



International exploration & production

Management's Discussion & Analysis

**Three and Nine Months Ended
December 31, 2016 and 2015**

THIRD QUARTER FISCAL 2017 HIGHLIGHTS

Financial Highlights:

- **Sales Revenue** – Crude oil sales before hedging gains were \$2.3 million in the third quarter of fiscal 2017, which is 26% higher than the \$1.8 million recorded in the third quarter of fiscal 2016 and consistent with the preceding quarter.
- **Hedging in place through June 2017** – the Company has approximately 58,000 barrels of production hedged with a floor price of US \$80 per barrel through to June 2017. From July 2017 through to December 2018, the Company has hedged approximately 133,000 barrels of production at a floor price of US \$47 per barrel. During the quarter ended December 31, 2016, realized gains on derivative financial instruments were \$1.1 million.
- **Funds Flow from Operations⁽¹⁾** – Bengal generated funds flow from operations of \$1.4 million in the quarter ended December 31, 2016 a 22% decrease from the \$1.8 million generated in the preceding quarter and a 1234% increase compared to the third quarter of fiscal 2016.
- **Net Income** – Bengal reported a net loss of \$2.3 million for the quarter compared to net income of \$0.3 million in the preceding quarter, and net income of \$1.4 million in the third quarter of fiscal 2016. Adjusted net earnings¹ were \$0.8 million for the third quarter of fiscal 2017 compared to an adjusted net loss of \$1.1 million in the third quarter of fiscal 2016 and the preceding quarter. Adjusted net earnings excludes the impact of unrealized foreign exchange and unrealized hedging gains and losses.
- **Rights Offering** – On December 29, 2016, Bengal completed a rights offering raising \$4.0 million net of \$0.1 million share issue costs.

Operational Highlights:

- **Cuisinier 2016 completion program** – Following up on its successful five well drilling program at Cuisinier, the Barta joint venture planned for the completion of four wells in conjunction with a two well fracture stimulation program. Commencing in late December, the fracture stimulation program includes Barta North 1 and Cuisinier 22, which was part of the 2016 drilling program. Completions and tie in activities are expected to occur before the quarter ending June 30, 2017.
- **Production Volumes** – Production in the third quarter of fiscal 2017 averaged 355 barrels of oil equivalent per day (“boepd”), an 8% and 19% decrease from the previous quarter and fiscal Q3 2016 respectively.

MANAGEMENT’S DISCUSSION AND ANALYSIS – February 8, 2017

Bengal’s producing assets are situated in Australia’s Cooper Basin, a region featuring large hydrocarbon pools. The Company’s core Australian assets, Cuisinier and Tookoonooka, are situated within an area of the Cooper Basin. Still in early stages, in terms of appraisal and development, Bengal believes these assets offer attractive upside potential. Australia features a stable political, fiscal and economic environment in which to operate, with a favourable royalty regime for oil and gas production.

¹ See non-IFRS measurements section on page 5 of this MD&A

OUTLOOK

AUSTRALIA

ATP 752 Barta Block Cuisinier

During fiscal Q4 2017, the Company expects to complete and tie in four wells (Cuisinier 22, Cuisinier 24, Cuisinier 25 and Shefu1) following its fracture stimulation program of Barta North 1 and Cuisinier 22. During the second half of calendar 2017 the Joint Venture will commence a fracture stimulation program on Cuisinier North 1, Cuisinier 2 and Cuisinier 19. Production testing at these new and stimulated wells will assist the joint venture in planning for its next drilling campaign. The Cuisinier 23 well has encountered hydrocarbon bearing sands based on logging results, however estimated deliverability is uncertain, therefore future completion and potential stimulation of this well will be evaluated following the ongoing completion campaign.

The near field exploration well Shefu-1 confirms a westerly extension of the Cuisinier pool within PL303 and oil pay was found to occur structurally lower than what has been encountered in previous rounds of appraisal drilling at Cuisinier, therefore lowering the "lowest known oil" for the area. Bengal's internal estimates suggest that this Shefu-1 result has the potential to materially increase the Cuisinier area oil in place and reserves, given that the Murta reservoir in the Shefu-1 area is well outside of Bengal's currently booked 1P, 2P and 3P reserves areas.

The joint venture is also in the preliminary stages of planning for a 3D seismic program in the Barta West area, immediately west of Cuisinier PL303. The exact size and timing will be finalized in the coming months.

ATP 934 Barrolka

Bengal has completed reprocessing of 500+ line kilometers of 2D seismic over the permit and interpretation of this data is now complete. The most favorable areas have been high-graded for additional detailed geophysical work that may include the acquisition of 3D seismic in 2017. The Company is encouraged by recent natural gas discoveries near the Barrolka permit, which suggest the presence of a basin centered gas play in the region, as well as significant conventional potential for natural gas occurrence in the Permian Toolachee and Patchawarra sandstone reservoirs. Bengal is operator with a 71% working interest in this permit and has held preliminary discussions with third parties who may have an interest in farming in on this block

ATP 732 Tookoonooka Block

The Tookoonooka Permit (ATP 732 – 100% WI effective January 28, 2016) is located in the emerging East Flank oil fairway of the Cooper Basin. Beach Energy Ltd. ("Beach") completed the acquisition of 300 sq. km 3D seismic in Tookoonooka in February 2014 and subsequently relinquished its interest in the permit; Bengal was fully carried for the cost of this seismic program. While there are no outstanding commitments on this permit, Bengal is currently studying the Permian gas potential along the northern flank of the permit as well as the largely unexplored oil potential in the southern part of the permit closer to the producing Jackson/Jackson South Field which has produced 49.4 million barrels of oil to date.

ATP 752 Wompi

The Nubba-1 well encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas. Pressure testing, as well as logging, suggests that this Toolachee gas well could be part of a gas column that may be up to 70 metres in height. This suggests the prospective gas pay extends down

dip of the Nubba well where seismic indicates the Toolachee section thickens. A Potential Commercial Area (PCA) will be applied for which will allow for commercialization. The produced natural gas would likely be pipeline connected to the nearest gas transmission line in the area, which is approximately 5 kilometres from the Nubba-1 well. Wompi (38% Bengal interest) offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential and the joint venture is currently evaluating the appropriate timing to continue the development of this discovery, which is not expected to occur during the first half of calendar 2017.

Business Development

The Company, encouraged by increased deal flow in Australia's Cooper Basin, continues to examine potential transactions targeting complementary asset bases to increase reserves, production and cash flows per share.

