0 million on June 30, 2019 and US$6.0 million on December 30, 2019. In addition, the Company had agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement that requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve-based review by April 30, 2019. Pursuant to these terms, the Company repaid US$131,000 during Q3 fiscal 2019.

On November 19, 2018, the Company and Westpac entered into a revised amendment agreement to the Credit Facility to defer all principal payments previously required under the March 5, 2018 amendment to February 15, 2020. This revised amendment now requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. All other terms and conditions previously provided under the March 5, 2018 amendment remain in effect. There was an interest rate change from LIBOR plus 3.2% to 3.75% effective January 1, 2019. Given the repayment date of February 15, 2020, the debt has been classified as current at March 31, 2019.

On May 29, 2019, the Company and Westpac entered into an amendment to the November 19, 2018 agreement that has all principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment have transferred directly to the May 29, 2019 amendment.

The Credit Facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the Credit Facility. The Company was in compliance with the stated covenants at March 31, 2019.

SHARE CAPITAL

Trading history	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
High ($)	0.14	0.13	0.18	0.17
Low ($)	0.10	0.09	0.09	0.08
Close ($)	0.12	0.10	0.12	0.10
Volume (000s)	2,178	2,801	9,778	15,454
Shares outstanding (000s)	102,267	102,267	102,267	102,267
Weighted average shares outstanding (000s) - basic and diluted	102,267	102,267	102,267	102,267

At June 20, 2019, there were 102,266,694 common shares issued and outstanding, together with 4,102,500 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, fair value of financial instruments and Credit Facility, amounting to $19.1 million at March 31, 2019 (March 31, 2018 - $19.3 million).

At March 31, 2019, the Company had a working capital deficiency of $12.7 million, including cash and short-term deposits of $2.9 million and restricted cash of $0.1 million, compared to working capital of $3.4 million at March 31, 2018 and working capital of $6.3 million at December 31, 2018. The working capital deficit of $12.7 million is primarily a result of the reclassification of the bank debt of $16.5 million to current from long term.

Notwithstanding the bank debt reclassification, the working capital at March 31, 2019 would have been a positive $3.7 million. The Company does not anticipate any difficulty in meeting its current obligations as the Company has generated positive working capital and is forecasted to continue to generate positive working capital. The Company has no available undrawn debt capacity under its Westpac Credit Facility

The Company has significant spending commitments to be incurred by February 2021 on ATP 934 and has its US$12.4 million Credit Facility that matures in April 2020. Management anticipates that future and ongoing discussions with Westpac will defer the current repayment date and that operating and capital requirements will be met out of operating cash flows in addition to alternative forms of capital raising. There can be no guarantees that alternative forms of capital raising will be available or obtained on terms that are satisfactory to the Company. Should the Bank not further defer principal payments and the Company be unsuccessful in obtaining additional funding, there will be an adverse impact to the Company's liquidity.

The majority of the Company's oil sales are benchmarked on Brent prices, which averaged US$70.15/bbl for the twelve months, ended March 31, 2019. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of lower crude prices, the Company is acting with its Joint Venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where practical and appropriate. The Company intends to use a combination of internally generated sources of cash and externally generated sources of cash, such as farm-outs and alternative financing sources to fund its exploration and development activities through fiscal 2019 and beyond.

The table below indicates the payment schedule for the Company's Credit Facility:

(US$000s)	
Credit Facility	
Fiscal year 2020	12,369

Management is in discussion with the lender to further amend the current repayment terms. There would be an adverse impact on the Company's liquidity should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility.

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 FY 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 AUS$0.2 million on certification by an independent competent person appointed by the buyer of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of first commercial gas to market. The work program consists of 260 km^2 of 3D seismic and three wells.

AFE commitments are reflected where the Company has agreed with Joint Venture partners to proceed with activities (e.g. onshore Australia, Barta Block Cuisinier PL 303). The costs of these activities are based on minimum work budgets included in bid documents and agreements among Joint Venture parties, and have not been provided for in the financial statements. Actual costs may vary from budget. See Liquidity Risk and Capital Resources above.

At March 31, 2019, 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 three wells with fracs and casing	February 2021	13.4
Onshore Australia – ATP 732	Geological and geophysical studies	March 2021	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2019 at an exchange rate of AUS$1.00 = CAD$ 0.9473.

At March 31, 2019, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	737	155	311	271	-

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2018	Mar 31 2018 Q4 2018	Dec 31 2017 Q3 2018	Sep 30 2017 Q2 2018	Jun 30 2017 Q1 2017
Oil sales	2,667	2,014	3,315	3,215	2,783	3,211	2,410	2,306
Cash from operations	635	434	603	1,019	858	431	648	1,690
Funds from (used in) operations[1]	842	(247)	750	875	525	1,268	110	1,834
per share – basic and diluted ($)	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.02
Net (loss) income	(2,144)	883	(728)	(486)	(12,526)	206	(500)	54
per share – basic and diluted ($)	(0.02)	0.01	(0.01)	0.00	(0.12)	0.00	0.00	0.01
Capital expenditures	2,473	298	1,274	301	939	342	1,527	703
Working capital (deficiency)	(12,740)	6,331	(3,353)	(2,915)	3,385	(637)	2,107	(2,477)
Total assets	42,489	44,291	43,547	44,867	45,714	56,932	56,032	57,104
Shares outstanding (000s)	102,667	102,667	102,667	102,667	102,667	102,667	102,667	102,667
Operations:								
Oil volumes (bbls)	281	300	292	318	334	354	383	369
Netback[1] ($/bbl)	76.82	22.54	59.58	55.69	42.66	63.13	27.21	78.02

(1) See “Non-IFRS Measurements” on page 19 of this MD&A.

