Appraisal and Exploration Drilling with High-Impact Upside

Bengal
ENERGY LTD.

Annual Report | **2013**

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MESSAGE TO SHAREHOLDERS

The 2013 fiscal year was an active and successful period for Bengal, evidenced by the continued growth in our production, reserves and revenue, as well as the achievement of several important milestones which further advance our progress and set the stage for expanded development.

In Australia, Bengal continued to focus efforts and capital appraising the Cuisinier oil pool located on the Barta block in the Cooper Basin, in which we hold a 25% non-operated working interest. Drilling success continued in Cuisinier through calendar 2012 and into the first half of calendar 2013, with a 100% success rate achieved on all 13 wells drilled to date. This area is an important driver for the company, offering near-term production volumes and revenue, as well as extensive future drilling locations to support growth longer term.

Net production volumes averaged 325 barrels of oil equivalent per day (‘boepd’) for the quarter ending March 31, 2013, an increase of over 215% compared to the same period in 2012, and an increase of 60% over the 203 boe/d produced in the preceding quarter. The vast majority of those volumes are from oil production in Cuisinier. It is anticipated that production volumes will continue to grow through the balance of calendar 2013, as the five wells drilled in the current year Cuisinier campaign are tied in. Longer term, production growth is supported by two achievements that occurred subsequent to the end of the fiscal year. The first was Bengal’s receipt of final approval of the required lease for the Cuisinier oil pool, which occurred in April 2013, which permits all current and future Cuisinier wells to produce for up to 21 years. Secondly, the Cuisinier to Cook liquids pipeline was commissioned in June 2013 and enables production to be delivered to sales points through a pipeline, rather than trucking, which expands the area’s productive capacity and facilitates more stable production volumes. These position Bengal very well for future development and production growth in Cuisinier.

A key driver of value for oil and gas companies stems from their booked reserves. As we continue to drill, appraise and develop our assets, we anticipate seeing additional activity reflected in positive revisions to our reserve report. Since our year end falls on March 31, our reserve evaluation is performed as at that date, which means that none of the 2013 Cuisinier drilling which occurred subsequent to March 31 will be reflected in the independent evaluation of proved plus probable reserves performed as at that date. However, we do anticipate undertaking another reserve evaluation in the fall which will capture that activity. Despite this timing difference, Bengal’s year-end 2013 corporate proved plus probable (2P) reserves increased 167% relative to fiscal year end 2012. Based on 2P reserves additions, we successfully replaced approximately 18 times our annual production for the year ending March 31, 2013.

In addition to production and reserves growth, we also realized growth in our revenue, and importantly, operating netbacks. Netback is an important measure because it helps demonstrate how much operating cash flow can be generated from each barrel of oil produced. One of the features that differentiates Bengal from many of our Canadian peers is our realized oil price. Not only is our oil production in Australia a light, sweet crude which commands the highest price, but oil prices in Australia are benchmarked off of Brent pricing, rather than the North American standard of West Texas Intermediate (WTI). During our fiscal year ended March 31, 2013, the Brent reference price traded at a premium to WTI of nearly US$18, which contributed to attractive netbacks on our Australian oil production, including netbacks of just under CAD$70/bbl in the fourth quarter. The favourable royalty regime in Australia also contributes to higher netbacks, and Bengal’s royalties are expected to decline on a per boe basis from 2013 levels during the 2014 fiscal year.

At Bengal's Tookoonooka property in Australia, the Company has a 100% working interest in the block, which offers a portfolio of multi-zone exploration prospects. During the 2013 fiscal year, the first exploration well in the Tookoonooka drilling campaign, Caracal-1, was drilled and resulted in a new light oil discovery. Subsequent to the end of the fiscal year, we signed a Binding Letter of Intent to form a strategic joint venture for the exploration and development of the Tookoonooka Permit with Australia-based Beach Energy Ltd., a leader in Cooper Basin oil and gas exploration, development and production. Under the terms of the agreement, Beach will fund the drilling of two wells and the acquisition of an additional 300 km^2 of 3D seismic up to a maximum of AUD$11.5 million, in return for a 50% interest in the property. This is a significant development for Bengal, as it will enable us to accelerate exploration and appraisal work in Tookoonooka while preserving balance sheet strength and benefiting from the experience and expertise of a premium player in the Cooper Basin.

Bengal also has assets on two blocks in India's Cauvery Basin, which represent longer term, future opportunity. Bengal has a 30% working interest in 946 km^2 (233,000 acres) onshore at CY-ONN-2005/1, and a 100% interest in 1,362 km^2 (340,000 acres) offshore at CY-OSN-2009/1. Onshore, Bengal and our joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, completed the acquisition of a 3D seismic program of approximately 600 km^2 during the 2013 fiscal year and various prospects have been identified. Plans call for the drilling of three wells on the CY-ONN-2005/1 onshore block to commence before the end of calendar 2013.

Offshore in the Cauvery basin, evaluation work continues with several play types and prospects emerging following interpretation of the various 2D and 3D seismic data sets. To accelerate timing of the drilling of an offshore exploration well, additional seismic data may be acquired in late 2013 or early 2014. Recent competitor activity in the local area and on offsetting blocks provides encouragement for Bengal to consider accelerating our activity. As such, Bengal is seeking a joint venture partner to continue the exploration and appraisal of this asset. We will continue to closely monitor developments occurring in offsetting blocks for additional activity, which could include competitors drilling up to three wells by mid calendar 2014, which would provide data and information that facilitates Bengal's understanding of the asset.

With the completion of a $3.5 million financing of convertible and non-convertible notes in January 2013, the completion of a $5.7 million equity financing in April 2013, the recent farmout of the Tookoonooka block, and our growing production and resultant cash flow stream, we believe Bengal is well positioned to move forward with our near term exploration plans and work program commitments. Bengal's sizeable land positions in both Australia and India provide our shareholders with exposure to oil and gas opportunities that span the spectrum: pure exploration through to production, booked reserves and cash flow. Not only are Bengal's assets in politically, fiscally and economically stable jurisdications, Australia and India both operate under British Common Law. This means that although Bengal is an interational oil and gas company, many of the risks that are inherent with so many other junior international operators have been minimized in Bengal.

Bengal's growth and evolution is being led by a team of seasoned international exploration professionals, governed by a top tier board of directors offering a vast array of relevant skills and experience. Going forward, we are excited by our large portfolio of lower-risk and high-impact drilling opportunities that have historically produced very attractive netbacks. We will continue development and appraisal drilling at Cuisinier which is expected to drive near-term and increasingly positive operating income and set the stage for expanded development. Our recent exploration success at Tookoonooka has enhanced our confidence about the prospectivity of this area and our joint venture with Beach has created further momentum. We believe that drilling activity on our onshore permit in India in late 2013 could lead to additional value creation in 2014 and beyond. While keeping a sharp focus on furthering development of our existing asset base, we will also continue to evaluate potential accretive transactions that may arise in and around those core areas.

We are pleased to have this opportunity to report on our progress to our shareholders, joint venture partners and employees, and we thank you once again for your continued support of our vision.

Sincerely,

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, 2013 and 2012.

FISCAL 2013 HGHLIGHTS

During the period the Company experienced the following significant highlights and events:

- **Cuisinier Drilling 2012** – The Company drilled four oil producers in calendar 2012, resulting in a cumulative drilling success rate of eight for eight in the non-operated Cuisinier Field in the Cooper Basin of Australia.
- **Petroleum License -** On April 8, 2013 the final approval of Petroleum Lease 303 ("PL303") for the Cuisinier oil pool was granted. This license allows all current and future Cuisinier wells to produce for up to 21 years.
- **Cuisinier Drilling Campaign 2013** – On March 20, 2013, the Company commenced its calendar 2013 Cuisinier drilling program comprising five development and appraisal wells and one contingent well. This program is designed to optimize pool productivity and to further define ultimate pool size, with each well targeting the Murta Formation. As of June 14, 2013, all five wells have been drilled with all being successful and continuing Bengal's 100% success rate in its Cuisinier drilling campaign. The most recent Cuisinier well makes it the 13^{th} successful well of 13 drilled to date.
- **The Cuisinier to Cook liquids pipeline** was commissioned in June 2013 and production from all eight Cuisinier wells is flowing through the pipeline at a rate of 350-375 bpd (barrels of oil per day) net to Bengal. The Operator indicated that further optimization of the system may be available which could potentially add incremental barrels.
- **Tookoonooka Drilling** – The Company's first exploration well in the Tookoonooka drilling campaign, Caracal-1, resulted in a new oil discovery. This discovery established light oil on a new and unexplored trend on the large 654,335 acre permit. Seismic mapping has defined a large structure, with the Caracal closure alone estimated to cover an area of 5.5 $miles^2$.
- **Tookoonooka Farmout** – On May 23, 2013, the Company announced that it has signed a Binding Letter of Intent to form a joint venture for the exploration and development of the Tookoonooka Permit with Australia-based Beach Energy Ltd. Under the terms of this agreement, Beach will fund the drilling of two wells in addition to the acquisition of an additional 300 km^2 of 3D seismic with a spending cap of AUD $11.5 million. One of these wells will be a second well in the Caracal area, with the second well to be situated on the new 3D seismic.
- **Production** averaged 325 boepd in the quarter ending March 31, 2013 and is expected to increase as the wells drilled in the current year Cuisinier campaign are tied in.
- **Financial:**

  Funds flow (non-IFRS measure – see note 2 on page 6) **–** Funds flow of $1.2 million in the quarter ended March 31, 2013 compared to a deficiency of $(0.6) million in the prior year quarter.

  Revenue of $3.0 million in the quarter ended March 31, 2013 compared to $0.6 million in the prior year quarter.

  Netback– (non-IFRS measure – see note 2 on page 6) - Australian netback of $72.59/boe reflects the strength of the Brent benchmark crude oil prices and is an increase of 6% over $68.81/boe for the previous year.
- **Reserves** – Independent third party year-end reserves evaluation to March 31, 2013 have shown a 167% year-over-year corporate 2P reserves increase, driven by a 260% increase of 2P reserves at Cuisinier. Based on 2P reserves additions, the Company replaced approximately 18 times its annual production to March 31 2013. These reserve additions do not reflect the five recently drilled wells at Cuisinier. Detailed reserves disclosures will be included in Bengal's 2013 Annual Information Form to be filed on SEDAR.

MANAGEMENT'S DISCUSSION AND ANALYSIS – JUNE 14, 2013

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Bengal Energy Ltd. ("Bengal" or the "Company") should be read in conjunction with the audited Consolidated Financial Statements and accompanying notes for the years ended March 31, 2013 and 2012. Bengal's financial statements were prepared under International Financial Reporting Standards ("IFRS"). Additional information relating to the Company, including detailed reserve disclosures, is included in the Company's Annual Information Form, which is available on SEDAR at www.sedar.com. The reader should be aware that historical results are not necessarily indicative of future performance.

Bengal's activities are focused in Australia, India and Canada. Over the reporting period, revenue and expenses were generated and capital expenditures were made in Australia and Canada, and capital expenditures were made in India. The Company's activities are carried out primarily in Canadian dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

OUTLOOK

The Company entered fiscal 2014 with increasing production and cash flow, a carried work program on our Tookoonooka Permit in the Cooper Basin of Australia and a balanced portfolio of exploration and development drilling opportunities on its extensive land base in Australia and India.

The Company is able to differentiate itself from its Canadian peers in that the netback received for its Australian oil production has consistently been over $70/bbl. The Brent reference price the Company receives for its oil sales has traded at an approximate US $18 premium to WTI for the year ended March 31, 2013.

AUSTRALIA – Onshore

Authority to Prospect ("ATP") 752 Barta Block - Cuisinier

In the Barta Block on ATP 752, where Bengal owns a 25% working interest, the Company has drilled five of six appraisal wells to date as part of its 2013 drilling program. This is as a follow up to the eight successful exploration and appraisal wells previously drilled. The appraisal wells were drilled directly offsetting existing producing wells within the Cuisinier field, targeting the Cretaceous Murta member. Each of these well locations is located on 3D seismic in areas where the seismic attributes are consistent with well-developed Murta sands.

During the period August to September 2012, all four wells from the 2012 drill campaign were completed as oil wells and tested. All of these wells as well as the previously equipped Barta North 1 well were tied into the existing Cuisinier 1 facility. The Cuisinier 1 site was converted to a field satellite where all well production is produced to and metered. A pipeline from the Cuisinier 1 facility to the neighbouring and existing Cook production facility was completed, and commissioned in June 2013.

This additional infrastructure allows all fluids to be pipelined to the Cook infrastructure and is expected to increase run-times for the Cuisinier field.

On April 8, 2013, the final approval of Petroleum Lease 303 ("PL303") was granted. The Department of Natural Resources and Mines has granted PL 303 for a term of 21 years commencing on April 8, 2013 and will allow production from all current and future wells in the Cuisinier oil pool (the "Cuisinier Pool"). PL 303 is 64.4 km^2 in size.

On March 20, 2013, the Company commenced its calendar 2013 Cuisinier drilling program comprising five development and appraisal wells and one contingent well. Cuisinier 7, the first appraisal well in the 2013 drilling campaign, is located approximately 1,700 metres north of the Cuisinier 1 discovery well and was cased as a future oil producer. The targeted Murta sand came in high to prognosis with approximately 10.6 metres of DC70 sandstone developed and an estimated minimum 6.8 metres net pay. The Murta interval was cored with a total of 23.5 metres of core cut (11.34 metres recovered). As of June 14, 2013, all five wells have been drilled with all being successful and continuing Bengal's 100% success rate in its Cuisinier drilling campaign

In December of 2012 the Operator completed the acquisition of approximately 220 km^2 of 3D seismic immediately north of Cuisinier. This Cuisinier North 3D is intended to evaluate additional Murta formation targets as well as deeper Jurassic Birkhead and Hutton formations. The Birkhead and Hutton produce at the Cook field, which is situated 5.9 kilometres to the south east of the Cuisinier field. The Cook Field has produced over 2.5 million barrels to date.