OPERATING HIGHLIGHTS

\$000s except per share, volumes and netback amounts	Three Months Ended			Nine Months Ended		
	December 31			December 31		
	2016	2015	% Change	2016	2015	% Change
Oil sales revenue	\$ 2,325	\$ 1,838	26	\$ 7,115	\$ 8,934	(20)
Realized gain on financial instruments	\$ 1,149	\$ 838	37	\$ 3,741	\$ 2,007	86
Royalties	\$ (47)	\$ 133	(135)	\$ 134	\$ 622	(78)
% of revenue	(2)	7	(129)	2	7	(71)
Operating & transportation	\$ 1,270	\$ 1,432	(11)	\$ 3,877	\$ 5,006	(23)
Operating netback ⁽¹⁾	\$ 2,251	\$ 1,111	103	\$ 6,845	\$ 5,313	29
Cash from operations	\$ 934	\$ 935	5	\$ 3,872	\$ 3,902	-
Funds from operations: ⁽²⁾	\$ 1,412	\$ 105	1,245	\$ 4,557	\$ 2,609	75
Per share (\$) (basic & diluted)	0.02	0.01	-	0.07	0.04	75
Net income (loss)	\$ (2,288)	\$ 1,413	(262)	\$ (4,699)	\$ 1,324	(455)
Per share (\$) (basic & diluted)	(0.03)	0.02	(250)	(0.07)	0.02	(450)
Adjusted net income (loss) ⁽³⁾	\$ 773	\$(1,123)	(169)	\$ 2,424	\$(1,585)	(253)
Per share (\$) (basic & diluted)	0.01	(0.02)	(150)	0.04	(0.02)	(300)
Capital expenditures	\$ 1,234	\$ 1,311	(6)	\$ 4,937	\$ 3,015	64
Oil Volumes (bopd)	355	439	(19)	391	517	(24)
Netback ⁽¹⁾ (\$/boe)						
Revenue	\$ 71.28	\$ 45.56	56	\$ 66.24	\$ 62.85	5
Realized gain on financial instruments	35.22	20.77	70	34.83	14.12	147
Royalties	(1.44)	3.30	(144)	1.25	4.38	(71)
Operating & transportation	38.93	35.49	10	36.10	35.22	3
Netback/boe	\$ 69.01	\$ 27.54	151	\$ 63.72	\$ 37.37	71

(1) Operating netback is a non-IFRS measure and includes realized gain on financial instruments. Netback per boe is calculated by dividing revenue (including realized gain on financial instruments) less royalties, operating and transportation costs by the total production of the Company measured in boe.

(2) Funds from operations is a non-IFRS measure. The comparable IFRS measure is cash from operations. A reconciliation of the two measures can be found in the table on page 5.

(3) Adjusted net (loss) is a non-IFRS measure. The comparable IFRS measure is net income (loss). A reconciliation of the two measures can be found in the table on page 5.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the three and nine months ended December 31, 2016 and 2015. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from October 1, 2016 through December 31, 2016. The terms "prior year's quarter" and "2016 quarter" are used throughout the MD&A for comparative purposes and refer

to the period from October 1, 2015 through December 31, 2015. The terms “prior quarter”, “preceding quarter” and “previous quarter” refer to the three months ended September 30, 2016.

The fiscal year for the Company is the twelve-month period ended March 31, 2017. The terms “fiscal 2017,” “current year” and “the year” are used in the MD&A and in all cases refer to the period from April 1, 2016 through March 31, 2017. The terms “previous year,” “prior year” and “fiscal 2016” are used in the MD&A for comparative purposes and refer to the period from April 1, 2015 through March 31, 2016. The term YTD means year-to-date.

The following abbreviations are used in this MD&A: boepd means barrels of oil equivalent per day; bpd means barrels per day; mcfpd means thousand cubic feet of natural gas per day; \$/boe means Canadian dollars per boe; and NGL means natural gas liquids.

Non-IFRS Measurements

Within the MD&A references are made to terms commonly used in the oil and gas industry. Funds from operations, funds from operations per share and netbacks do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Funds from operations represents cash from operating activities as presented in the consolidated statement of cash flows adding back changes in non-cash working capital and the settlement of decommissioning liabilities. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income (loss) per share. Netbacks equal total revenue (including realized gain on financial instruments) less royalties and operating and transportation expenses calculated on a boe basis. Management utilizes these measures to analyze operating performance. Funds from operations is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net income, cash from operations or other measures of financial performance calculated in accordance with IFRS. Funds from operations, commonly referred to as cash flow by research analysts, is used to value and compare oil and gas companies and is frequently included in published research when providing investment recommendations.

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

	Three Months Ended December 31			Nine Months Ended December 31		
	2016	2015	% Change	2016	2015	% Change
\$000s						
Cash flow from (used in) operating activities	934	935	(5)	3,872	3,902	-
Changes in non-cash working capital	478	(830)	(152)	685	(1,293)	(149)
Funds from operations	1,412	105	1,245	4,557	2,609	75

Adjusted net earnings 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 earnings equal net income (loss) less unrealized losses/gains on foreign exchange and unrealized losses/gains on financial instruments. Adjusted net earnings per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

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

\$000s	Three Months Ended December 31			Nine Months Ended December 31		
	2016	2015	% Change	2016	2015	% Change
Net income (loss)	(2,288)	1,413	(262)	(4,699)	1,324	(455)
Unrealized loss (gain) on financial Instruments	2,090	(1,663)	(226)	6,067	(3,802)	(260)
Unrealized foreign exchange (gain) loss	971	(873)	(211)	1,056	893	18
Adjusted net earnings (loss)	773	(1,123)	(169)	2,424	(1,585)	(253)

RESULTS OF OPERATIONS - AUSTRALIA

Netbacks

Production	Three Months Ended December 31			Nine Months Ended December 31		
	2016	2015	% Change	2016	2015	% Change
Oil Production (bpd)	355	439	(19)	391	517	(24)
(\$000s)						
Oil sales	2,325	1,838	26	7,115	8,934	(20)
Realized gain on financial instruments	1,149	838	37	3,741	2,007	86
Royalties	(47)	133	(135)	134	622	(78)
Operating and transportation expenses	1,270	1,429	(11)	3,877	4,994	(22)
Netback (\$000s)	2,251	1,114	102	6,845	5,325	29
Oil sales (\$/bbl)	71.28	45.56	56	66.24	62.85	5
Realized gain on financial instruments (\$/bbl)	35.22	20.77	70	34.83	14.12	147
Royalties (\$/bbl)	(1.44)	3.30	(144)	1.25	4.38	(71)
Operating and transportation expenses	38.93	35.42	10	36.10	35.13	3
Netback (\$/bbl)	69.01	27.61	150	63.72	37.46	70

Production, Commodity Pricing and Sales

Production

Crude oil production decreased 8% and 19% compared to the prior quarter and fiscal Q3 2016 respectively. This decrease is due to natural declines at the Cuisinier field as well as the impact of several planned shut-ins of the Barta North 1 and Cuisinier 22 wells in preparation for fracture stimulation. The impact of these planned outages was approximately 30 bopd net to Bengal.

Pricing

The price received for Bengal's Australian oil sales is benchmarked on Dated Brent quotes as published by Platts Crude Oil Marketwire for the month in which the Bill of Lading occurs, plus a Platts Tapis premium. Brent typically has traded at a premium to West Texas Intermediate (WTI) and the Platts Tapis premium received has averaged US \$1.61/bbl over Brent for the nine months ended December 31, 2016 (2015 – US \$2.03).

Realized crude oil prices (before realized gain on financial instruments) increased 10% and 56% compared to the prior quarter and fiscal Q3 2016 respectively. Increases from the prior quarter were due to corresponding increased benchmark pricing. Realized prices increased disproportionately relative to underlying commodity prices compared to fiscal Q3 2016 due to the impact of approximately 21,000 barrels of oil sales that were shipped but not priced during fiscal Q3 2017. These barrels were priced at a value of

US \$55.46 per barrel based on January pricing, which is 12% higher than average benchmark pricing for fiscal Q3 2017.

The following table outlines average benchmark prices compared to Bengal's realized prices:

Prices and Marketing	Three Months Ended December 31			Nine Months Ended December 31		
	Average Benchmark Price	2016	2015	% Change	2016	2015
Bengal crude oil sales price before realized gain on financial instruments(\$CAD/bbl)	\$ 71.28	\$ 45.56	56	\$ 66.24	\$ 62.85	5
Realized gain on financial Instruments (\$CAD/bbl)	35.22	20.77	70	34.83	26.75	30
Dated Brent oil (\$CAD/bbl)	66.02	58.33	13	61.48	67.06	(8)
Dated Brent oil (\$US/bbl)	49.46	43.69	13	46.96	51.96	(10)
Number of CAD\$ for 1 AUS\$	1.00	0.96	4	0.98	0.96	2
Number of CAD\$ for 1 US\$	1.33	1.34	(1)	1.31	1.29	2

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.

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 loss.

The company has the following derivative contracts:

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US\$/bbl)	Price Ceiling (US\$/bbl)
January 1, 2017 – May 31, 2017	Oil - Swap	31,728	80.00	80.00
January 1, 2017 – May 31, 2017	Oil – Put option	25,957	80.00	-

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US\$/bbl)	Price Ceiling (US\$/bbl)
July 1, 2017 – December 31, 2018	Oil - Swap	67,373	47.00	47.00
July 1, 2017 – December 31, 2018	Oil – Put option	67,373	47.00	-

The fair value of the financial contracts outstanding as at December 31, 2016 is an estimated asset of \$0.9 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 period 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 three months ended December 31, 2016, the derivative commodity contracts resulted in a realized gain of \$1.1 million (fiscal Q3 2015 - \$0.8 million gain) and an unrealized loss of \$2.1 million (fiscal Q3 2016 - \$1.7 million gain). During fiscal Q3 2017 the Company contracted approximately 30,000 bbls compared to 18,000 barrels during fiscal Q3 2016, therefore realized hedging gains were 37% higher despite an increase in the underlying commodity prices. The Company recognized unrealized losses due to increased Brent forward strip pricing at December 31, 2016 compared to March 31, 2016 as well as the implementation of new derivative contracts with a lower floor price.

Royalties

Royalties (\$000s)	Three Months Ended			Nine Months Ended		
	December 31			December 31		
	2016	2015	% Change	2016	2015	% Change
Royalty Expense	(47)	133	(135)	134	622	(78)
\$/bbl	(1.44)	3.30	(144)	1.25	4.38	(71)
% of revenue	(2)	7	(128)	2	7	(71)

In Australia, oil royalties are based on a government-established rate of 10% plus a Native Title royalty which is typically 1%. The royalty rate is applied to gross revenues after deducting an allowance for allowable capital, transportation and operating costs, resulting in an effective rate of less than 10%.

Royalties per barrel have decreased 144% compared to Q3 2016 and decreased 238% compared to the previous quarter. The Company recorded a royalty credit during fiscal Q3 2017 following the filing of the annual Cuisinier royalty return in December 2016. The Operator has applied for inclusion of additional capital costs, which have significantly lowered the annual Cuisinier royalty burden resulting in a credit during the quarter.

Operating & Transportation Expenses

Operating & trans. expenses (\$000s)	Three Months Ended			Nine Months Ended		
	December 31			December 31		
	2016	2015	% Change	2016	2015	% Change
Operating	217	211	3	510	835	(39)
Transportation	1,053	1,218	(14)	3,367	4,159	(19)
	1,270	1,429	(11)	3,877	4,994	(22)
Operating - \$/boe	6.65	5.23	27	4.75	5.87	(19)
Transp. - \$/boe	32.28	30.19	7	31.35	29.26	7
	38.93	35.42	10	36.10	35.13	3

Operating costs per barrel increased by 27% compared to Q3 2016 and increased by 123% compared to the prior quarter. The Cuisinier field experienced several non-recurring operating charges for equipment replacement and well treatments resulting in increased operating expenses per barrel compared to the prior year and quarter.

Transportation costs on a boe basis have increased 7% compared to Q3 2016 and increased 6% compared to the prior quarter. Transportation costs include processing and handling fees which have increased over the past year due to increased water production at the Cuisinier field. During fiscal Q3 2017 the Cook to Merrimelia pipeline was offline for service over a three week period which resulted in increased transportation charges associated with alternate transport routes.

General and Administrative (G&A) Expenses and Share-based Compensation ("SBC")

G&A Expenses and SBC (\$000s)	Three Months Ended			Nine Months Ended		
	December 31			December 31		
	2016	2015	% Change	2016	2015	% Change
Net G&A	650	649	-	2,019	1,973	2
Capitalized G&A	83	83	-	255	244	5
Total G&A	733	732	-	2,274	2,217	3
Expensed share-based compensation	-	26	(100)	25	74	(66)
Capitalized share-based compensation	-	3	(100)	6	10	(40)
Total share-based compensation	-	29	(100)	31	84	(63)

G&A expenses have remained consistent with the prior year and prior quarter as a result of the Company's ongoing efforts to reduce discretionary spending and general charges.

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 three to five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries. Options granted in July of 2015 vest conditionally based on certain performance criteria on their first, second and third anniversaries. The decrease in share-based compensation expense reflects the absence of any option grants during the quarter ended December 30, 2016.

Depletion and Depreciation (DD&A)

DD&A Expenses (\$000s)	Three Months Ended December 31			Nine Months Ended December 31		
	2016	2015	% Change	2016	2015	% Change
PNG – Australia	562	1,078	(48)	1,847	3,753	(51)
Corporate	5	6	(17)	15	19	(21)
Total	567	1,084	(48)	1,862	3,772	(51)
\$/boe – PNG Australia	17.23	26.72	(36)	17.20	26.40	(35)

Decreased depletion per barrel resulted from a 9% increase in the Company's 2P reserve values compared to the prior year as well as a material decrease in the expected future costs associated with developing these reserves.

Finance Income/Expenses

Finance Income/Expenses (\$000s)	Three Months Ended December 31			Nine Months Ended December 31		
	2016	2015	% Change	2016	2015	% Change
Interest income	1	2	(50)	4	7	(43)
Accretion expense on decommissioning liabilities	(10)	(8)	25	(27)	(24)	13
Change in FV of VARs	-	3	(100)	-	2	(100)
Letter of credit charges	-	-	-	(55)	14	(493)
Interest on credit facility	(256)	(333)	(23)	(769)	(963)	(20)
Total	(265)	(336)	(21)	(847)	(964)	(12)

Interest on the credit facility is based on US dollar Libor + 3.2% margin.