Production over the last eight quarters peaked during the second quarter of fiscal 2018 (calendar Q3 2017) as all wells from the Company's 2014 and 2016 drilling campaign were on stream. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since the peak in the second quarter of fiscal 2018. Significant declines in $US Brent during Q3 fiscal 2019 resulted in the lowest sales revenue in the past eight quarters. The Company began a five well drilling program in Q4 fiscal 2019 that will be completed by the end of Q1 fiscal 2020. The current quarter also saw a significant rebound in $US Brent pricing that saw a return to strong sales revenue and cash from operations.

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, 2019 due to the material weaknesses noted below.

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

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

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

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

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

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. 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.

(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

Bengal's assets are aggregated into cash-generating units, for the purpose of calculating impairment, 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

Judgments are required to assess when impairment indicators exist and impairment testing is required. 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.

Recognition of deferred income tax assets

The recognition of deferred income tax assets requires judgments regarding the likelihood and applicability of future income tax deductions. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and ability to apply income tax deductions.

(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

For the purposes of determining whether impairment of petroleum and natural gas assets occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of assets, and impairment charges and reversal will affect profit or loss.

Reserves

The estimate of petroleum and natural 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 development and production assets 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. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing 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.

NEW ACCOUNTING STANDARDS

On April 1, 2018, Bengal retrospectively adopted IFRS 15 Revenue from Contracts with Customers ("IFRS 15"). There were no adjustments made to the April 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are detailed in Note 13 to the March 31, 2019 consolidated financial statements.

On April 1, 2018, Bengal retrospectively adopted IFRS 9 Financial Instruments ("IFRS 9"), which includes new requirements for the classification and measurement of financial assets, a new credit loss impairment model and a new model to be used for hedge accounting for risk management contracts. The Company currently has risk management contracts but does not use hedge accounting. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition. The additional disclosures required by IFRS 9 are detailed in Note 4 to the March 31, 2019 consolidated financial statements.

FUTURE ACCOUNTING STANDARDS

IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"). This standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than 12 months. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on April 1, 2019. The Company's assessment of the impact of the adoption of the standard is still in progress.

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

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

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

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

($000s)	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Cash from operating activities	635	858	2,691	3,627
Changes in non-cash working capital	207	(333)	(471)	110
Funds from operations	842	525	2,220	3,737

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**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Net loss	(2,144)	(12,526)	(2,475)	(12,271)
Unrealized loss (gain) on financial instruments	740	(39)	(1,086)	1,661
Unrealized foreign exchange (gain) loss	(105)	255	1,295	(98)
Non-cash impairment of non-current assets	1,906	12,167	2,791	12,167
Adjusted net income (loss)	397	(143)	525	1,459

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.

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. 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, will 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 will 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 will affect Bengal’s ability to expend the necessary capital to replace its reserves or to maintain its production. If Bengal’s funds from 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 2000, 715 5th Avenue SW., Calgary, Alberta T2P 2X6, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

Forward-looking Statements - *Certain statements contained within this MD&A constitute forward-looking statements or information ("forward-looking statements") as defined by applicable securities laws. These statements relate to future events or Bengal's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. The projections, estimates and beliefs contained in such forward-looking statements are based on management's estimates, opinions, and assumptions at the time the statements were made, including assumptions relating to: the impact of economic conditions in North America and Australia and globally; industry conditions; changes in laws and regulations including, without limitation, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the availability of qualified operating or management personnel; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and fluctuations in market valuations of companies with respect to announced transactions and the final valuations thereof; results of exploration and testing activities; and the ability to obtain required approvals and extensions from regulatory authorities.*
In particular, this MD&A contains forward-looking statements pertaining to the following:

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Bengal's drilling program and waterflood pilot;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *The expectation that the Joint Venture's drilling campaign will allow for fracture stimulations to occur upon completion as required and result in operational efficiencies, cost savings and improved initial production rates;*

- *The timing of first oil sales from the new 2019 wells;*
- *The expected operational efficiencies and cost savings as well as potentially improved initial production rates in relation to the fracture stimulation campaign on four wells on ATP 752;*
- *The potential of further development drilling opportunities and pool expansion upside in the DC-50 sand in the Cuisinier 29 well;*
- *The timing of further results on the 2019 drilling program completion;*
- *The expected timing of the commencement of a pilot pressure maintenance scheme and the potential positive performance response of up to four offsetting producing wells in the Cuisinier field;*
- *The timing of the completion of the depth image processing completion on ATP 934;*
- *The possibility of third parties farming in 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; and*
- *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.*

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;*
- *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, 2019 (the "GLJ Report"). The GLJ Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and the reserve definitions contained in National Instrument 51-101 – Standards of Disclosure For Oil and Gas Activities ("NI 51-101").

This document includes estimates of thickness net pay, which estimates may be considered to be anticipated results under NI 51-101. The estimates were prepared internally. References to thickness of "net oil pay" or of a formation where evidence of hydrocarbons has been encountered is not necessarily an indicator that hydrocarbons will be recoverable in commercial quantities or in any estimated volume. Bengal may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves. Well test results should be considered as preliminary and not necessarily indicative of long-term performance or of ultimate recovery. Well log interpretations indicating oil and gas accumulations are not necessarily indicative of future production or ultimate recovery. If it is indicated that a pressure transient analysis or well-test interpretation has not been carried out, any data disclosed in that respect should be considered preliminary until such analysis has been completed.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Matthew Moorman, Chief Financial Officer
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG