Bengal ENERGY LTD.

international exploration & production

2015 Annual Report

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

Bengal's 2015 fiscal year was the most active period in our history, with results from our two-phased Cuisinier drilling campaign contributing to a 51% increase in our proved plus probable ("2P") reserve base over fiscal year end 2014. New reserve additions from our successful drilling and development program effectively replaced more than 12 times our 2015 annual production volumes. Despite a significant downturn in global crude oil prices facing the industry, on the strength of Bengal's asset base we were able to solidify our financial flexibility by finalizing a US$25 million secured credit facility with Westpac Institutional Bank of Australia. Operationally and financially, I am very pleased with the progress Bengal has made in 2015 to further develop and grow our asset base, while positioning the Company to deliver long-term value.

As a direct result of our fiscal 2015 activities in the Cuisinier oil pool on the Barta block in Australia's Cooper Basin, the net present value discounted at 10% (NPV10) of Bengal's 2P reserves increased 17% over the prior year, and was assessed at $118 million by our independent reserve evaluators. This is a clear demonstration of the inherent value in Bengal's asset base, and the magnitude of its potential, particularly in light of the dramatic decrease in world oil prices year over year. Our team's technical capabilities, consistent execution of strategy and unwavering value-focus have led to the successful growth and delineation of the Cuisinier pool and its related asset value for Bengal.

While crude oil prices have shown moderate improvement from their dramatic lows in early calendar 2015, the global outlook for commodity prices remains challenged. However, Bengal is very well-positioned relative to many of our North American energy sector peers. As a result of our high quality asset base, which produces ultra-light oil and commands a premium price to the Brent benchmark, coupled with Australia's favourable and predictable royalty regime, our Australian netbacks averaged CDN$89.43/bbl for the 2015 fiscal year. To further underpin our future revenues and in concert with our new US$25 million secured credit facility, Bengal entered into a combination of fixed future swap and put positions on approximately 269,000 barrels effective December 2014 through June 2017, with an attractive floor price of US $80 per barrel. This robust and advantageous hedging position serves to further support Bengal's revenue and funds flow during periods of commodity price volatility.

Bengal's 2015 capital program was primarily directed to the development and appraisal of the Cuisinier oil pool where Bengal and our joint venture parties successful drilled and completed four development wells from late March 2014 through early May 2014. The Phase Two drilling campaign also included one successful exploration well at Wompi, three appraisal wells and two development wells, Cuisiner-20 and Cuisnier-21 on the ATP 752 Barta Block within the Cuisinier field. Cuisiner-20 and Cuisnier-21 are currently being tied-in by the operator. Through the first three months of fiscal 2016, our production has been relatively stable relative to the previous calendar quarter, averaging approximately 525 boepd.

In addition to contributing new production volumes, the new Cuisinier-21 development well is significant because it successfully expanded the lowest known oil level in the Cuisinier structure by establishing a 42-plus meter oil column. This expansion further increases the areal extent of the Cuisinier pool and provides new opportunities for future drilling and development. The success of our 2015 drilling program has enhanced our understanding of the geological features in the area and resulted in record year-end reserve assignments for Bengal by our independent reserve evaluators.

Bengal remains catalyst-rich as we move into fiscal 2016 with a combination of continued development and exploration activities. At Wompi, Bengal holds a 38% working interest and with our JV parties, are preparing for the completion and testing of our newest gas discovery. In early calendar 2016, the JV will complete and test the commerciality of the Nubba-1 exploration well. While the Phase Two exploration well encountered multiple oil shows, we are even more excited by its potential as a future natural gas producer, showing up to 6 metres of gas pay. The discovery has the potential to provide another significant target-rich play for future development.

Bengal and our Joint Venture Partner, Beach Energy Ltd ("Beach"), are planning to drill a second well at our Tookoonooka asset, the cost for which Bengal will be fully carried. Beach has completed the acquisition; processing and preliminary interpretation of a 300 square kilometre 3D seismic survey and the Joint Venture will identify potential drilling locations in advance of drilling in calendar mid-2016. This area could provide an important driver for Bengal, offering new near-term production volumes and revenue, as well as extensive future drilling locations to support growth over the longer term.

In our onshore India block at CY-ONN-2005/1, Bengal holds a 30% working interest in 946 square kilometres (233,000 acres), and we continue to coordinate with our partners, Gas Authority of India Ltd. ("GAIL") and Gujarat State Petroleum Corporation to advance plans for the drilling of three exciting exploration wells. GAIL, the operator, is working with various local stakeholders and government bodies to obtain the necessary approvals to proceed, with current expectations for drilling the first well at the earliest, in late calendar 2015.

Following up on Bengal's largest ever capital program, and in response to the currently uncertain commodity price environment, our primary focus for fiscal 2016 will be to ensure prudent capital investment supported by a thorough analysis of development, appraisal and exploration opportunities, with continued cost reduction efforts.

In response to a weakened commodity price environment, we anticipate a number of production acquisition and other strategic opportunities to arise over the coming quarters. Bengal will continue to examine and evaluate potential opportunities and transactions with the objective of adding to production, reserves and funds flow, all of which support enhanced shareholder value. We will continue development and appraisal drilling at our core properties in Cuisinier, expected to drive near-term and operating income while paving the way for future expanded development.

Bengal has taken steps to weather the current commodity price downturn by improving our financial flexibility, establishing an attractive hedge position, and maintaining a responsible approach to our operations. I want to thank our strong and supportive Board, our hard-working and skilled technical team, as well as each of our shareholders for your support as we grow and further unlock the value of Bengal Energy.

Sincerely,

Chayan Chakrabarty

Chayan Chakrabarty
President & CEO

Note: this Message to Shareholders contains forward-looking statements and is subject to the forward-looking statement disclaimer in the Management's Discussion & Analysis for the Years Ended March 31, 2015 and 2014.

FISCAL 2015 HGHLIGHTS

Financial Highlights:

- **Reserves Growth Continues** – The independent third party year-end reserves evaluation to March 31, 2015 shows a 31% and 51% year-over-year corporate Proved ("1P") and Proved plus Probable ("2P") reserves increase, respectively. 1P reserves are now 2.2 million barrels and 2P reserves are now 5.7 million barrels of high quality, high netback 52 degree gravity light oil. These increases were primarily driven by the successful drilling program conducted throughout the year on the Cuisinier asset. Based on 1P and 2P reserves additions, Bengal has replaced approximately 4.0 times and 12.0 times its annual production, respectively.
- **Hedging in place through June 2017** – Effective December 2014, the Company entered into a combination of fixed for future swaps and put positions for approximately 269,000 barrels in total through to June 2017 with a floor price of US $80 per barrel. Since December 2014, the hedging program has resulted in a realized gain of $0.9 million and carries an unrealized fair value of $5.0 million.
- **Revenue** – Bengal generated revenue of approximately $3.4 million in the fourth quarter of fiscal 2015 compared with $3.9 million in the third quarter of fiscal 2015. The difference is primarily due to a decrease in benchmark commodity prices and is partially offset by the Company's hedging positions. Revenue was 36% lower than the $5.3 million generated during the fourth quarter of fiscal 2014. For the full fiscal year ended 2015, Bengal generated revenue of approximately $15.4 million, which is a 21% decrease over fiscal 2014. The decrease was again driven by lower realized pricing for crude oil.
- **Funds Flow from Operations(1)** – Bengal generated funds flow from operations of $0.9 million in Q4 2015, being the quarter ended March 31, 2015, compared to $2.2 million during Q4 2014 and $1.3 million generated in Q3 2015, due to lower netbacks associated with declining benchmark crude prices. The full fiscal year ended 2015 funds flow from operations was $4.6 million, versus $8.2 million generated during the fiscal year ended March 31, 2014.
- **Earnings** – Bengal reported a net loss of $3.2 million during the fiscal year ended 2015, compared to a net income of $0.2 million in the prior year due to the impact decreased crude oil prices on funds from operations as well as the $3.2 million impairment of its wholly owned drilling rig and $1.8 million of foreign exchange losses. When the impact of unrealized foreign exchange losses and unrealized hedging gains are eliminated, Bengal's 2015 annual adjusted net loss(1) was $6.1 million compared to annual adjusted net earnings of $0.02 million in the fiscal year ended March 31, 2014.
- **Additional Financial Flexibility** – On October 24, 2014, Bengal finalized its US $25.0 million secured credit facility with Westpac Institutional Bank of Australia. An initial draw of US $14.0 million was used to repay the Company's existing $8.0 million aggregate principal amount of notes and to fund a portion of the Cuisinier Phase Two development drilling program.

2015 Operational Highlights:

- **Production Volumes** – Production in the fourth quarter of 2015 averaged 525 barrels of oil equivalent per day ("boepd"), a 4% increase from the fourth quarter of 2014, and a 9% decrease from the previous quarter due to natural declines. Full year 2015 production increased 3% to 480 boepd compared to 468 boepd produced in 2014 as a result of incremental production from the Cuisinier Phase One drilling program. Incremental production from the 2014 Cuisinier drilling

[1] See non-IFRS measurements section on page 6 to this MD&A

program has been partially offset by the unexpected increase in water cut at the Cuisinier-6 well, which underwent a work over program in April 2015 in an attempt to restore production.

Production has been relatively stable through the first quarter of fiscal 2016, averaging 525 boepd, with two new producing wells coming online in June 2015.

- **Cuisinier Drilling Campaign** – From late March 2014 to early May 2014, Bengal and its joint venture parties ("JV") carried out the first of its calendar 2014 two-phase drilling campaign at Cuisinier. The four Phase One development wells targeted the oil-bearing Cretaceous Murta Formation and were drilled with 100% success**.**

  The Phase Two drilling campaign included three appraisal wells and two development wells at the ATP 752 Barta Block Cuisinier oil field. The JV is in the process of tying-in the two development wells, Cuisiner-20, and Cuisnier-21.

- **Cuisinier-21** – This development well tested the northwest flank of the Cuisinier structure and came in structurally as predicted; testing 100% clean oil on perf at an estimated rate of 380 boepd. This well has now established an oil column of at least 42 meters and further increasing the areal extent of the Cuisinier pool.

- **Cuisinier-6** – During the month of April 2015, the operator completed production logging on this well and set a bridge plug to isolate the producing Murta formation from the deeper Namur formation aquifer. The performance of this well will be monitored closely in the coming months to determine if isolation was complete.

- **Cuisinier-17 and -19** – As previously announced, the Cuisinier-17 and Cuisinier-19 have been suspended pending finalization of an appropriate stimulation program. The operator is in the process of developing a fracture stimulation program for a number of wells at Cuisinier that, based on results, could potentially include the Cuisinier-17 and Cuisinier-19 wells in the future.

- **ATP 934 Barrolka Permit** – On March 1, 2015, this gas prone 361,268 acre block was awarded to the Bengal operated JV by the Minister of the Department of Natural Resources and Mines of the Queensland Government. In addition, effective April 1, 2015, Bengal increased its ownership in the permit to 80% through the acquisition of the interest held by one of its joint venture parties. The remaining joint venture partner, effective June 19, 2015 exercised its option to purchase 8.6% of this interest; therefore Bengal's current working interest is 71.4%. As operator, Bengal is currently in discussions with the Queensland Government and hopes to finalize a work program and budget for this gas focused permit in the near future.

- **Wompi Exploration** – Bengal and its JV parties completed drilling operations of the Nubba-1 exploration well. The well encountered multiple oil shows within the Jurassic, as well as up to 6 meters of Permian Toolachee Formation gas pay. Completion and testing of this gas discovery will confirm rates and commerciality early in calendar 2016. Bengal has 38% in the Wompi block and the Nubba well.

- **ATP 732 Tookoonooka Permit** – Beach Energy Ltd. farmed in to this Permit in 2011 and have now completed the acquisition, processing and preliminary interpretation of the 300 square kilometre Nassarius 3D seismic survey. Additional pre-stack depth migration ("PSDM") was required to better image some of the leads that have been defined. The processing of the PSDM data has now been completed and the final interpretation is due to commence imminently. The next phase of drilling will be finalized upon completion of interpretation.

- **Onshore India Drilling Plan** – At Bengal's onshore India block situated within the Cauvery Basin (CY-ONN-2005/1 – 30% WI), the Company continues to coordinate with its partners, Gas Authority of India Ltd. ("GAIL") and Gujarat State Petroleum Corporation, for the drilling of three exploration wells. GAIL, the operator, continues to negotiate with various stakeholders and government bodies that provide the necessary approvals to proceed. The drilling of the first of three exploration wells is expected to commence no earlier than in late calendar 2015.

MANAGEMENT'S DISCUSSION AND ANALYSIS – JUNE 18, 2015

Bengal's producing assets are predominantly 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 Basin in its infancy in terms of appraisal and development, and 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.

With oil pricing benchmarked to Brent, Bengal's realized operating netbacks from Australia have averaged over C $56.10/bbl for the twelve months ending March 31, 2015. This competitive cost environment coupled with a growing production base contributed to the Company's positive funds flow from operations through fiscal 2015.

OUTLOOK

AUSTRALIA

ATP 752 Barta Block Cuisinier

The Barta Joint Venture ("JV") completed Phase Two of the Cuisinier drilling campaign and tied in two of four development locations in June 2015. The two remaining suspended wells as well as several other marginal producers in the field are currently being evaluated as candidates for a 2015 fracture stimulation program. Given the current commodity price climate, the primary focus for the Cuisinier production license will be low cost high yield development projects, such as fracture stimulation as well as overall field evaluation. This field evaluation will result in a development plan focused on the continued expansion of pool boundaries as well as increasing field production by targeting lower risk high productivity locations.

ATP 732 Tookoonooka Block

In Bengal's Tookoonooka permit (ATP 732 - WI 50%), which is located in the emerging East Flank oil fairway of the Cooper Basin, the Company is partnered with Beach Energy Ltd. ("Beach"). Following the ongoing seismic interpretation, the joint venture is expected to identify drilling locations in advance of drilling mid-2016.

ATP 752 Wompi

The Nubba-1 well, which encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas pay is expected to be evaluated late 2015 or early 2016. Pressure testing as well logging suggests that this Toolachee gas well could be part of a gas column which 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. With positive test results a Petroleum Production Lease will be applied for which will allow long term production to begin. 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 offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential.

SUMMARY

Following up on the Company's largest ever capital program, and in response to the currently uncertain commodity price environment, the primary focus of fiscal 2016 will be prudent capital investment and thorough analysis of development, appraisal and exploration opportunities.

The current depressed commodity price environment has caused some competitors to refocus their strategy and operations. As a result, the company expects a number of production acquisition and other strategic opportunities to arise over the next several quarters. Bengal continues to examine and evaluate potential opportunities through various industry and financial entities with the objective of adding to Bengal's production and enhancing shareholder value. It is not possible to assess the likelihood of success in any such endeavor at this time.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2015	2014	% Change	**2015**	2014	% Change
Revenue						
Oil	**$ 3,359**	$ 5,174	(35)	**$ 15,395**	$ 19,480	(21)
Natural gas	**23**	87	(74)	**246**	274	(10)
Natural gas liquids	**(4)**	11	(136)	**28**	68	(59)
Total	**$ 3,378**	$ 5,272	(36)	**$ 15,669**	$ 19,822	(21)
Royalties	**202**	407	(50)	**1,057**	1,334	(21)
Realized gain on financial instruments	**717**	-	N/A	**981**	-	N/A
% of revenue	**6.0**	7.7	(22)	**6.7**	6.7	-
Operating & transportation	**1,727**	1,496	15	**6,247**	5,290	18
Operating netback(1)	**$ 2,166**	$ 3,369	(36)	**$ 9,256**	$ 13,198	(37)
Funds from (used in) operations:(2)	**939**	2,218	(58)	**4,589**	8,183	(43)
Per share ($) (basic & diluted)	**0.01**	0.03	(67)	**0.07**	0.13	(46)
Net income (loss):	**(1,052)**	(1,804)	(42)	**(3,172)**	150	N/A
Per share ($) (basic & diluted)	**(0.02)**	(0.03)	(33)	**(0.05)**	-	-
Adjusted net (loss) earnings:	**(474)**	(1,936)	(76)	**(6,052)**	23	N/A
Per share ($) (basic & diluted)	**(0.01)**	(0.03)	33	**(0.09)**	-	N/A
Capital expenditures	**$ 2,410**	$ 2,048	18	**$ 13,463**	$ 16,647	(19)
Volumes						
Oil (bpd)	**506**	472	7	**452**	433	4
Natural gas (mcfd)	**114**	180	(37)	**164**	201	(18)
Natural gas liquids (boepd)	**-**	2	(100)	**1**	2	(50)
Total (boepd @ 6:1)	**525**	504	4	**480**	468	3
Netback(1) ($CDN/boe)						
Revenue	**$ 71.53**	$ 116.24	(39)	**$ 89.43**	$ 115.94	(23)
Realized gain on financial instrument	**15.18**	-	-	**5.09**	-	-
Royalties	**4.28**	8.97	(52)	**6.03**	7.80	(23)
Operating & transportation	**36.57**	32.99	11	**35.65**	30.94	15
Operating netback	**$ 45.86**	$ 74.28	(38)	**$ 52.84**	$ 77.20	(32)

(1) Operating netback is a non-IFRS measure. Netback per boe is calculated by dividing the revenue and costs in total for the Company 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 6.
(3) Adjusted net earnings is a non-IFRS measure. The comparable IFRS measure is net income. A reconciliation of the two measures can be found in the table on page 7.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the twelve months ended March 31, 2015 and 2014. The terms “current quarter” and “the quarter” are used throughout the MD&A and in all cases refer to the period from January 1, 2015 through March 31, 2015. The terms “prior year’s quarter” and “2014 quarter” are used throughout the MD&A for comparative purposes and refer to the period from January 1, 2014 through March 31, 2014.

The fiscal year for the Company is the twelve-month period ended March 31, 2015. The terms “fiscal 2015,” “current year” and “the year” are used in the MD&A and in all cases refer to the period from April 1, 2014 through March 31, 2015. The terms “previous year,” “prior year” and “fiscal 2014” are used in the MD&A for comparative purposes and refer to the period from April 1, 2013 through March 31, 2014. The term YTD means year-to-date.

For the purpose of calculating unit costs, natural gas volumes have been converted to barrels of oil equivalent (“boe”) using a conversion ratio of six thousand cubic feet (“mcf”) of natural gas to one barrel (“bbl”) of oil. This conversion ratio of 6:1 is based on an energy equivalency conversion for the individual products, primarily at the burner tip, and is not intended to represent a value equivalency at the wellhead. Such disclosure of boe may be misleading, particularly if used in isolation.

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

Non-IFRS Measurements

Bengal uses measurements primarily based on IFRS as issued by the IASB and also certain secondary non-IFRS measurements commonly used in the oil and gas industry. The non-IFRS measurements included in this Management’s Discussion and Analysis are funds from operations, funds from operations per share, adjusted net earnings, adjusted net earnings per share and operating netbacks which do not have any standardized meaning under IFRS and are referred to as non-IFRS measures.

Operating netbacks assists management and investors to evaluate the specific operating performance of the Company by product and is equal to total revenue 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. Total boe is calculated by multiplying the daily production by the number of days in the period.

Funds from operations is a non-IFRS measure, which should not be considered an alternative to “Net cash from operating activities” and is comprised of cash from operating activities as presented in the consolidated statement of cash flows adding changes in non-cash working capital and the settlement of decommissioning liabilities. 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 and is presented in the Company’s’ financial reports to assist management and investors in analyzing the Company’s operating performance. 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.

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

	Three Months Ended March 31			Twelve Months Ended March 31		
$000s	**2015**	2014	% Change	**2015**	2014	% Change
Cash flow from (used in) operating activities	**1,031**	2,106	(51)	**6,921**	7,591	(9)
Changes in non-cash working capital	**(92)**	112	(182)	**(2,332)**	592	(494)
Funds from (used in) operations	**939**	2,218	(58)	**4,589**	8,183	(43)

Adjusted net earnings is a non-IFRS measure, which should not be considered an alternative to “Net (loss) income” as presented in the consolidated statement of (loss) / income and comprehensive (loss)/ income 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 (loss) income 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 net income (loss) per share.

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

	Three Months Ended March 31			Twelve Months Ended March 31		
$000s	**2015**	2014	% Change	**2015**	2014	% Change
Net (loss) income	**(1,052)**	(1,804)	(42)	**(3,172)**	150	(2,215)
Unrealized gain on financial instruments	**(440)**	-	N/A	**(4,962)**	-	N/A
Unrealized foreign exchange loss	**1,018**	(132)	871	**2,082**	(127)	507
Adjusted net earnings	**(474)**	(1,936)	76	**(6,052)**	23	N/A

RESULTS OF OPERATONS - AUSTRALLIA

Production, Commodity Pricing and Sales

The following table outlines Bengal’s production volumes for the periods indicated:

	Three Months Ended March 31			Twelve Months Ended March 31		
	2015	2014	% Change	**2015**	2014	% Change
Oil Production (bopd)	**506**	472	7	**452**	433	4
($000s)						
Oil Sales	**3,359**	5,174	(35)	**15,395**	19,480	(21)
Realized gain on financial instrument	**717**	-	-	**891**	-	-
Royalties	**201**	396	(49)	**1,026**	1,305	(21)
Operating expenses	**1,683**	1,422	18	**6,014**	5,049	19
Operating netback ($000s)	**2,192**	3,356	(35)	**9,246**	13,126	(30)
Oil Sales ($/bbl)	**73.08**	121.68	(39)	**93.40**	123.31	(24)
Realized gain on financial Instrument	**15.75**	-	-	**5.41**	-	-
Royalties ($/bbl)	**4.42**	9.31	(53)	**6.22**	8.26	(25)
Operating expenses ($/bbl)	**36.98**	33.44	11	**36.49**	31.96	14
Operating netback ($/bbl)	**48.15**	78.93	(59)	**56.10**	83.09	(32)

Production

Production gains for both the year and quarter ended March 31, 2015 are the result of four successful development wells drilled as part of the 2014 phase 1 drilling campaign which were brought online during August and September 2014 adding an incremental 325 bopd of production net to Bengal during Q4 2015. These production additions were partially offset by natural declines as well as continued production disruptions at the Cuisinier 6 well, which has been producing close to 100% water since May 2014. The operator completed a work over operation in May 2015 by setting a bridge plug to isolate a potential water source below the Murta formation and the well's potential productivity is being evaluated over the next few months.

Pricing

The price received for Bengal's Australian oil sales is based 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 USD $3.44/bbl over Brent for the twelve months ended March 31, 2015 (2014 – USD $6.34).

Realized crude oil prices decreased by 24% for the year and 39% for the quarter ended March 31, 2015 relative to the prior year and quarter due to a respective 20% and 50% decrease in Benchmarked Brent crude prices. The Company's oil sales are based on a premium to Brent benchmark pricing denominated in US dollars, therefore the depreciation in the value of the Canadian dollar relative to the US dollar has partially offset the effect of decreased Brent pricing during Q4 2015.

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

Prices and Marketing	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
Average Benchmark Price	**2015**	2014	% Change	**2015**	2014	% Change
Bengal realized crude oil price before realized gain on financial instruments ($CAD/bbl)	**$ 73.80**	121.68	(39)	**$ 93.40**	$ 123.31	(24)
Realized gain on financial instrument ($CAD/bbl)	**15.75**	-	N/A	**5.41**	-	N/A
Bengal realized crude oil price including realized gain on financial instruments ($CAD/bbl)	**89.55**	121.68	(26)	**98.81**	123.31	(20)
Dated Brent oil ($CAD/bbl)	**66.83**	118.81	(44)	**97.31**	112.92	(14)
Dated Brent oil ($US/bbl)	**53.97**	108.14	(50)	**85.43**	107.54	(21)
Number of CAD$ for 1 AUS$	**0.97**	0.99	(2)	**0.99**	0.98	1
Number of CAD$ for 1 US$	**1.24**	1.10	13	**1.14**	1.05	9

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 income.

The company has managed the price application to production volumes through the following contracts:

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US$/bbl)	Price Ceiling (US$/bbl)
Apr 1, 2015 – May 31, 2017	Oil - Swap	130,252	80.00	80.00
Apr 1, 2015 – May 31, 2017	Oil – Put option	106,569	80.00	-

The fair value of the financial contracts outstanding as at March 31, 2015 is an estimated asset of $5.0 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 and twelve months ended March 31, 2015, the derivative commodity contracts resulted in realized gains of $0.7 million (2014 – $nil) and $0.9 million (2014 - $nil) and unrealized gains of $0.5 million (2014 - $nil) and $5.0 million (2014 - $nil).

Royalties

Royalties ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2015	2014	% Change	**2015**	2014	% Change
Royalty Expense	**201**	396	(49)	**1,026**	1,305	(21)
$/bbl	**4.42**	8.26	(53)	**6.22**	8.73	(29)
% of revenue	**6**	8	(25)	**7**	7	-

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 transportation and operating costs resulting in an effective rate of less than 10%.

Royalties have decreased as a percentage of revenue for Q4 2015 compared to Q4 2014 primarily due to an increase in allowable transportation expenditures claimed by the operator. For the year ended March 31, 2015 compared to the prior year, royalties have remained consistent as a percentage of revenue.

Operating & Transportation Expenses

Operating & trans. expenses ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2015	2014	% Change	**2015**	2014	% Change
Operating	**303**	287	6	**1,050**	965	9
Transportation	**1,380**	1,135	22	**4,964**	4,084	22
	1,683	1,422	18	**6,014**	5,049	19
Operating - $/bbl	**6.66**	6.75	(1)	**6.37**	6.11	4
Transp. - $/bbl	**30.32**	26.69	14	**30.12**	25.85	17
	36.98	33.44	11	**36.49**	31.96	14

The increase in operating and transportation costs for the current year and quarter were due primarily to increased production volumes as operating costs per barrel have remained consistent when compared to the prior year and quarter ended March 31, 2014.

Transportation costs on a boe basis have increased from prior quarter and year ended March 31, 2015 due to commissioning of the Cuisinier to Cook pipeline and subsequent connection of this line to the Cook facility and the Cook to Merrimelia pipeline. This pipeline was used to transport more than 98% of produced volumes for both the quarter and year ended March 31, 2015. These pipeline costs are marginally higher than trucking costs; however connecting Cuisinier oil from wellhead to tanker has increased deliverability.

RESULTS OF OPERATONS - CANADA

Canadian Operating Results	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2015	2014	% Change	**2015**	2014	% Change
Natural Gas Sales ($000s)	**23**	87	(74)	**246**	274	(10)
Production(mcf/d)	**114**	180	(37)	**164**	201	(18)
Realized commodity prices ($/mcf)	**2.23**	5.38	(59)	**4.10**	3.74	10
NGL Sales ($000s)	**-**	11	N/A	**28**	68	(59)
Production(bbl/d)	**-**	2	N/A	**1**	2	(50)
Realized commodity prices ($/bbl)	**N/A**	79.14	N/A	**70.89**	87.29	(19)
Royalties ($000s)	**1**	11	(91)	**31**	29	7
($/boe)	**0.58**	2.21	(74)	**2.98**	3.82	34
Operating expenses ($000s)	**44**	71	(38)	**233**	241	(3)
($/boe)	**25.73**	18.56	39	**22.42**	26.13	21
Operating Netback ($000s)	**(26)**	16	(263)	**10**	72	(86)
($/boe)	**(15.20)**	5.56	(373)	**0.96**	5.48	(83)

Canadian operations are comprised entirely of the Company's non-operated Oak natural gas field in British Columbia. This asset is considered non-core and therefore no significant expenditures were allocated to the Oak field in fiscal 2015, however decrease benchmark natural gas prices resulted in decreased profitability for the asset.

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

G&A Expenses and SBC ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2015	2014	% Change	**2015**	2014	% Change
Net G&A	901	1,197	(25)	3,407	3,822	(11)
Capitalized G&A	83	130	(36)	373	421	(11)
Total G&A	984	1,327	(26)	3,780	4,243	(11)
$/boe	20.84	31.21	(33)	22.93	24.82	(8)
Expensed share-based compensation	23	90	(74)	170	498	(66)
Capitalized share-based compensation	4	28	(86)	40	152	(74)
Total share-based compensation	27	118	(77)	210	650	(68)

The 11% decrease in total cash G&A expenditures for the year reflects management's ongoing efforts to reduce discretionary spending and the elimination of certain one-time severance expenditures. These targeted efforts to reduce G&A costs are fully reflected in the current quarter's total cash G&A which has decreased by 26% compared to Q4 2014.

Bengal accounts for its share-based compensation plan using the fair value method. Under this method, each grant results in three instalments. The fair value of the first instalment is charged to profit or loss immediately. The remaining two instalments are charged to profit or loss over their respective vesting period of one and two years respectively. For options that vest one-third each year after the first year anniversary, the fair value of the options are charged to profit and loss over the three year vesting period. Stock options granted under the plan can be exercised on a cashless basis, whereby the employee receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the employee so elects.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2015	2014	% Change	**2015**	2014	% Change
PNG – Australia	**1,161**	1,253	(7)	**4,623**	4,434	4
PNG – Canada	**150**	21	614	**413**	97	115
Subtotal	**1,311**	1,274	3	**5,036**	4,531	9
Rig - Canada	**-**	-	-	**330**	-	-
Total	**1,311**	1,274	3	**5,162**	4,531	15
$/boe – PNG Australia	**25.51**	29.47	(13)	**28.05**	28.07	-
$/boe – PNG Canada	**87.72**	7.42	1,082	**53.86**	7.47	594
$/boe – Total PNG	**27.76**	28.09	(1)	**29.46**	26.50	11

Depletion per boe in Australia has remained consistent with the prior year and quarter ended March 31, 2015 as significant increases to proved plus probable reserve volumes were complemented by a corresponding increase to expected future development costs.

The drilling rig is fully impaired; therefore there is no depreciation charge.

Impairment

Impairment ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2015	2014	% Change	**2015**	2014	% Change
Total	**-**	2,111	N/A	**4,762**	3,101	54

As at December 31, 2014, the Company recognized the significant decrease in market crude prices and the excess of drilling rigs in the local and international market as an indicator of impairment for its drilling rig. The Company evaluated current drilling activity and rig sale activity both locally in Australia and internationally to determine that under current market conditions its drilling rig should be fully impaired at December 31, 2014.

During June 2014, the Koki-1 exploration well was drilled to a vertical depth of 2,573 meters and did not encounter the targeted Murta DC70 reservoir. Its secondary target indicated minor, non-commercial oil shows and it was agreed to suspend and abandon this well. Based on these results, the Company has recorded an impairment charge of $0.8 million equal to its share of drilling costs associated with this well.

During December 2014, Bengal drilled the Wicho East exploration well primarily targeting the deeper Jurassic Hutton horizon. This well failed to intersect a commercial hydrocarbon accumulation and was plugged and abandoned during the quarter. Based on these results, the Company has recorded an impairment charge of $0.8 million equal to its share of drilling costs associated with this well.

Finance Income/Expenses

Finance Expenses ($000s)		Three Months Ended March 31			Twelve Months Ended March 31	
	2015	2014	% Change	**2015**	2014	% Change
Interest income	**5**	5	-	18	74	(76)
Accretion expense on decommissioning liabilities	**(4)**	(19)	(79)	**(15)**	(8)	88
Accretion expense on notes payable	**-**	(51)	(100)	**(507)**	(216)	135
Change in fair value of VARs	**7**	64	(89)	**58**	123	(53)
Fee on bank guarantee	**(55)**	(72)	(41)	**(55)**	(72)	(41)
Letter of credit charges	**(32)**	-	N/A	**(32)**	-	N/A
Interest and prepayment penalties on notes payable & credit facility	**(342)**	(219)	56	**(1,212)**	(756)	60
Finance expenses	**(421)**	(292)	44	**(1,745)**	(855)	104

The Performance Security Guarantee fee is paid to Export Development Canada and ICICI Bank of India for security guarantee for onshore India work programs, to be cancelled on completion or relinquishment. The increased fee is a result of the budgeted 2015 work program.

Interest expenses are comprised of $0.7 million of interest and prepayment penalties on notes payable, $0.3 million of interest on the Company's credit facility, and $0.2 million related to non-cash accretion of debt instruments. The Company paid a 3% penalty on the remaining $7.5 million outstanding in addition to interest otherwise accrued on its July 2014 $8.0 million notes payable.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2015	2014	% Change	**2015**	2014	% Change
Geological and geophysical	320	708	(55)	**1,276**	3,137	(59)
Drilling	1,732	389	345	**8,458**	2,601	225
Rig	-	371	(100)	**-**	371	(100)
Completions	358	376	(5)	**3,729**	3,574	4
Cuisinier working interest purchase	-	204	(100)	**-**	6,964	(100)
Total oil & gas expenditures	2,410	2,048	18	**13,463**	16,647	(19)
Office	-	-	-	**-**	-	-
Total expenditures	2,410	2,048	18	**13,463**	16,647	(19)
Exploration & evaluation expenditures	267	672	(60)	**3,189**	1,963	63
Development & production expenditures	2,143	1,005	113	**10,247**	14,313	(28)
Property, plant & equipment	-	371	(100)	**-**	371	(100)
Total net expenditures	2,410	2,048	18	**13,463**	16,647	(19)

During the year, the Company drilled, completed and tied in all wells from its 2014 phase 1 drilling program, as well as completed drilling and most completion work associated with the 2014 phase 2 drilling program. These successful well costs, as well as the drilling costs associated with two unsuccessful exploration wells (Koki, Wicho East) and one successful exploration well (Nubba-1) accounts for all drilling and completion costs incurred during the quarter and year ended March 31, 2015.

Geological and geophysical costs relate primarily to the ongoing review and interpretation of seismic studies on the ATP 752 exploration permit supporting exploration drilling in Barta and Wompi.

NOTES PAYABLE & CREDIT FACILITY

On January 24, 2014, $1.75 million of convertible notes set to expire on January 25, 2014 were extended to January 24, 2015. These notes were redeemed on January 21, 2015 for a redemption price of $2.0 million including principal and accrued and unpaid interest. Approximately $0.8 million of the aggregate was paid in cash, and certain holders of the remaining $0.9 million of aggregate principal received the redemption price through the issuance of common shares of the Company at a price of $0.28 per common share in lieu of cash.

In October 5, 2014, the Company repaid $500,000 of outstanding principal of its $8.0 million notes issued July 5, 2013. In November 2014, the Company redeemed the remaining principal of $7,500,000 for an early redemption price equal to $1.03 per $1.00 (booked as interest expense) of outstanding principal amount plus all accrued and unpaid interest thereon.

In October 2014, Bengal closed its US $25 million secured credit facility with Westpac Institutional Bank and placed an initial draw on November 12, 2014 of US $14.0 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% to 3.5% depending on certain reserve forecast parameters. Current interest rate is 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. Calculation dates commence December 31, 2015 and occur every six months thereafter until June 30, 2017 with a nominal reduction of $6.25 million to the facility limit at each calculation date based on the Company's existing reserve profile. The facility limit at March 31, 2015 is US $25 million.

The credit facility's covenants extend only to the Company's ability to secure its debt as a percentage of reserve forecasts to be evaluated at each calculation date. There are no financial covenants associated with this credit facility.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. At June 13, 2015, there were 68,177,796 common shares issued and outstanding, 3,495,000 employee stock options outstanding, 703,125 warrants outstanding and 546,875 VARs outstanding.

Trading History	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2015	2014	% Change	**2015**	2014	% Change
High	**$ 0.32**	$ 0.62	(48)	**$ 0.76**	0.79	(4)
Low	**$ 0.18**	$ 0.40	(55)	**$ 0.18**	$ 0.40	(55)
Close	**$ 0.19**	$ 0.48	(60)	**$ 0.19**	$ 0.48	(60)
Volume (000s)	**2,759**	6,621	(58)	**11,611**	10,323	12
Shares outstanding (000s)	**68,178**	64,667	5	**68,178**	64,667	5
Weighted average shares outstanding (000s)						
Basic	**67,364**	64,446	5	**65,349**	63,134	4
Diluted	**67,364**	64,446	5	**65,349**	63,209	3

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2015 the Company had $5.2 million of working capital, including cash and short-term deposits of $1.7 million and restricted cash of $0.1 million, compared to working capital of $3.1 million, including cash and short term deposits of $6.0 million and restricted cash of $0.1 million at March 31, 2014.

In October 2014, Bengal closed its US $25 million secured credit facility with Westpac Institutional Bank and placed an initial draw on November 12, 2014 of US $14.0 million. The facility is secured by and available for 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% to 3.5% depending on certain reserve forecast parameters. In the year ended March 31, 2015, $0.3 million has been charged to financing expenses related to interest on the credit facility.

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. Calculation dates commence December 31, 2015 and occur every six months thereafter until June 30, 2017 with a nominal reduction of $6.25 million to the facility limit at each calculation date based on the Company's existing reserve profile.

The credit facility's covenants extend only to the Company's ability to secure its debt as a percentage of reserve forecasts to be evaluated at each calculation date.

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. The Company's existing cash and cash equivalents and operating cash flows supplemented by funds undrawn funds on its US $25 million credit facility available for use in the Cuisinier field are expected to be sufficient to meet all of its working capital requirements for at least the next twelve months and its commitments under its capital program (see Commitments below).

The Company expects cash generation to increase throughout the coming year as production from Cuisinier ramps up, although predicting future events, some of which are beyond the Company's control, carries uncertainty.

COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities in its Indian permits 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 venture partners to proceed with activities (e.g. onshore Australia ATP 752 Cuisinier). 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 will vary from budget.

Country and Permit	**Work Program**	**Obligation Period Ending**	**Estimated Expenditure (net) (millions CAD$)**(1)
Onshore India – CY-ONN-2005/1	3 wells	Currently under Force Majeure(2)	$ 5.3

(1) Translated at March 31, 2015 at an exchange rate of US $1.0000 = CAD $1.2642
(2) If the Company did not participate in the drilling of 3 wells, costs of $5.2 million would be impaired and the Company's interest in the permit would decline.

GUARANTEES – INDIA PERMITS

($000s) CAD	**Year Ended March 31, 2015**	Year ended March 31, 2014
CY-OSN-2005/1 – Onshore India	**914**	1,570
CY-OSN-2009/1 – Offshore India	**-**	166
Total Guarantees	**914**	$ 1,736

These performance guarantees are based on a percentage of the capital commitments shown in the table above and are not reflected in the statement of financial position as they are secured by Export

Development Canada. These guarantees are cancelled when the Company completes the work program commitment required for the applicable exploration period.

OTHER

At March 31, 2015, 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	$ 595	$ 263	$ 332	$ -	$ –
Decommissioning obligations	1,454	-	56	116	1,282
Total contractual obligations	$ 2,049	$ 263	$ 388	$ 116	$ 1,282

CONTINGENCIES

Effective March 1, 2015 ATP 934 has been granted for a period of 12 years comprised of 3, 4 year terms. In the first four year work program Bengal is committed to capital spending of approximately $22.6 million dollars (net $11.3 million) dedicated to acquisition of new 2D and 3D seismic as well as drilling of up to 8 new wells. Bengal has made application to the Queensland Government for a smaller work program to reflect geographical conditions that may preclude surface access to parts of ATP 934.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)
Onshore Australia – ATP 934P	Awaiting Ministerial approval before granting of ATP	4 years after grant of ATP	$ 11.3

RELATED PARTY TRANSACTIONS

On July 5, 2013, the Company issued $8.0 million of 10% non-convertible notes with warrants or value appreciation rights. Members of the Board of Directors of the Company subscribed for approximately 44% of the principal amount of the notes issued pursuant to the private placement. In October 2014, the Company repaid $500,000 of outstanding principal of notes issued July 5, 2013 (“Notes”). In November 2014, the Company redeemed the remaining Notes for a redemption price equal to $1.03 per $1.00 of outstanding principal amount plus all accrued and unpaid interest thereon.

On January 24, 2014 the Company extended its $1.75 million notes payable to January 23, 2015. Members of the Board of Directors of the Company held 100% of this facility.

On January 21, 2015, the Company repaid the $1.75 million notes payable, together with accrued interest. Two directors were issued 3,485,714 shares of the Company valued at $0.28 per share in lieu of a cash settlement of $976,000.

SUBSEQUENT EVENTS

Effective April 1, 2015 Bengal acquired an additional 30% working interest in ATP 934 from one of its Joint Venture partners for a total acquisition price of $0.1 million. This acquisition is subject to ministerial approval. The remaining joint venture partner, effective June 19, 2015 exercised its option to purchase 8.6% of this interest; therefore Bengal’s current working interest is 71.4%.

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED ANNUAL FINANCIAL INFORMATION

($000s except per share data and prices)

Year Ended March 31	2015	2014	2013
Total production volumes (boepd)	**480**	468	170
Natural gas prices ($/mcf)	**4.10**	3.74	2.61
Oil and liquids prices ($/boe)	**93.35**	123.13	112.01
Total production revenue	**15,669**	19,822	5,885
Net income (loss)	**(3,172)**	150	(1,799)
Per share – basic and diluted	**(0.05)**	0.00	(0.03)
Cash from operations	**6,921**	7,591	(703)
Funds from operations (1)	**4,589**	8,183	1,099
Per share – basic and diluted	**0.07**	0.13	0.02
Balance drawn on credit facility	**16,982**	-	-
Notes payable – long term	**-**	6,085	-
Total assets	**65,679**	62,425	49.143
Working capital (deficiency)(2)	**5,221**	3,104	(1,647)

(1) See "Non-IFRS Measurements" on page 6 of this MD&A.
(2) Calculated as current assets minus current liabilities.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)

	Mar 31 2015	Dec. 31 2014	Sep. 30 2014	Jun. 30 2014	Mar 31 2014	Dec. 31 2013	Sep. 30 2013	Jun. 30 2013
Petroleum and natural gas sales	**$ 3,378**	$3,944	$4,458	$3,889	$ 5,272	$ 5,516	$ 5,312	$ 3,722
Cash from (used in) operations	**1,031**	1,144	2,232	2,219	2,106	2,170	2,066	1,249
Funds from (used in) operations(1)	**939**	1,318	1,459	926	2,218	2,862	2,063	1,732
Per share Basic and diluted	**0.01**	0.02	0.02	0.01	0.03	0.04	0.03	0.03
Net (loss) income	**$(1,052)**	$(1,293)	$(98)	$(729)	$(1,804)	$ 573	$ 545	$ 836
Per share Basic and diluted	**(0.02)**	(0.02)	0.00	$(0.01)	(0.03)	0.01	0.01	0.01
Capital expenditures	**2,410**	$4,489	$2,909	$3,655	$ 2,048	$ 6,462	$ 2,702	5,435
Working capital (deficiency)	**5,221**	4,931	(1,705)	(88)	3,104	3,590	7,737	(279)
Total assets	**65,679**	66,229	60,385	60,216	62,425	61,353	62,361	54,556
Shares outstanding Basic and diluted	**68,178**	64,692	64,692	64,692	64,446	64,315	64,315	61,611
Operations								
Average daily production								
Natural gas (mcfd)	**114**	181	169	194	180	184	200	240
Oil and NGLs (bbls/d)	**506**	548	429	329	474	465	485	316
Combined (boepd)	**525**	578	457	361	504	496	518	356
Netback ($/boe)	**45.86**	$36.79	$65.05	$73.15	$ 74.28	$ 83.13	$ 72.51	$ 79.82

(1) See "Non-IFRS Measurements" on page 7 of this MD&A. The bottom line of this table pops out showing a hefty decline in netback from the December quarter perhaps we should explain this in the text.

Oil volumes increased through the first three quarters of fiscal 2015 as wells from the Cuisinier 2014 phase 1 development program came on stream. By the fourth quarter of 2015, natural declines decreased production volumes compared to the prior quarter.

Netbacks and associated operating results decreased in the third and fourth quarter of fiscal 2015 due to a significant decrease in benchmark crude oil prices.

FINANCIAL INSTRUMENTS

Financial instruments comprise cash, restricted cash and short term deposits, accounts receivable and accounts payable and accrued liabilities and debt. The fair values of these financial instruments approximate their carrying amounts due to their short-term maturities.

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 by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not use derivative instruments at this time.

Financial assets and liabilities are classified as either financial assets or liabilities at fair value through profit and loss ("FVTPL"), loans and receivables, held to maturity investments, available for sale financial assets, or other liabilities, as appropriate. Financial assets and liabilities are recognized initially at fair value.

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets and liabilities are measured at fair value and changes in fair value are recognized in profit or loss. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive loss until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability classified as FVTPL are expensed immediately. For a financial asset or financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to or deducted from the fair value on initial recognition and amortized through profit or loss income over the term of the financial instrument.

(i) Non-derivative financial instruments

Cash and cash equivalents, restricted cash as well as accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities, notes payable and the credit facility are classified as other financial liabilities, which are measured at amortized cost.

(ii) Derivative financial instruments

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

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

Fair value

The fair value of financial instruments that are actively traded in organized financial markets is determined by reference to quoted market bid prices at the valuation date. For financial instruments that have no active market, fair value is determined using valuation techniques including the use of recent arm's length market transactions, reference to the current market value of equivalent financial instruments and discounted cash flow analysis.

Share capital

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

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, 2015 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. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies

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

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.

i. 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.

ii. 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 and PP&E assets required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

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 the assets and liabilities.

i) 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.

ii) 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.

iii) Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. 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 is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period which the change occurs.

iv) 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.

v) 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: 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 AND PRONOUNCEMENTS

The following new accounting policies were adopted as at April 1, 2014, both of which were applied retrospectively:

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, “Levies” which was adopted by the Company on April 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no impact on the Company's consolidated financial statements.

IAS 32, “Financial Instruments: Presentation”, which clarifies the requirements for offsetting financial assets and liabilities. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability. There was no impact on the Company’s consolidated financial statements on adoption of this standard.

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.

Accounting for acquisitions of interests in joint operations

In May 2014, the IASB issued amendments to IFRS 11 “Joint Arrangements” to clarify that the acquirer of an interest in a joint operation in which the activity constitutes a business is required to apply all of the principles of business combinations accounting in IFRS 3 “Business Combinations”. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Company in the event that it increases or decreases its ownership share in an existing joint operation or invests in a new joint operation.

Sale or contribution of assets between an investor and its associate or joint venture

In September 2014, the IASB issued amendments to address an inconsistency between the requirements in IFRS 10 “Consolidated Financial Statements” and those in IAS 28 “Investments in Associates and Joint Ventures” regarding the sale or contribution of assets between an investor and its associate or joint venture. The amendment clarified that a full gain or loss is recognized when a transaction involves a business. A partial gain or loss is recognized when a transaction involves assets that do not constitute a business. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Company in the event that it has transactions with associates or joint ventures.

Disclosure initiative

In December 2014, the IASB issued narrow-focus amendments to IAS 1 “Presentation of Financial Statements” to clarify existing requirements relating to materiality, order of notes, subtotals, accounting policies and disaggregation. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the Company's disclosure.

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 was to be effective for fiscal years beginning on or after January 1, 2017, with earlier application permitted. On May 19, 2015, the IASB published the expected exposure draft aimed at deferring the effective date of IFRS 15 "Revenue from Contracts with Customers" to 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.

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 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;*
- *Projections of market prices and costs;*

- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *Expectations that cash generation to increase throughout the coming year*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Completion of the four development wells is anticipated to run from mid-July through early August 2014, with the wells expected to be tied in through September 2014.*
- *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;*
- *Expectations that cash flow from the new production volumes to begin in the fourth quarter of calendar 2014;*
- *Expectation of the drilling of a exploration at ATP 752 well in calendar Q3 2014;*
- *Obtaining Ministerial Grant of the tenement on ATP 934P in Australia and commencement of exploration activities;*
- *Expectation that the selection of three drilling locations in India expected to begin drilling in 2015*
- *That Beach Energy will perform the work agreed to under the Farm-out and that further drilling activities on ATP 732P will occur in the second half of calendar 2014;*
- *That the wells drilled on ATP 752P will be completed and tied-in and that these wells will commence production and that production from all wells will continue as expected.*

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, that 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.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

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

Management is also responsible for establishing and maintaining appropriate systems of internal control over the company's financial reporting. The internal control system was designed to provide reasonable assurance to management regarding the preparation and presentation of the consolidated financial statements. Management tested and evaluated the effectiveness of its disclosure controls and procedures and internal controls over financial reporting as at March 31, 2015. During this evaluation Management identified weaknesses due to the limited number of finance and accounting personnel at the Corporation dealing with complex and non-routine accounting transactions that may arise and due to a lack of segregation of duties and as a result the controls are not considered effective. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable but not absolute assurance that financial information is accurate and complete.

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

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

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

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

To the Shareholders of Bengal Energy Ltd.

We have audited the accompanying consolidated financial statements of Bengal Energy Ltd., which comprise the consolidated statements of financial position as at March 31, 2015 and March 31, 2014, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Bengal Energy Ltd. as at March 31, 2015 and March 31, 2014, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
June 18, 2015
Calgary, Canada

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2015	2014
ASSETS			
Current assets:			
Cash and cash equivalents	5	$ 1,749	$ 5,984
Restricted cash		140	140
Accounts receivable		3,109	3,821
Prepaid expenses and deposits		348	490
Fair value of financial instruments	16	2,164	-
		7,510	10,435
Non-current assets:			
Exploration and evaluation assets	6	28,245	26,821
Petroleum and natural gas properties	7	27,122	21,669
Property, plant and equipment	8	-	3,500
Fair value of financial instruments	16	2,802	-
		58,169	51,990
Total assets		$ 65,679	$ 62,425
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		2,289	$ 4,174
Current portion of notes payable	10	-	3,158
		2,289	7,332
Non-current liabilities:			
Decommissioning liability	12	1,454	358
Credit facility	11	16,982	-
Notes payable	10	-	6,085
Other long-term liabilities	10	3	61
		18,439	6,504
Shareholders' equity:			
Share capital	13	94,151	93,151
Contributed surplus		7,341	7,141
Warrants	10	167	167
Accumulated other comprehensive income		(130)	1,536
Deficit		(56,578)	(53,406)
		44,951	48,589
Total liabilities and shareholders' equity		$ 65,679	$ 62,425

Commitments and contingencies (note 19)

Subsequent events (note 22)

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Chayan Chakrabarty

Director
Chayan Chakrabart

Director
James B. Howe

BENGAL ENERGY LTD.

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

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes	2015	2014
Income			
Petroleum and natural gas revenue		**$15,669**	$19,822
Royalties		**(1,057)**	(1,334)
		14,612	18,488
Realized gain on financial instruments		**891**	-
Unrealized gain on financial instruments		**4,962**	-
		20,465	-
Operating expenses			
General and administrative		**3,407**	3,822
Transaction costs		**-**	261
Operating and transportation		**6,247**	5,290
Depletion and depreciation	**7,8**	**5,162**	4,531
Pre-licensing & impairment	**6,8**	**4,762**	3,101
Share-based compensation		**170**	498
		19,748	17,503
Operating income		**717**	985
Other (expenses)			
Other		**(334)**	-
Finance (expenses) income	**15**	**(1,745)**	(855)
Foreign (loss) exchange		**(1,810)**	(35)
		(3,889)	(890)
Net (loss) income		**(3,172)**	150
Exchange differences on translation of foreign operations		**(1,666)**	(45)
Total comprehensive income (loss) for the year		**(4,838)**	105
(Loss) earnings per share	**13**		
- Basic & diluted		**(0.05)**	0.00
Weighted average number of shares outstanding (000s)	**13**		
- Basic & diluted		**65,349**	63,134

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

	Shares outstanding	Share capital	Warrants	Contributed surplus	Equity component of convertible debentures	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2013	52,110,177	$ 86,246	$ –	$ 6,466	$ 25	$ 1,581	$ (53,556)	$ 40,762
Net income for the year	-	-	-	-	-	-	150	150
Comprehensive (loss) for the year	-	-	-	-	-	(45)	-	(45)
Issuance of common shares	12,556,905	7,327	-	-	-	-	-	7,327
Share issue costs	-	(422)	-	-	-	-	-	(422)
Share-based compensation – expensed	-	-	-	498	-	-	-	498
Share-based compensation – capitalized	-	-	-	152	-	-	-	152
Warrants	-	-	167	25	(25)	-	-	167
Balance at March 31, 2014	64,667,082	$ 93,151	$ 167	$ 7,141	$ -	$ 1,536	$ (53,406)	$ 48,589
Balance at April 1, 2014	**64,667,082**	**$ 93,151**	**$ 167**	**$ 7,141**	**$ -**	**$ 1,536**	**$ (53,406)**	**$ 48,589**
Net loss for the year	**-**	**-**	**-**	**-**	**-**	**-**	**(3,172)**	**(3,172)**
Comprehensive (loss) for the year	**-**	**-**	**-**	**-**	**-**	**(1,666)**	**-**	**(1,666)**
Issuance of common shares	**3,510,714**	**1,000**	**-**	**(10)**	**-**	**-**	**-**	**990**
Share-based compensation – expensed	**-**	**-**	**-**	**170**	**-**	**-**	**-**	**170**
Share-based compensation – capitalized	**-**	**-**	**-**	**40**	**-**	**-**	**-**	**40**
Balance at March 31, 2015	**68,177,796**	**94,151**	**167**	**7,341**	**-**	**(130)**	**(56,578)**	**44,951**

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the years ended March 31	Notes	2015	2014
Operating activities			
Net (loss) income for the year		$ (3,172)	$ 150
Non-cash items:			
Depletion and depreciation		5,162	4,531
Pre-licensing & impairment		4,762	3,101
Accretion on decommissioning liability		15	(8)
Accretion on notes payable and credit facility /change in fair value of VARs		551	93
Settlement of decommissioning liability		(19)	-
Share-based compensation		170	498
Deferred income tax recovery		-	(55)
Unrealized gain on financial instruments		(4,962)	-
Unrealized foreign exchange loss (gain)		2,082	(127)
		4,589	8,183
Change in non-cash working capital	18	2,332	(592)
Net cash from (used in) operating activities		6,921	7,591
Investing activities			
Exploration and evaluation expenditures	6	(3,189)	(1,963)
Petroleum and natural gas properties	7	(10,274)	(14,313)
Property, plant and equipment	8	-	(371)
Changes in non-cash working capital	18	(2,642)	(808)
Net cash used in investing activities		(16,105)	(17,455)
Financing activities			
Proceeds from issuance of shares, net of issuance costs	13	14	5,405
Proceeds from issuance of credit facility, net of issuance costs	11	14,520	7,743
Repayment of notes	10	(8,774)	(250)
Changes in non-cash working capital	18	(673)	(5)
Net cash from financing activities		5,087	12,893
Impact of foreign exchange on cash and cash equivalents		(138)	341
Net increase (decrease) in cash equivalents		(4,235)	3,370
Cash and cash equivalents, beginning of year		5,984	2,614
Cash and cash equivalents, end of year		$ 1,749	$ 5,984

See accompanying notes to consolidated financial statements.

BENGAL ENERGY LTD.

Notes to Consolidated Financial Statements (the "financial statements")

Years ended March 31, 2015 and 2014
(Tabular amounts are stated in thousands of Canadian dollars except share and per share amounts)

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 consolidated financial statements (the "financial statements") of the Company as at March 31, 2015 and 2014 and for the years ended March 31, 2015 and 2014 are comprised of the Company and its wholly owned subsidiaries Bengal Energy International Inc., which are incorporated in Canada and Bengal Energy Australia (Pty) Ltd., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. which are incorporated in 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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on June 18, 2015.

b) Basis of measurement

These consolidated financial statements have been prepared on a historical cost basis.

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 India subsidiary is US dollars and the functional currency of the Australian subsidiary is Australian dollars.

3. SIGNIFICANT ACCOUNTING POLICIES

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

(a) Basis of consolidation:

The consolidated interim financial statements incorporate the financial statements of the Company and its wholly and majority owned subsidiaries, Bengal Energy Australia (Pty) Ltd., Bengal Energy International Inc., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. respectively.

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

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

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

(b) Cash and cash equivalents

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

(c) Provisions

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

Decommissioning and restoration liabilities:

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

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

(d) Oil and natural gas exploration and evaluation expenditures

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

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

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

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

(e) Petroleum and natural gas properties

Carrying value

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as petroleum and natural gas properties in the specific asset to which they relate. Petroleum and natural gas properties are stated at cost less accumulated depreciation and depletion and accumulated impairment losses. The initial cost of a petroleum and natural gas property is comprised of its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given up to acquire the asset.

Subsequent costs

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

Depletion and depreciation

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

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

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

(f) Property and equipment – drilling rig

Recognition and measurement

Initial costs related to the acquisition or construction of property and equipment are capitalized and accumulated by rig or a component thereof.

Subsequent to initial recognition, items of property and equipment are measured at cost less accumulated depreciation and accumulated impairment losses. When significant parts of an item of property and equipment have different useful lives, they are accounted for as separate items (major components).

Subsequent costs are included in the related asset's carrying amount or recognized as a separate asset, as appropriate, only when is it probable that future economic benefits associated with the item will flow to the group and the cost of the item can be measured reliably. All other repairs and maintenance are recorded in profit and loss.

Gains and losses on disposal of an item of property and equipment are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized in profit and loss.

(g) Impairment

E&E and Petroleum and Natural Gas Properties

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and when they are reclassified to Development and Production ("D&P") assets. For the purpose of impairment testing, E&E assets are grouped by concession or field with other E&E assets belonging to the same concession or field. The impairment loss will be calculated as the excess of the carrying value over recoverable amount of the E&E impairment grouping and any resulting impairment loss is recognized in profit or loss. Recoverable amount is determined as the higher of the value in use or fair value less costs to sell.

At the end of each reporting period, the Company reviews the petroleum and natural gas properties for circumstances that indicate that the assets may be impaired. Assets are grouped together into cash generating units ("CGU"s) for the purpose of impairment testing, which is the lowest level at which there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. A CGUs recoverable amount is the higher of its fair value less selling costs and its value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of future cash flows expected to be derived from the production of proved and probable reserves.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less cost to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down. Consideration is given to acquisition metrics or recent transactions completed on similar assets to those contained with the relevant CGU.

When the recoverable amount is less than the carrying amount, the asset or CGU is impaired. For impairment losses identified based on a CGU, the loss is allocated on a pro rata basis to the assets within the CGU(s). The impairment loss is recognized as an expense in profit or loss.

At the end of each subsequent reporting period these impairments are assessed for indicators of reversal. Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss have been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

Property and Equipment

At the end of each reporting period, the Company reviews property and equipment for circumstances that indicate that the assets may be impaired. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount, which is the higher of its fair value less selling costs and its value in use.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of an asset in an arm's length transaction between knowledgeable and willing parties. Consideration is given to recent transactions related to similar assets.

When the recoverable amount is less than the carrying amount, the asset is impaired and the resulting impairment loss is recognized as an expense in profit or loss.

At the end of each subsequent reporting period these impairments are assessed for indicators of reversal. Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss have been recognized for the asset in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

Financial assets

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

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

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

All impairment losses are recognized in profit or loss.

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

(h) Financial instruments

Financial assets and liabilities are classified as either financial assets or liabilities at fair value through profit and loss ("FVTPL"), loans and receivables, held to maturity investments, available for sale financial assets, or other liabilities, as appropriate. Financial assets and liabilities are recognized initially at fair value.

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets and liabilities are measured at fair value and changes in fair value are recognized in profit or loss. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive loss until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability classified as FVTPL are expensed immediately. For a financial asset or financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to or deducted from the fair value on initial recognition and amortized through profit or loss income over the term of the financial instrument.

(i) Non-derivative financial instruments

Cash and cash equivalents, restricted cash as well as accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities, notes payable and the credit facility are classified as other financial liabilities, which are measured at amortized cost.

(ii) Derivative financial instruments

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

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

Fair value

The fair value of financial instruments that are actively traded in organized financial markets is determined by reference to quoted market bid prices at the valuation date. For financial instruments that have no active market, fair value is determined using valuation techniques including the use of recent arm’s length market transactions, reference to the current market value of equivalent financial instruments and discounted cash flow analysis.

Share capital

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

(i) Foreign currency translation:

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

(j) Share-based compensation:

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

(k) Revenue recognition:

Revenue from the sale of natural gas, natural gas liquids and crude oil is recognized when the significant risks and rewards of ownership is transferred, which is when title passes to the customer in accordance with the terms of the sales contract. This generally occurs when the product is physically transferred into a pipe, truck or other delivery mechanism.

(l) Per share amounts:

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

(m) Income taxes:

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

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

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

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

(n) Finance income and expenses:

Finance income consists of interest earned on term deposits. Finance expenses include fees on Performance Security Guarantees issued by Export Development Canada, bank fees on Bank Guarantees issued to the Government of India, letter of credit charges, interest on notes payable and the credit facility, accretion on notes payable and change in fair value of VARS, and accretion of the discount on decommissioning obligations.

(o) Determination of fair value:

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

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

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

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

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

Financial instruments comprise cash, cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, credit facility, notes payable and derivatives.

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

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

i. **Cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities**

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

ii. **Credit facility**

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

iii. **Notes payable**

The fair value of notes payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2015 and 2014, the fair value of these balances approximated their carrying value due to their short term to maturity.

iv. **Derivatives**

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

(p) Adoption of new accounting policies

The following new accounting policies were adopted as at April 1, 2014, both of which were applied retrospectively:

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies" which was adopted by the Company on April 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no impact on the Company's consolidated financial statements.

IAS 32, "Financial Instruments: Presentation", which clarifies the requirements for offsetting financial assets and liabilities. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability. There was no impact on the Company's consolidated financial statements on adoption of this standard.

(q) 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.

Accounting for acquisitions of interests in joint operations

In May 2014, the IASB issued amendments to IFRS 11 "Joint Arrangements" to clarify that the acquirer of an interest in a joint operation in which the activity constitutes a business is required to apply all of the principles of business combinations accounting in IFRS 3 "Business Combinations". Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Company in the event that it increases or decreases its ownership share in an existing joint operation or invests in a new joint operation.

Sale or contribution of assets between an investor and its associate or joint venture

In September 2014, the IASB issued amendments to address an inconsistency between the requirements in IFRS 10 "Consolidated Financial Statements" and those in IAS 28 "Investments in Associates and Joint Ventures" regarding the sale or contribution of assets between an investor and its associate or joint venture. The amendment clarified that a full gain or loss is recognized when a transaction involves a business. A partial gain or loss is recognized when a transaction involves assets that do not constitute a business. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Company in the event that it has transactions with associates or joint ventures.

Disclosure initiative

In December 2014, the IASB issued narrow-focus amendments to IAS 1 "Presentation of Financial Statements" to clarify existing requirements relating to materiality, order of notes, subtotals, accounting policies and disaggregation. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the Company's disclosure.

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 was to be effective for fiscal years beginning on or after January 1, 2017, with earlier application permitted. On May 19, 2015, the IASB published the expected exposure draft aimed at deferring the effective date of IFRS 15 "Revenue from Contracts with Customers" to 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.

4. MANAGEMENT JUDGMENTS AND ESTIMATES

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

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.

i) 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.

ii) 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 and PP&E assets required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

iii) 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.

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 the assets and liabilities.

i) 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.

ii) 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.

iii) Current and deferred income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period which the change occurs.

The deferred tax asset is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

iv) 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.

v) 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.

5. CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash on hand and in banks and investments with an original maturity date of 90 days or less. Cash and cash equivalents at the end of the reporting period as shown in the statement financial position are comprised of:

As at **($000s)**	**March 31, 2015**	March 31, 2014
Cash and bank balances	**$ 1,743**	$ 5,164
Short-term deposits	**6**	820
	$ 1,749	$ 5,984

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

($000s)		Exploration and Evaluation Expenditures
Balance at April 1, 2013	$	**26,416**
Additions		1,963
Capitalized share-based compensation		59
E&E impairment loss		(1,367)
Exchange adjustments		(250)
Balance at March 31, 2014	**$**	**26,821**
Additions		3,189
Capitalized share-based compensation		10
E&E impairment loss		(1,592)
Exchange adjustments		(183)
Balance at March 31, 2015	**$**	**28,245**

Exploration and evaluation assets consist of the Company's exploration projects in Australia and India 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.

During June 2014, the Koki-1 exploration well was drilled to a vertical depth of 2,573 meters and did not encounter the targeted Murta DC70 reservoir. Its secondary target indicated minor, non-commercial oil shows and it was agreed to suspend and abandon this well. Based on these results, the Company has recorded an impairment charge of $0.8 million equal to its share of drilling costs associated with this well.

During December 2014, Bengal drilled the Wicho East exploration well primarily targeting the deeper Jurassic Hutton horizon. This well failed to intersect a commercial hydrocarbon accumulation and was plugged and abandoned during the quarter. Based on these results, the Company has recorded an impairment charge of $0.8 million equal to its share of drilling costs associated with this well.

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

	Exploration and Evaluation Assets		
($000s)	**Australia**	**India**	**Total**
ATP 732P – Tookoonooka **– Note 1**	$ 20,126	$ -	$ 20,126
ATP 752P	-	-	-
CY-ONN-2005/1 – onshore	-	5,272	5,272
Other – **Note 2**	1,423	-	1,423
March 31, 2014 ($000)	**$ 21,549**	**$ 5,272**	**$ 26,821**
	Exploration and Evaluation Assets		
	Australia	**India**	**Total**
ATP 732P – Tookoonooka **– Note 1**	$ 18,825	$ -	$ 18,825
ATP 752P	1,044	-	1,044
CY-ONN-2005/1 – onshore	-	6,771	6,771
Other – **Note 2**	1,605	-	1,605
March 31, 2015 ($000)	**$ 21,474**	**$ 6,771**	**$ 28,245**

Note 1: The Company entered into a farm-out agreement that requires a 2-well drilling program of which one remains to be drilled at March 31, 2015. Once the final well is drilled, the joint venture partner will earn a 50% interest in this permit and the Company will record a gain or loss on this 50% disposition.
Note 2: Other includes ATP 934P, capitalized G&A and stock-based compensation and foreign exchange effects on assets denominated in foreign currencies.

7. PETROLEUM AND NATURAL GAS PROPERTIES

$000s	Petroleum and Natural Gas Properties	Corporate Assets	Total
Cost:			
Balance at April 1, 2013	**$ 13,810**	**$ 427**	**$ 14,237**
Additions	7,448	(99)	7,349
Acquisitions	6,964	-	6,964
Capitalized share-based compensation	93	-	93
Change in decommissioning obligation	120	-	120
Exchange adjustments	(31)	(10)	(41)
Balance at March 31, 2014	**28,404**	**318**	**28,722**
Additions	10,274	-	10,274
Non-cash additions	53	-	53
Capitalized share-based compensation	30	-	30
Change in decommissioning obligation	1,118	-	1,118
Exchange adjustments	(1,178)	24	(1,154)
Balance at March 31, 2015	**38,701**	**342**	**39,043**

	Petroleum and Natural Gas Properties $000s	Corporate Assets $ 000s	Total $000s
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2013	**$ 2,447**	**$ 160**	**$ 2,607**
Depletion and depreciation charge	4,455	76	4,531
Exchange adjustments	(83)	(2)	(85)
Balance at March 31, 2014	**6,819**	**234**	**7,053**
Depletion and depreciation charge	4,800	32	4,832
Exchange adjustments	59	(23)	36
Balance at March 31, 2015	**11,678**	**243**	**11,921**
Net carrying value			
At March 31, 2014	$ 21,585	$ 84	$ 21,669
At March 31, 2015	$ 27,023	$ 99	$ 27,122

The calculation of depletion for the year ended March 31, 2015 included $123.8 million and $nil million for estimated future development costs associated with proved and probable reserves in Australia and Canada respectively (March 31, 2014 - $83.5 million and $0.5 million).

8. PROPERTY, PLANT AND EQUIPMENT

($000s)	Rig Equipment
Balance at March 31, 2013	$ 4,756
Additions	374
Capitalized share-based compensation	-
Balance at March 31, 2014	**$ 5,130**
Additions	-
Balance at March 31, 2015	**5,130**
Accumulated depletion, depreciation and impairment losses:	
Balance at March 31, 2013	$ 73
Impairment	**1,557**
Balance at March 31, 2014	**$ 1,630**
Depreciation and impairment	**3,500**
Balance at March 31, 2015	**$ 5,130**
Net book value	
Balance at March 31, 2014	**$ 3,500**
Balance at March 31, 2015	**$ -**

On April 5, 2012 the Company purchased an Ideco H-44 drilling rig. The purchase price of the Rig was US $1.75 million. Additional costs were incurred to transport the rig from its point of purchase, prepare the rig and acquire certain ancillary equipment required for drilling operations. This rig was used to drill, case and test the Caracal-1 well on permit ATP 732.

As at December 31, 2014, the Company recognized the significant decrease in market crude prices and the excess of drilling rigs in the local and international market as an indicator of impairment for its drilling rig. The Company evaluated current drilling activity and rig sale activity both locally in Australia and internationally to determine that under current market conditions its drilling rig should be fully impaired at December 31, 2014.

The recoverable amount of nil was determined using fair value less cost to sell based on level 3 fair value inputs as described by IFRS 13, specifically the frequency of asset sales in the Australian and international markets, internal estimates of fair value of component parts as well as transpirations costs. There were no benchmark transactions identified through management's review of sales markets, based on low transaction volumes and high volume of equipment available for sale. This, along with management's internal estimates determined that the expected proceeds from disposition are less than the expected cost to transport.

9. INCOME TAXES

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

Years Ended March 31 ($000s)	2015	2014
(Loss) income before taxes	**(3,172)**	95
Statutory tax rate	**25%**	25%
Expected income tax expense (recovery)	**(793)**	(24)
Foreign exchange	**(614)**	83
Stock-based compensation	**51**	(121)
Effect of change in tax rate & other	**(394)**	(300)
Other	**194**	(11)
Changes in unrecognized tax asset	**1,556**	428
Income tax recovery	**$ -**	$ 55

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

As of March 31 ($000s)	2015	2014
Non-capital losses	**$ 27,373**	$ 26,395
Net capital losses	**5,890**	6,033
P&NG properties	**8,288**	5,033
Share issue costs	**742**	720
Decommissioning obligations	**99**	358
	$ 42,392	$ 38,539

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

As of March 31 ($000s)	2015	2014
Property, plant & equipment	**14,515**	12,737
Fair value of financial instruments	**1,490**	331
Foreign exchange	**(416)**	-
Decommissioning obligations	**(400)**	-
Non-capital losses	**(15,189)**	(13,068)
	$ -	$ -

At March 31, 2015, the Company had approximately $29.5 million and $50.6 million of non-capital losses in Canada and Australia respectively (2014- $23.7 million and $46.5 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2016 to 2035. The Australian non-capital losses have no term to expiry. The Company's ongoing drilling activities continue to generate deferred assets related to Petroleum Resource Rent Tax ("PRRT") in its Australia subsidiary, which has not been recognized.

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At March 31, 2015, the Company has no deferred tax liabilities in respect of these temporary differences.

10. NOTES PAYABLE

Non-Convertible Notes – Issued July 5, 2013 ($000s)	Total	Debt Component	Other long-term liability	Warrants
Gross proceeds	8,000	7,593	178	229
Total cash fees	(257)	(256)	6	(7)
	7,743	7,337	184	222
Accretion on debt/change in fair value of VARs	33	156	(123)	-
Deferred tax impact	(55)	-	-	(55)
Balance at March 31, 2014	7,721	7,493	61	167
Accretion on debt/change in fair value of VARs	**449**	**507**	**(58)**	**-**
Repayment	**(8,000)**	**(8,000)**	**-**	**-**
Balance at March 31, 2015	**170**	**-**	**3**	**167**

In October 5, 2014, the Company repaid $0.5 million of outstanding principal of notes issued July 5, 2013. In November 2014, the Company redeemed the remaining principal of $7.5 million for an early redemption price equal to $1.03 per $1.00 (booked as interest expense) of outstanding principal amount plus all accrued and unpaid interest thereon. Interest expense recorded during the year on the July 5, 2013 notes totaled $0.7 million, including the early redemption fee.

In conjunction with the $8.0 million notes issued July 5, 2013, 546,845 VARs and 703,125 warrants remain outstanding. Each whole warrant entitles the holder thereof, until July 5, 2016, to acquire one common share in the capital of the Company at a purchase price equal to $0.75 per share. Each whole VAR entitles the holder thereof, until July 5, 2016, to exercise the VAR and thereby receive a cash payment equal to the difference between the market price of one common share on the exercise date and $0.75. The warrants and initial VAR valuation are valued based on the following key assumptions: a term of 3 years, volatility of 73% and a price of $0.75/share.

On January 21, 2015 the Company redeemed its January 25, 2013 notes payable for a redemption price of $2.0 million including principal and accrued and unpaid interest. Approximately $0.8 million of the aggregate was paid in cash, and certain holders of the remaining $0.9 million of aggregate principal received the redemption price through the issuance of common shares of the Company at a price of $0.28 per common share in lieu of cash. Interest expense recorded during the year on the January 25, 2013 notes totaled $0.1 million.

11. CREDIT FACILITIY

Facility Agreement – Issued November 12, 2014 ($000s)	
Gross proceeds	**15,364**
Total cash fees	**(844)**
	14,520
Unrealized foreign exchange loss	**2,307**
	16,827
Accretion	**155**
Balance at March 31, 2015	**16,982**

In October 2014, Bengal closed its US $25 million secured credit facility with Westpac Institutional Bank and placed an initial draw on November 12, 2014 of US $14.0 million. The facility is secured by and available to 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% to 3.5% depending on certain reserve forecast parameters. During the year $0.3 million has been charged to financing expenses related to interest on the credit facility.

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. Calculation dates commence December 31, 2015 and occur every six months thereafter until June 30, 2017 with a nominal reduction of $6.25 million to the facility limit at each calculation date based on the Company's existing reserve profile. The facility limit at March 31, 2015 is US $25 million.

The credit facility's covenants extend only to the Company's ability to secure its debt as a percentage of reserve forecasts to be evaluated at each calculation date. There are no financial covenants associated with this credit facility.

12. 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)	March 31, 2015	March 31, 2014
Decommissioning liabilities, beginning of year	$ 358	$ 320
Revision	901	(82)
Decommissioning expenditures	(19)	-
Additions	217	120
Accretion	15	8
Exchange adjustments	(18)	(8)
Decommissioning liabilities, end of year	**$ 1,454**	**$ 358**

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation adjusted undiscounted amount of cash flows required to settle its decommissioning and restoration costs at March 31, 2015 is approximately $1,990,000 (March 31, 2014 – $567,000) which will be incurred between 2015 and 2038. An inflation factor ranging between 1.3% and 2.5% (2014 – 1.0% and 2.5%) and a risk free discount rate ranging between 2.3% and 4.1% (2014 – 1.5% and 4.1%) have been applied to the decommissioning liability at March 31, 2015.

Revisions are entirely related to a change in cost estimates.

13. 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:

($000s)	Number of Shares	Amount
Balance at March 31, 2013	52,110,177	**$ 86,246**
Shares issued for cash	9,500,666	**5,700**
Issued on conversion of convertible debentures	2,678,572	**1,500**
Issued on exercise of stock options for cash	351,667	**127**
Issued on cashless exercise of stock options	26,000	**-**
Share issue costs	-	**(422)**
Balance at March 31, 2014	64,667,082	**93,151**
Issued on conversion of debt	3,485,714	**976**
Issued on exercise of stock options for cash	25,000	**14**
Issued from contributed surplus on exercise of stock options	-	**10**
At March 31, 2015	**68,177,796**	**94,151**

On January 23, 2015 two insiders were issued 3,485,714 common share of the Company valued at $0.28 per share in lieu of a cash settlement of $976,000 on repayment of notes payable.

(c) Share-based compensation – stock options:

The Company has a share option plan for directors, officers, employees and consultants of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of three to five years and vest one-third immediately and one-third on each of the next two anniversary dates. The exercise price of each option equals the market price of the Company's common shares on the date of the grant. Effective with the option grant on December 21, 2012, vesting occurs one third after the first year and one third on each of the two subsequent anniversaries.

Bengal accounts for its share-based compensation plan using the fair value method. Under this method, each grant results in three instalments. The fair value of the first instalment is charged to profit or loss immediately. The remaining two instalments are charged to profit or loss over their respective vesting period of one and two years respectively. For options that vest one-third each year after the first year anniversary, the fair value of the options are charged to profit and loss over the three year vesting period. Stock options granted under the plan can be exercised on a cashless basis, whereby the employee receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the employee so elects.

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2013	**4,196,665**	**$ 0.98**
Granted	1,195,000	0.62
Expired	(846,664)	1.23
Forfeited	(270,001)	0.71
Exercised	(401,667)	0.36
Outstanding at March 31, 2014	**3,873,333**	**$ 0.89**
Granted	-	-
Forfeited	(116,667)	0.62
Expired	(216,666)	0.99
Exercised	(25,000)	0.58

Outstanding at March 31, 2015	**3,515,000**	**$**	**0.89**
Exercisable at March 31, 2015	**2,938,341**	**$**	**0.95**

	Options Outstanding			**Options Exercisable**	
Option Price (1)	**Number Outstanding**	**Exercise Price (2)**	**Remaining Life (3)**	**Number Exercisable**	**Exercise Price (2)**
$0.47 - $0.65	1,855,000	$0.60	3.08	1,278,341	$0.60
$0.66 - $1.25	1,080,000	$1.17	1.84	1,080,000	$1.17
$1.26 - $1.32	580,000	$1.32	1.25	580,000	$1.32
Total	**3,515,000**	**$0.89**	**2.40**	**2,938,341**	**$0.95**

(1) Range of option exercise prices
(2) Weighted average exercise price of options
(3) Weighted average remaining contractual life of options in years

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

For the Year Ended	**March 31, 2015**	**March 31, 2014**
Assumptions:		
Risk free interest rate (%)	-	2.0%
Expected life (years)	-	5 yr
Expected volatility (%)(1)	-	73%
Estimated forfeiture rate (%)	-	7.1%
Weighted average fair value of options granted	-	$0.37
Weighted average share price on date of grant	-	$0.62

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

The fair value of stock options granted during the year ended March 31, 2015 was $nil (2014 - $417,000). No options were granted during the year ended March 31, 2015.

(d) Per share amounts:

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

For the Year Ended ($000s)	**March 31, 2015**	**March 31, 2014**
Income (loss) for the year	**(3,172)**	150
Weighted average number of common shares (basic)	65,349	63,134
Weighted average number of common shares (diluted)	65,349	63,209
Basic and diluted income (loss) per share	**(0.05)**	0.00

At March 31, 2015, there were 3,515,000 (March 31, 2014 – 2,683,000) options considered anti-dilutive. In addition, there were 703,125 warrants and 546,875 value appreciation rights considered anti-dilutive.