CAPITAL EXPENDITURES

Capital Expenditures (\$000s)	Three Months Ended December 31			Nine Months Ended December 31		
	2016	2015	% Change	2016	2015	% Change
Geological and geophysical	197	418	(53)	653	1,209	(46)
Drilling	58	21	176	3,027	(34)	(9,003)
Completions	979	873	12	1,257	1,730	(27)
Cuisinier working interest purchase	-	(1)	(100)	-	110	(100)
Total expenditures	1,234	1,311	(6)	4,937	3,015	64
Exploration & evaluation expenditures	69	174		310	666	(54)
Development & production expenditures	1,165	1,137		4,627	2,349	97
Total net expenditures	1,234	1,311		4,937	3,015	64

Development expenditures during the quarter related primarily to the Cuisinier 2016 drilling program.

CREDIT FACILITY

In October 2014, Bengal closed its US \$25.0 million secured credit facility with Westpac Institutional Bank and placed an initial draw on November 12, 2014 of US \$14.0 million. On August 26, 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 million. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a three-year term and carries an interest rate of US Libor plus 3.2%.

The credit facility is structured as a reserves-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. In the event that the facility is not further extended, the reduction schedule would commence on December 31, 2017 and occur every six months thereafter until December 31, 2018 with a nominal reduction of \$5 million to the facility limit at each calculation date based on the Company's existing reserve profile. The facility limit at December 31, 2016 is US \$15 million, of which US \$12.5 million is currently drawn.

The credit facility's 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. There are no financial covenants associated with this credit facility. The Company was in compliance with the stated covenants at December 31, 2016.

SHARE CAPITAL

At February 8 2017, there were 102,266,694 common shares issued and outstanding, together with 3,587,500 outstanding options.

Trading History	Three Months Ended			Nine Months Ended		
	December 31			December 31		
	2016	2015	% Change	2016	2015	% Change
High	\$ 0.24	\$ 0.21	14	\$ 0.24	\$ 0.32	(25)
Low	\$ 0.12	\$ 0.10	20	\$ 0.11	\$ 0.10	10
Close	\$ 0.17	\$ 0.14	21	\$ 0.17	\$ 0.14	21
Volume (000s)	4,016	7,841	(49)	9,179	13,646	(33)
Shares outstanding (000s)	102,267	68,178	50	102,267	68,178	50
Weighted average shares outstanding (000s)						
Basic & Diluted	68,919	68,178	1	68,426	68,178	-
Diluted	68,919	68,178	1	68,426	68,283	-

LIQUIDITY 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. In the current quarter, the Company raised gross proceeds of \$4.1 million pursuant to a rights offering. The Company's existing cash and cash equivalents and operating cash flows combined with the available credit described above are expected to be sufficient to meet all of its working capital requirements for at least the next twelve months.

At December 31, 2016 the Company had working capital of \$3.3 million, including cash and short-term deposits of \$4.9 million and restricted cash of \$0.1 million, compared to working capital of \$4.4 million at September 30, 2016 and working capital deficiency of \$0.4 million at March 31, 2016. The Company has an additional US \$2.5 million of available undrawn debt under its Westpac credit facility.

The majority of the Company's oil sales are benchmarked on dated Brent prices which averaged US \$46.96/bbl for the nine months ended December 31, 2016. 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. 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 appropriate. Under the current commodity price environment, the Company has no plans to use its internal source of cash to fund exploration activities. These are expected to be financed through farm-out or alternative financing sources.

The table below indicates the payment schedule for the credit facility:

Credit facility (US\$000s)	
Fiscal year 2018	2,500
Fiscal year 2019	10,000
	12,500

COMMITMENTS

The Queensland Government regulatory authority granted the Company the 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. Currently, the Company holds a 71.43% operating interest in this permit. Work program consists of 200 square kilometers of 3D seismic and up to three wells, which would require a capital spend of \$2.1 million in 2017 and a further \$2.1 million in 2018 net to Bengal.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD\$)⁽¹⁾
Onshore Australia – ATP 934P	200 km ² of 3D seismic and up to three wells	March 2021	\$16.1

(1) Translated at December 31, 2016 at an exchange rate of AUS \$1.00 = CAD \$0.9671

OTHER

At December 31, 2016, the contractual obligations for which the Company is responsible are as follows:

Contractual Obligations (\$000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	\$ 66	\$ 66	\$ -	\$ -	\$ -
Decommissioning obligations	1,686	-	237	117	1,332
Total contractual obligations	\$ 1,752	\$ 66	\$ 237	\$ 117	\$ 1,332

Subsequent to December 31, 2016, the Company committed to a new lease for office space in Canada from April 1, 2017 through November 30, 2023 as follows:

(\$000s)					
April 2017 to November 2023	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	943	13	311	311	308

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

(\$000s, except per share amounts)

	Dec. 31 2016	Sep. 30 2016	Jun. 30 2016	Mar. 31 2016	Dec.31 2015	Sep. 30 2015	Jun. 30 2015	Mar. 31 2015
Fiscal quarter	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	Q4 2015
Petroleum and natural gas sales	2,325	2,301	2,489	2,253	1,838	3,392	3,704	3,378
Cash from (used in) operations	934	1,982	956	1,496	935	2,318	649	978
Funds from (used in) operations ⁽¹⁾	1,412	1,797	1,348	1,439	105	1,282	1,222	939
Per share								
Basic and diluted	0.02	0.03	0.02	0.02	0.00	0.02	0.02	0.01
Net income (loss)	(2,288)	325	(2,736)	(11,704)	1,413	1,167	(1,256)	(1,052)
Per share								
Basic and diluted	(0.03)	0.00	(0.04)	(0.17)	0.02	0.02	(0.02)	(0.02)
Capital expenditures	1,234	3,320	383	332	1,311	596	1,108	2,410
Working capital (deficiency)	3,291	4,421	(9,171)	(420)	(1,487)	5,775	3,087	5,221
Total assets	56,020	55,552	54,108	58,903	72,353	66,583	62,926	65,679
Shares outstanding (000s)	102,267	68,178	68,178	68,178	68,178	68,178	68,178	68,178
Operations								
Average daily production								
Natural gas (mcfpd)	-	-	-	-	-	-	-	114
Oil and NGLs (bpd)	355	386	431	469	439	592	520	506
Combined (boepd)	355	386	431	469	439	592	520	525
Netback (\$/boe)	69.01	67.30	56.09	58.75	27.54	36.97	46.23	45.86

(1) See "Non-IFRS Measurements" on page 5 of this MD&A.

Production over the last eight quarters peaked during Q2 2016 as all wells from the Company's 2014/2015 drilling campaign were on stream. Natural declines were partially offset during Q4 2016 as incremental production from the 2016 fracture stimulation program came on stream, following which production has decreased at natural decline rates. Variances in net income have been impacted by unrealized gains/losses on foreign exchange and derivative contracts as well as material impairments recorded in Q4 fiscal 2016.

Capital expenditures have been driven by drilling programs at the Company's Cuisinier field, which peaked during fiscal Q2 2017 due to a five well drilling campaign commencing during the quarter. Total assets have increased through drilling activities at Cuisinier and were significantly reduced during fiscal Q4 2016 and fiscal Q1 2017 due to impairments of associated with the Tookoonooka exploration permit in Australia and CY-ONN-2005/1 exploration block in India respectively. Working capital reached a deficit of \$9.1 at Q1 2017 prior to the extension of the Company's Westpac credit facility in August 2017. During fiscal Q3 2017 \$3.4 million of the credit facility became current, but this decrease to working capital was offset by the Company's issuance of \$4 million in common shares.

Fluctuations in netbacks have been primarily driven by volatile benchmark crude prices as royalties and operating/transportation costs have remained consistent.

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 December 31, 2016 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;
- 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 do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates, which are reviewed on an ongoing basis. A full discussion of the Company's critical judgments and accounting estimates is included in its 2016 annual Management's Discussion and Analysis.

NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

Standards that are issued but not yet effective and that the Company reasonably expects to be applicable at a future date are listed below.

Revenue from contracts with customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers". It replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2018. The Company is currently assessing the impact of this standard.

Financial instruments: recognition and measurement

In July 2014, IFRS 9 "Financial Instruments" was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The Company is currently assessing the impact of this standard.

Leases

IFRS 16 "Leases" is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning after January 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

RISK FACTORS

There are a number of risk factors facing companies that participate in the oil and gas industry. A complete list of risk factors are provided in Bengal's Annual Information Form dated June 22, 2016 filed on SEDAR at www.sedar.com.

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

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 1810, 801 6th Avenue SW., Calgary, Alberta T2P 3W2, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

Forward-looking Statements - *Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward-looking statements. 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, or incorporated by reference into, this MD&A should not be unduly relied upon.*

In particular, this Management's Discussion and Analysis, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *The expected timing of the completion and tie-ins of the successful 5 well at Barta Block Cuisinier*
- *Timing of the finalization of the credit facility extension*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *The Company expects netbacks to remain above \$35/bbl under current market conditions;*
- *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 or share issues and funds will be sufficient to meet requirements; and*

With respect to the forward looking statements contained in the MD&A, Bengal has made assumptions regarding: future commodity prices; the impact of royalty regimes; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital; the continued availability of undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continued stability of political, regulatory; tax and fiscal regimes in which the Company has operations.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis:

- *Volatility in market prices for oil and natural gas;*
- *Liabilities inherent in oil and natural gas operations;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*

- *Incorrect assessment of the value of acquisitions;*
- *Unable to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Changes in income tax laws or changes to royalty and environmental regulations relating to the oil and gas industry;*
- *The risk that Bengal may not be successful in raising funds by an equity issue; 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 and the documents incorporated by reference herein 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).

These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Johnson Winter Slattery • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

INVESTOR RELATIONS

5 Quarters Investor Relations, Inc. • Calgary, 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

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

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
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG



**Condensed Consolidated Interim Financial
Statements (unaudited)**

**Three and Nine Months Ended
December 31, 2016 and 2015**

BENGAL ENERGY LTD.**CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION**

(Thousands of Canadian dollars)

(unaudited)

As at		December 31, 2016	March 31, 2016
	Notes		
ASSETS			
Current assets:			
Cash and cash equivalents		\$ 4,885	\$ 3,010
Restricted cash		140	140
Accounts receivable		2,849	3,187
Prepaid expenses and deposits		173	155
Fair value of financial instruments	9	1,417	5,806
		9,464	12,298
Non-current assets:			
Exploration and evaluation assets	3	19,400	19,626
Petroleum and natural gas properties	4	27,160	24,875
Fair value of financial instruments	9	-	1,294
		46,560	45,795
Total assets		\$ 56,024	\$ 58,093
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		\$ 2,814	\$ 2,669
Current portion of credit facility	5	3,359	10,049
		6,173	12,718
Non-current liabilities:			
Decommissioning liability	6	1,686	1,422
Credit facility	5	13,209	7,816
Fair value of financial instruments	9	502	-
		15,397	9,238
Shareholders' equity:			
Share capital	7	98,100	94,151
Contributed surplus		7,640	7,442
Warrants		-	167
Accumulated other comprehensive income		371	1,335
Deficit		(71,657)	(66,958)
		34,454	36,137
Total liabilities and shareholders' equity		\$ 56,024	\$ 58,093

Commitments (note 11)

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.**CONDENSED CONSOLIDATED INTERIM STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)**

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

		Three months ended December 31,		Nine months ended December 31,	
		2016	2015	2016	2015
	Notes				
Income					
Petroleum and natural gas revenue		\$ 2,325	\$ 1,838	\$ 7,115	\$ 8,934
Royalties		47	(133)	(134)	(622)
		2,372	1,705	6,981	8,312
Realized gain on financial instruments		1,149	838	3,741	2,007
Unrealized (loss) gain on financial instruments		(2,090)	1,663	(6,067)	3,802
		1,431	4,206	4,655	14,121
Operating expenses					
General and administrative		650	649	2,019	1,973
Operating and transportation		1,270	1,432	3,877	5,006
Depletion and depreciation	4	567	1,084	1,862	3,772
Share-based compensation		-	26	25	74
		2,487	3,191	7,783	10,825
Operating (loss) income		(1,056)	1,015	(3,128)	3,296
Other (expenses)					
Other		-	(2)	316	(2)
Finance (expenses)	8	(265)	(336)	(847)	(964)
Foreign exchange gain (loss)		(967)	736	(1,040)	(1,006)
		(1,232)	398	(1,571)	(1,972)
Net (loss) income		(2,288)	1,413	(4,699)	1,324
Exchange differences on translation of foreign operations		(1,138)	3,286	(964)	2,288
Total comprehensive (loss) income for the period		\$ (3,426)	\$ 4,699	\$ (5,663)	\$ 3,612
(Loss) earnings per share	7				
- Basic & diluted		\$ (0.03)	\$ 0.02	\$ (0.07)	\$ 0.02
Weighted average number of shares outstanding (000s)	7				
- Basic		68,919	68,178	68,426	68,178
- Diluted		68,919	68,178	68,426	68,283

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.**CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY**

(Thousands of Canadian dollars)

(unaudited)