14. COMPENSATION OF KEY MANAGEMENT PERSONNEL

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

Year ended March 31 ($000s)	2015	2014
Salaries & employee benefits	**$ 840**	$ 930
Share-based compensation[(1)]	**80**	208
General & administrative expenses	**$ 920**	$ 1,138

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

Salaries and benefits for the year ended March 31, 2015 include a non-recurring retirement payment to former employees of $nil million (2014 - $0.2 million).

15. FINANCE INCOME/EXPENSES

Year ended March 31 ($000s)	2015	2014
Interest income	**$ 18**	$ 74
Accretion on decommissioning obligations	**(15)**	8
Performance Security Guarantee fee [(1)]	**(55)**	(72)
Letter of credit charges	**(32)**	-
Interest on notes payable and credit facility	**(1,212)**	(771)
Accretion on notes payable and change in fair value of VARs	**(449)**	(94)
Finance income (expenses)	**$ (1,745)**	$ (855)

(1) Fees paid to Export Development Canada and ICICI Bank for security guarantees for onshore and offshore India work programs.

16. FINANCIAL RISK MANAGEMENT

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

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

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at March 31, 2015, Bengal's receivables consisted of $2.6 million (March 31, 2014 - $3.5 million) from joint venture partners and $0.5 million (March 31, 2014 - $0.3 million) of other trade receivables of which $0.5 million has been subsequently collected.

Production from the Canadian operations is marketed by the operator. Bengal established a payment schedule with the operator of the property and considers the entire amount to be receivable.

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.

At March 31, 2015, the Company had no accounts considered past due (past due is considered greater than 90 days outstanding). Bengal believes these receivables will be collected.

The carrying amount of accounts receivable and cash and cash equivalents and the carrying value of its financial instruments represent the Company's maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at March 31, 2015 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended March 31, 2015. Exposure to the carrying value of its financial instruments relate to the Company's commodity based derivatives held by Westpac Banking Corporation, which carries a Standard & Poors credit rating of AA-. Management considers the credit risk of these instruments to be adequately mitigated by the credit stating 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 and credit facility and amounted to $19.3 million at March 31, 2015 (March 31, 2014 - $13.4 million).

At March 31, 2015 the Company had $5.2 million of working capital, including cash and short-term deposits of $1.7 million and restricted cash of $0.1 million.

During the year, Bengal finalized a US $25.0 million secured credit facility drawing US $14.0 million in November and subsequently redeeming its $8.0 million notes payable. Proceeds from this facility are restricted for use within the Cuisinier production licence. As at March 31, 2017, US$ 11.0 million remains available and undrawn on this facility.

During the year ended March 31, 2015, there has been a significant decrease in market crude prices. The Company's oil sales are benchmarked on dated Brent prices. The Company incurs most of its expenditures in Australian dollars which have depreciated significantly relative to the US dollar, in which the Company generates revenues. To mitigate net impact of declining crude prices, , the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near near-term cash flow upside. The Company has also entered into derivative commodity contracts, to reduce the impacts 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.

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

Credit facility (US$000s)	
Fiscal year 2017	7,750
Fiscal year 2018	6,250
	14,000

(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 March 31, 2015 ($000s)	CAD	AUD	USD
Cash and short-term deposits	$ 130	$ 1,094	$ 525
Restricted cash	140	-	-
Accounts receivable	70	3,039	-
Accounts payable and accrued liabilities	(250)	(2,008)	(31)
Notes payable and other long-term liability	(3)		
Credit facility	-	-	(16,982)
Fair value of financial instruments	-	-	4,966
	$ 87	**$ 2,125**	**$ (11,522)**

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 Daily Brent reference price, which trades at a premium to WTI.

At March 31, 2015, the following derivative contracts were outstanding and recorded at estimated fair value:

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US$/bbl)	Fixed Price (US$/bbl)
Apr 1, 2015 – May 31, 2017	Oil - Swap	130,252	N/A	80.00
Apr 1, 2015 – May 31, 2017	Oil – Put option	106,569	80.00	-

($000s)	**Oil - swap**	**Oil – put**	**Total**
Current fair value of financial instruments	1,161	1,003	**2,164**
Non-current fair value of financial instruments	1,359	1,443	**2,802**
Total	**2,520**	**2,446**	**4,966**

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US $237,000 decrease in the fair value of financial instruments at March 31, 2015 while a $US1 decrease would result in an increase of approximately US$237,000 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 material interest rate risk on its cash and cash equivalents at March 31, 2015 as the funds are not invested in an interest bearing instrument. The Company is exposed to interest rate risk on its credit facility. 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 March 31, 2015.

For the year ended March 31, 2015, a 1% increase in LIBOR would increase interest expense on the credit facility by $66.

17. CAPITAL MANAGEMENT

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility which will allow it to execute on its capital investment program, provide creditor and market confidence and to sustain future development of the business.

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

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

The Company has drawn US $14 million from its US $25 million available credit facility and typically structures its debt position below 2.0 times projected 12 month net operating cash flows. The Company is within these parameters at March 31, 2015.

18. CHANGES IN NON-CASH WORKING CAPITAL

Year ended March 31 ($000s)		2015		2014
Accounts receivable	$	712	$	(271)
Prepaid expenses and deposits		142		(380)
Accounts payable and accrued liabilities		(1,885)		(449)
Impact of foreign exchange		48		(305)
Total	$	(983)	$	(1,405)
Relating to:				
Operating	$	2,332	$	(592)
Financing		(673)		(808)
Investing		(2,642)		(5)
Total	$	(983)	$	(1,405)

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

Year ended March 31 ($000s)		2015		2014
Cash interest paid	**$**	**1,201**	$	708
Cash interest received	**$**	**13**	$	74

19. COMMITMENTS AND CONTINGENCIES

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 venture 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.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore India – CY-ONN-2005/1	Three wells	Currently under Force Majeure(2)	$5.3

(1) Translated at March 31, 2015 at an exchange rate of US $1.00 = CAD $1.2642

(2) If the Company did not participate in the drilling of three wells, costs of $5.3 million would be impaired and the Company's interest in the permit would decline.

At March 31, 2015 the Company had the following lease commitment for office space in Canada.

($000s)					
April 2015 to March 2017	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Office lease	**$ 595**	**263**	**332**	**-**	**-**

Effective April 1, 2012 the Company entered into a head lease in Calgary, Canada for a term of five years.

Contingencies:

Effective March 1, 2015 ATP 934 has been granted for a period of 12 years comprised of 3, 4 year terms. In the first four year work program Bengal is committed to capital spending of approximately $22.6 million dollars (net $11.3 million) dedicated to acquisition of new 2D and 3D seismic as well as drilling of up to 8 new wells. Bengal has made application to the Queensland Government for a smaller work program to reflect geographical conditions that may preclude surface access to parts of ATP 934.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)
Onshore Australia – ATP 934P	Awaiting Ministerial approval before granting of ATP	4 years after grant of ATP	$ 11.3

20. SUPPLEMENTAL DISCLOSURE

Bengal's consolidated statement of income (loss) and comprehensive income (loss) is prepared primarily by nature of expense. All salaries for the Company are included in general and administrative expenses and for the year ended March 31, 2015 amount to $1.4 million (March 31, 2014 - $1.4 million).

21. RELATED PARTY TRANSACTIONS

On July 5, 2013, the Company issued $8.0 million of 10% non-convertible notes with warrants or value appreciation rights. Members of the Board of Directors of the Company subscribed for approximately 44% of the principal amount of the notes issued pursuant to the private placement. In October 2014, the Company repaid $500,000 of outstanding principal of notes issued July 5, 2013 ("Notes"). In November 2014, the Company redeemed the Notes for a redemption price equal to $1.03 per $1.00 of outstanding principal amount plus all accrued and unpaid interest thereon.

On January 24, 2014 the Company extended its $1.75 million notes payable to January 23, 2015. Members of the Board of Directors of the Company held 100% of this facility, which was fully redeemed on January 21, 2015. Two directors were issued 3,485,714 shares of the Company valued at $0.28 per share in lieu of a cash settlement of $976,000.

22. SUBSEQUENT EVENTS

Effective April 1, 2015 Bengal acquired an additional 30% working interest in ATP 934 from one of its Joint Venture partners for a total acquisition price of $0.1 million. This acquisition is subject to ministerial approval. The remaining joint venture partner, effective June 19, 2015 exercised its option to purchase 8.6% of this interest; therefore Bengal's current working interest is 71.4%.

23. SEGMENTED INFORMATION

As at March 31, 2015, 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 not 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 year ended March 31, 2015 ($000s)				
	Australia	**Canada**	**India**	**Total**
Revenue	15,395	274	-	15,669
Interest revenue	17	1	-	18
Interest expense	332	880	-	1,212
Depletion and depreciation	4,623	413	-	5,036
Net (earnings) loss	4,354	(6,964)	(562)	(3,172)
Exploration and evaluation expenditures	3,084	-	105	3,189
Petroleum and natural gas property expenditures	10,274	-	-	10,274
Property, plant & equipment expenditures	-	-	-	-
Impairment losses (recovery)	1,592	3,296	-	4,888
March 31, 2015 ($000s)				
Petroleum and natural gas properties				
Cost	34,407	4,637	-	39,044
Impairment loss	(796)	(437)	-	(1,233)
Accumulated depletion, depreciation and accretion	(6,586)	(4,103)	-	(10,689)
Net book value	27,025	97	-	27,122
Exploration and evaluation assets	32,653	-	7,963	40,616
Accumulated impairment losses	(11,179)	-	(1,192)	(12,371)
Net book value	21,474	-	6,771	28,245
Property, plant & equipment	-	5,130	-	5,130
Accumulated depletion, depreciation and accretion	-	(403)	-	(403)
Impairment		(4,727)		(4,727)
Net book value	-	-	-	-

For the year ended March 31, 2014 ($000s)				
	Australia	**Canada**	**India**	**Total**
Revenue	19,480	342	-	19,822
Interest revenue	73	1	-	74
Interest expense	-	777	-	777
Depletion and depreciation	4,435	96	-	4,531
Net (earnings) loss	6,802	(4,976)	(1,676)	150
Exploration and evaluation expenditures	767	-	1,196	1,963
Petroleum and natural gas property expenditures	14,313	-	-	14,313
Property, plant & equipment expenditures	-	371	-	371
Impairment losses (recovery)	-	1,928	1,173	3,101
March 31, 2014 ($000s)				
Petroleum and natural gas properties				
Cost	24,105	4,617	-	28,722
Impairment loss	-	-	-	-
Accumulated depletion, depreciation and accretion	(3,034)	(4,019)	-	(7,053)
Net book value	21,071	598	-	21,669
Exploration and evaluation assets	30,619	-	6,993	37,612
Accumulated impairment losses	(9,621)	-	(1,170)	(10,791)
Net book value	20,998		5,823	26,821
Property, plant & equipment	-	5,127	-	5,127
Accumulated depletion, depreciation and accretion	-	(70)	-	(70)
Impairment	-	(1,557)	-	(1,557)
Net book value	-	3,500		3,500

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
West Pac Bank • Brisbane, Australia
Commonwealth Bank • Brisbane, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Valiant Trust Corporation • Calgary, 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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