	Shares outstanding	Share capital	Warrants	Contributed surplus	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2015	68,177,796	\$ 94,151	\$ 167	\$ 7,341	\$ (130)	\$ (56,578)	\$ 44,951
Net income for the period	-	-	-	-	-	1,324	1,324
Comprehensive income for the period	-	-	-	-	2,288	-	2,288
Share-based compensation – expensed	-	-	-	74	-	-	74
Share-based compensation – capitalized	-	-	-	10	-	-	10
Balance at December 31, 2015	68,177,796	94,151	\$ 167	\$ 7,425	\$ 2,158	\$ (55,254)	\$ 48,647
Balance at April 1, 2016	68,177,796	\$ 94,151	\$ 167	\$ 7,442	\$ 1,335	\$ (66,958)	\$ 36,137
Net loss for the period	-	-	-	-	-	(4,699)	(4,699)
Comprehensive income for the period	-	-	-	-	(964)	-	(964)
Rights offering	34,088,898	4,091	-	-	-	-	4,091
Share issue costs	-	(142)	-	-	-	-	(142)
Expiry of warrants	-	-	(167)	167	-	-	-
Share-based compensation – expensed	-	-	-	25	-	-	25
Share-based compensation – capitalized	-	-	-	6	-	-	6
Balance at December 31, 2016	102,266,694	\$ 98,100	\$ -	\$ 7,640	\$ 371	\$ (71,657)	\$ 34,454

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.**CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS**

(Thousands of Canadian dollars)

(unaudited)

	Notes	Three Months Ended December 31,		Nine Months Ended December 31,	
		2016	2015	2016	2015
Operating activities					
Net (loss) income for the period		\$ (2,288)	\$ 1,413	\$ (4,699)	\$ 1,324
Depletion and depreciation		567	1,084	1,862	3,772
Accretion on decommissioning liability		10	8	27	24
Accretion on credit facility		62	110	219	324
Share-based compensation		-	26	25	74
Unrealized loss (gain) on financial instruments		2,090	(1,663)	6,067	(3,802)
Unrealized foreign exchange (gain) loss		971	(873)	1,056	893
		1,412	105	4,557	2,609
Change in non-cash working capital	10	(478)	830	(685)	1,293
Net cash from operating activities		934	935	3,872	3,902
Investing activities					
Exploration and evaluation expenditures	3	(69)	(174)	(310)	(666)
Petroleum and natural gas properties	4	(1,165)	(1,137)	(4,627)	(2,349)
Changes in non-cash working capital	10	(723)	577	775	(43)
Net cash used in investing activities		(1,957)	(734)	(4,162)	(3,058)
Financing activities					
Proceeds from issuance of shares, net of issuance costs		3,949	-	3,949	-
Repayment of debt		-	-	(1,984)	-
Facility extension fees		(20)	-	(150)	-
Changes in non-cash working capital	10	267	13	354	(30)
Net cash from (used in) financing activities		4,196	13	2,169	(30)
Impact of foreign exchange on cash and cash equivalents		(21)	171	(4)	115
Net increase in cash and cash equivalents		3,152	385	1,875	929
Cash and cash equivalents, beginning of period		1,733	2,293	3,010	1,749
Cash and cash equivalents, end of period		\$ 4,885	\$ 2,678	\$ 4,885	\$ 2,678

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

Notes to Condensed Consolidated Interim Financial Statements (the “financial statements”)

Three and nine months ended December 31, 2016 and 2015

(Tabular amounts are stated in thousands of Canadian dollars except share and per share amounts)
(unaudited)

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 for and development and production of oil and gas reserves in Australia, India and Canada. The condensed consolidated interim financial statements (the “financial statements”) of the Company are comprised of the Company and its wholly-owned subsidiaries Bengal Energy International Inc., Bengal Energy Australia (Pty) Ltd., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. which are incorporated in Canada and Australia respectively. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company’s proportionate interest in such activities.

Bengal’s principal place of business and registered office is located at 1810, 801 6th Ave SW, Calgary, Alberta, Canada, T2P 3W2.

2. BASIS OF PREPARATION

a) Statement of compliance

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”) in accordance with International Accounting Standard (“IAS”) 34, “Interim Financial Reporting”. These condensed consolidated interim financial statements do not include all of the information required for full annual financial statements.

These condensed consolidated interim financial statements are stated in Canadian dollars and have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company for the year ended March 31, 2016.

The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company’s annual filings for the year ended March 31, 2016.

The condensed consolidated interim financial statements were approved and authorized for issuance by the Board of Directors on February 8, 2017.

b) Basis of measurement

These condensed consolidated financial statements have been prepared on a historical cost basis, except for commodity contracts, which are recognized at fair value.

c) Functional and presentation currency

The Company’s presentation currency is Canadian dollars. The functional currency of the Canadian parent entity is Canadian dollars, the functional currency of the Indian subsidiary is US dollars and the functional currency of the Australian subsidiary is Australian dollars.

3. EXPLORATION AND EVALUATION ASSETS (E&E ASSETS)

(\$000s)	Exploration and Evaluation Expenditures
Balance at April 1, 2015	28,245
Additions	651
Acquisition	110
Capitalized share-based compensation	4
E&E impairment loss	(10,475)
Exchange adjustments	1,091
Balance at March 31, 2016	19,626
Additions	310
Capitalized share-based compensation	3
Exchange adjustments	(539)
Balance at December 31, 2016	19,400

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.

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

(\$000s)	Australia
ATP 732P – Tookoonooka	\$ 16,163
ATP 752P - Barta	1,243
Other ⁽¹⁾	2,220
March 31, 2016 (\$000)	\$ 19,626
	Australia
ATP 732P – Tookoonooka	\$ 15,734
ATP 752P - Barta	1,209
Other ⁽¹⁾	2,457
December 31, 2016 (\$000)	\$ 19,400

- (1) Other includes ATP 934P (Barokla), capitalized G&A, share-based compensation and foreign exchange effects on these assets denominated in foreign currencies.

4. PETROLEUM AND NATURAL GAS PROPERTIES

\$000s	Petroleum and Natural Gas Properties	Corporate Assets	Total
<i>Cost:</i>			
Balance at April 1, 2015	38,701	342	39,043
Additions	2,586	-	2,586
Capitalized share-based compensation	6	-	6
Change in decommissioning obligation	(95)	-	(95)
Exchange adjustments	622	2	624
Balance at March 31, 2016	41,820	344	42,164
Additions	4,627	-	4,627
Capitalized share-based compensation	3	-	3
Change in decommissioning obligation	278	-	278
Exchange adjustments	(686)	-	(686)
Balance at December 31, 2016	46,042	344	46,386

\$000s	Petroleum and Natural Gas Properties	Corporate Assets	Total
<i>Accumulated depletion, depreciation and impairment losses:</i>			
Balance at April 1, 2015	11,678	243	11,921
Depletion and depreciation charge	4,519	24	4,543
Impairment	748	-	748
Exchange adjustments	75	2	77
Balance at March 31, 2016	17,020	269	17,289
Depletion and depreciation charge	1,847	15	1,862
Exchange adjustments	75	-	75
Balance at December 31, 2016	18,942	284	19,226
<i>Net carrying value</i>			
At March 31, 2016	24,800	75	24,875
At December 31, 2016	27,100	60	27,160

The calculation of depletion for the quarter ended December 31, 2016 included \$83.6 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2016 - \$83.6 million).

5. CREDIT FACILITY

Facility Agreement – Issued November 12, 2014 (\$000s)		
Gross proceeds		15,364
Total cash fees		(844)
		14,520
Unrealized foreign exchange loss		2,747
		17,267
Accretion		598
Balance at March 31, 2016		17,865
Repayment		(1,984)
Additional borrowing costs		(150)
Unrealized foreign exchange loss		618
Accretion		219
Balance at December 31, 2016		16,568
	December 31, 2016	March 31, 2016
Current portion of credit facility	3,359	10,049
Non-current portion of credit facility	13,209	7,816

In October 2014, Bengal closed its US \$25.0 million secured credit facility with Westpac Institutional Bank and placed an initial draw on November 12, 2014 of US \$14.0 million. On August 26, 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 million. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a three-year term and carries an interest rate of US Libor plus 3.2%.

The credit facility is structured as a reserves-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. In the event that the facility is not further extended, the reduction schedule would commence on December 31, 2017 and occur every six months thereafter until December 31, 2018 with a nominal reduction of \$5 million to the facility limit at each calculation date based on the Company's existing reserve profile. The facility limit at December 31, 2016 is US \$15 million, of which US \$12.5 million is currently drawn. Refer to Note 9(b) for a repayment schedule.

The credit facility's 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. There are no financial covenants associated with this credit facility. The Company was in compliance with the stated covenants at December 31, 2016.

6. DECOMMISSIONING AND RESTORATION LIABILITY

The total decommissioning and restoration obligations were estimated by management based on the estimated costs to reclaim and abandon the wells, well sites and certain facilities based on the Company's contractual requirements.

Changes to decommissioning and restoration obligations were as follows:

(\$000s)	December 31, 2016	March 31, 2016
Decommissioning liabilities, beginning of period	1,422	1,454
Revision	-	(95)
Decommissioning expenditures	-	-
Additions	278	-
Accretion	27	33
Exchange adjustments	(41)	30
Decommissioning liabilities, end of period	1,686	1,422

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 December 31, 2016 is approximately \$2.2 million (March 31, 2016 – \$1.9 million) which will be incurred between 2019 and 2044. An inflation factor of 1.5% - 1.7% and a risk-free discount rate ranging between 1.23% and 2.49% have been applied to the decommissioning liability at December 31, 2016.

7. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares with no par value.

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

(b) Issued:

The following provides a continuity of share capital:

(\$000s)	Number of Shares	Amount
Balance at March 31, 2015 and 2016	68,177,796	94,151
Issued on exercise of rights offering	34,088,898	4,091
Share issue costs	-	(142)
Balance at March 31, 2016	102,266,694	98,100

The Company completed a rights offering (the "Rights Offering") which closed on December 29, 2016. Under the terms of the Rights Offering, each registered holder of Common Shares, at the close of business on December 2, 2016, received one Right for each Common Share held. Two Rights, plus the sum of \$0.12 (the "Subscription Price"), entitled the holder thereof to acquire one Common Share. The Subscription Price was at a discount to the closing trading price of \$0.14 at December 2 and December 29, 2016. The Rights Offering resulted in 34,088,898 common shares being issued (16,056,853 common shares were issued to officers and directors) for total proceeds of \$4.1 million. Share issuance costs of \$142 were incurred related to the Rights Offering and have been recognized in the carrying value of share capital on the consolidated statement of financial position.

(c) **Share-based compensation – stock options:**

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2016	4,357,500	\$ 0.72
Expired	(770,000)	1.30
Outstanding at December 31, 2016	3,587,500	\$ 0.59
Exercisable at December 31, 2016	2,693,756	\$ 0.73

(d) **Per share amounts:**

Loss per share is calculated based on net loss and the weighted-average number of common shares outstanding.

(\$000s)	Three months ended December 31,		Nine months ended December 31,	
	2016	2015	2016	2015
Income (loss) for the period	\$(2,288)	\$ 1,413	\$(4,699)	\$ 1,324
Weighted average number of common shares (basic)	68,919	68,178	68,426	68,178
Weighted average number of common shares (diluted)	68,919	68,178	68,426	68,283
Basic & diluted income (loss) per share	\$ (0.03)	\$ 0.02	\$ (0.07)	\$ 0.02

For the three and nine months ended December 31, 2016, there were 3,587,500 (March 31, 2016 – 4,357,000) options considered anti-dilutive.

8. FINANCE INCOME/EXPENSES

(\$000s)	Three months ended December 31,		Nine months ended December 31,	
	2016	2015	2016	2015
Interest income	1	2	4	7
Accretion on decommissioning obligations	(10)	(8)	(27)	(24)
Letter of credit charges	-	-	(55)	14
Interest on credit facility	(256)	(333)	(769)	(963)
Change in fair value of VARs	-	3	-	2
Finance income (expenses)	(265)	(336)	(847)	(964)

9. 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 December 31, 2016, Bengal's receivables consisted of \$2.8 million (March 31, 2016 - \$2.6 million) from joint venture partners and \$nil million (March 31, 2016 - \$0.6 million) of other trade receivables of which \$2.3 million has been subsequently collected.

In Australia, production is purchased by a consortium led by one of Australia's largest public oil and gas companies which is also the operator of Bengal's production. Bengal has a Crude Oil Purchase Agreement with this 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 December 31, 2016, (March 31, 2016 - \$nil million). 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 December 31, 2016 and did not provide for any doubtful accounts, nor was it required to write-off any receivables during the nine months ended December 31, 2016. Exposure to the carrying value of its financial instruments relates to the Company's commodity-based derivatives held by Westpac Banking Corporation, which carries a Standard & Poor's credit rating of AA-. Management considers the credit risk of these instruments to be adequately mitigated by the credit rating of their holder; therefore, no allowance has been established.

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 accounts payable and accrued liabilities, financial instrument liability, and credit facility and amounted to \$19.9 million at December 31, 2016 (March 31, 2016 - \$20.6 million).

At December 31, 2016 the Company had working capital of \$3.3 million, including cash and short-term deposits of \$4.9 million and restricted cash of \$0.1 million, compared to a working capital deficiency of \$0.4 million at March 31, 2016 and working capital deficiency of \$1.5 million at December 31, 2015. The Company has an additional US \$2.5 million of available undrawn debt under its Westpac credit facility.

The majority of the Company's oil sales are benchmarked on dated Brent prices which averaged US \$46.96/bbl for the nine months ended December 31, 2016. 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. 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 appropriate. Under the current commodity price environment, the Company has no plans to use its internal source of cash to fund exploration activities. These are expected to be financed through farm-out or alternative financing sources.

The table below indicates the current payment schedule for the credit facility:

Credit facility (US\$000s)	
Fiscal year 2018	2,500
Fiscal year 2019	10,000
	12,500

(c) Market risk:

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk. The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates 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 exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives Canadian dollars for sales in Canada, U.S. dollars for Australian oil sales and incurs expenditures in Australian, Canadian and U.S. currencies. Having sales and expenditures denominated in three currencies spreads the impact of individual currency fluctuations.

The Company may enter into derivative foreign currency contracts in order to manage foreign currency exchange rate risk, but has not done so to date.

The table below shows the Company's exposure to foreign currencies for its financial instruments:

As at December 31, 2016				
(\$000s)				
	CAD	AUD	USD	Total
Cash and short-term deposits	4,205	96	584	4,885
Restricted cash	140	-	-	140
Accounts receivable	30	2,819	-	2,849
Accounts payable and accrued liabilities	(368)	(2,440)	(7)	(2,815)
Credit facility	-	-	(16,568)	(16,568)
Fair value of financial instruments	-	-	915	915
	4,007	475	(15,076)	

Commodity Price Risk

Commodity price risk is the risk that the fair value or 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 Dated Brent reference price, which trades at a premium to WTI.

At December 31, 2016, the following derivative contracts were outstanding and recorded at estimated fair value:

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US\$/bbl)	Price Ceiling (US\$/bbl)
January 1, 2017 – May 31, 2017	Oil - Swap	31,728	80.00	80.00
January 1, 2017 – May 31, 2017	Oil – Put option	25,957	80.00	-
		Oil - swap	Oil – put	Total
		934	766	1,700
		-	-	-
		934	766	1,700

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US\$/bbl)	Price Ceiling (US\$/bbl)
July 1, 2017 – December 31, 2018	Oil - Swap	67,373	47.00	47.00
July 1, 2017 – December 31, 2018	Oil – Put option	67,373	47.00	-
		Oil - swap	Oil – put	Total
		(338)	55	(283)
		(687)	185	(502)
		(1,025)	240	(785)

A US \$1.00 increase in the future crude oil price per barrel would result in an approximate US \$192,000 decrease in the fair value of financial instruments at December 31, 2016 while a US \$1.00 decrease would result in an increase of approximately US\$192,000 in the fair value of the instruments.

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 December 31, 2016 as the funds are not invested in an interest-bearing instrument. The Company's credit facility carries a floating interest rate based on quoted US dollar LIBOR rates. The Company had no interest rate derivatives at December 31, 2016.

For the nine months ended December 31, 2016, a 1% increase in US Libor would increase interest expense by \$123.

10. CHANGES IN NON-CASH WORKING CAPITAL

Nine months ended (\$000s)	December 31, 2016	December 31, 2015
Accounts receivable	338	237
Prepaid expenses and deposits	(18)	125
Accounts payable and accrued liabilities	145	865
Impact of foreign exchange	(21)	(7)
Total	444	1,220
Relating to:		
Operating	(685)	1,293
Financing	354	(30)
Investing	775	(43)
Total	444	1,220

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

Nine months ended (\$000s)	December 31, 2016	December 31, 2015
Cash interest paid	532	892
Cash interest received	4	7

11. COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. Additional commitments are reflected where the Company has agreed with joint operating partners to proceed with activities. The costs of these activities are based on minimum work budgets included in bid documents and have not been provided for in the financial statements. Actual costs will vary from budget.

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. Currently the Company holds a 71.43% operating interest in this permit. Work program consists of 200 kilometers of 3D seismic and up to three wells, which would require a capital spend of \$2.1 million in 2017 and a further \$2.1 million in 2018 net to Bengal.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD\$) ⁽¹⁾
Onshore Australia – ATP 934P	200 km ² of 3D seismic and up to three wells	March 2021	\$ 16.1

⁽¹⁾ Translated at December 31, 2016 at an exchange rate of AUS \$1.00 = CAD \$0.9671.

At December 31, 2016 the Company had the following lease commitment for office space in Canada.

(\$000s)					
October 2016 to March 2017	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	66	66	-	-	-

Subsequent to December 31, 2016, the Company committed to a new lease for office space in Canada from April 1, 2017 through November 30, 2023 as follows:

(\$000s)					
April 2017 to November 2023	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	943	13	311	311	308

12. SEGMENTED INFORMATION

As at December 31, 2016, the Company has three reportable operating segments being the Australian, Canadian and India oil and gas operations.

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 central administration costs and 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.

For the nine months ended December 31, 2016 (\$000s)				
	Australia	Corporate	India	Total
Revenue	7,115	-	-	7,115
Interest revenue	3	1	-	4
Interest expense	769	-	-	769
Depletion and depreciation	1,848	14	-	1,862
Net earnings (loss)	(3,657)	(864)	(178)	(4,699)
Exploration and evaluation expenditures	310	-	-	310
Petroleum and natural gas property expenditures	4,627	-	-	4,627
As at December 31, 2016 (\$000s)				
Petroleum and natural gas properties				
Cost	41,750	4,637	-	46,387
Accumulated impairment loss	(796)	(310)	-	(1,106)
Accumulated depletion and depreciation	(13,854)	(4,267)	-	(18,121)
Net book value	27,100	60	-	27,160
Exploration and evaluation assets				
Exploration and evaluation assets	28,476	-	8,484	36,960
Accumulated impairment losses	(9,076)	-	(8,484)	(17,560)
Net book value	19,400	-	-	19,400
For the nine months ended December 31, 2015 (\$000s)				
	Australia	Corporate	India	Total
Revenue	8,934	-	-	8,934
Interest income	6	1	-	7
Interest expense	963	-	-	963
Depletion and depreciation	3,753	19	-	3,772
Net income (loss)	2,563	(979)	(260)	1,324
Exploration and evaluation expenditures	646	-	20	666
Petroleum and natural gas property expenditures	2,349	-	-	2,349
As at December 31, 2015 (\$000s)				
Petroleum and natural gas properties				
Cost	37,860	4,637	-	42,497
Accumulated impairment losses	(796)	(310)	-	(1,106)
Accumulated depletion and depreciation	(10,413)	(4,247)	-	(14,660)
Net book value	26,651	80	-	26,731
Exploration and evaluation assets				
Exploration and evaluation assets	34,504	-	8,757	43,261
Accumulated impairment losses	(11,455)	-	(1,308)	(12,763)
Net book value	23,049	-	7,449	30,498

For the three months ended December 31, 2016 (\$000s)				
	Australia	Corporate	India	Total
Revenue	2,325	-	-	2,325
Interest revenue	-	1	-	1
Interest expense	256	-	-	256
Depletion and depreciation	563	4	-	567
Net income (loss)	(2,011)	(259)	(18)	(2,288)
Exploration and evaluation expenditures	69	-	-	69
Petroleum and natural gas property expenditures	1,165	-	-	1,165
For the three months ended December 31, 2015 (\$000s)				
	Australia	Corporate	India	Total
Revenue	1,838	-	-	1,838
Interest revenue	1	1	-	2
Interest expense	333	-	-	333
Depletion and depreciation	1,078	6	-	1,084
Net earnings (loss)	1,833	(320)	(100)	1,413
Exploration and evaluation expenditures	174	-	-	174
Petroleum and natural gas property expenditures	1,137	-	-	1,137

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Johnson Winter Slattery • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

INVESTOR RELATIONS

5 Quarters Investor Relations, Inc. • Calgary, 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

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

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
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

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