ATP 732 Tookoonooka Block

The acquisition of approximately 422 line kilometres of 2D and 50 km^2 of 3D seismic data at ATP 732 (Tookoonooka Block) was completed early in 2012 with the detailed geological and geophysical interpretation completed mid-year 2012.

From the seismic interpretation, drill location selection and drilling location preparation were progressed along with the acquisition of regulatory and environmental approvals from the Queensland and Australian Governments.

All drill locations were chosen based on their multi-zone potential with as many as three or four prospective targets per location. The primary target is oil on two locations and both gas and oil on a third location. The Cretaceous targets are Wyandra and Murta Formation sandstones. The Jurassic targets are Hutton, Birkhead and Westbourne Formation sandstones. These Cretaceous and Jurassic targets are established producers in existing fields located both southwest and northeast of the Tookoonooka block.

The main Permian aged reservoir of interest is the Toolachee Formation sandstone. Good evidence of the Permian gas potential is seen in the Wareena-1 well which tested over 11 MMcfd from the Toolachee sequence. Wareena-1 is located approximately 32 kilometres west of ATP 732.

The Company initiated exploratory drilling at Tookoonooka in calendar Q3 2012 with the drilling of Caracal 1. The Caracal 1 well was spud on October 5, 2012. Caracal 1 was drilled into a Wyandra Sandstone amplitude anomaly identified by 3D seismic on a 4-way structural closure up-dip of a hydrocarbon show at the offsetting Triodia 1. The Wyandra came in 26 metres high to prognosis and 47.4 metres high to the Triodia well. Good hydrocarbon fluorescence and gas shows were encountered in the upper part of the Wyandra, along with bleeding oil from the cored interval through in the Wyandra. Logs showed 24.9 metres gross Wyandra sand with log analysis results indicating 9.5 metres net pay with average 19.1% porosity and 59.8% water saturation.

Based on the results of oil shows in drill cuttings, gas readings, coring and logging information, Caracal 1 was cased as a potential Wyandra oil well. Subsequent perforation and production testing resulted in a total swabbed fluid recovery of 5.01 barrels of oil (52° API oil) and 6.3 barrels of completion fluid from the Wyandra Sandstone. Caracal 1 has been suspended as a future Wyandra oil producer.

In order to accelerate Caracal appraisal and to understand the deeper exploration potential of this very large block, the Company began looking for a suitable joint venture partner.

On May 23, 2013, the Company announced the signing of a Binding Letter of Intent to form a joint venture arrangement with Australia-based Beach Energy Ltd. Under the terms of this agreement, Beach will fund the drilling of two wells as well as the acquisition of an additional 300 km^2 of 3D seismic with a cap of AUD $11.5 million on costs. One of these wells will be a second well in the Caracal area, on the existing 3D with the second well to be situated on the newly acquired 3D seismic.

ATP 934 Barrolka Block

Final application for grant of the permit at ATP 934 (Barrolka Block) has been filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the Ministerial Grant of the tenement is received. The Company holds a 50% operating interest in this 361,268 acre permit.

Australia - Offshore

AC/P 47 Block

After extensive technical review internally and technical review by potential farm-in partners, the Company will not proceed with further exploration capital expenditures. The Company has begun negotiations with the National Offshore Petroleum Tenure Administrator (NOPTA) in regards to the permit tenure and effective February 2013 has lodged an application to relinquish this property.

AC/P 24 Block

Bengal has been advised by the operator of the permit at AC/P 24 that an extension request has been received for the Kingtree prospect and that a retention lease on the Katandra discovery has been received.

A multi-year work program application to commercialize this discovery has been lodged with NOPTA.

India - Onshore

CY-ONN-2005/1 Block

On Bengal's 30% working interest, 233,000 gross acre Block CY-ONN-2005/1 located in onshore Cauvery Basin, Bengal and its joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, have completed the acquisition of a 3D seismic program of approximately 600 km^2. As well, airborne magnetometry work was carried out over the permit in association with the seismic program. The seismic and airborne magnetometry work were intended to help the joint venture define drilling locations on the permit. A new field oil and gas discovery at North Kovilkalappal approximately 10 kilometres north of the permit highlights the potential in that northeast part of the permit.

Various prospects have been tabled by the joint venture partners with location selection now being finalized. Plans call for the drilling of three wells starting in Q3 2013.

India - Offshore

CY-OSN-2009/1 Block

Evaluation work is continuing on this 340,000 acre, 100%-owned and operated Block CY-OSN-2009/1 in India's offshore Cauvery basin. Interpretation of the various 2D and 3D seismic data sets has been completed with several play types and prospects emerging. This has now allowed planning to progress on a new seismic data program. The acquisition of additional seismic data in late 2013 or early 2014 is designed to accelerate the timing of the drilling of an exploration well. Recent competitor activity in the local area, including the $7.2 billion acquisition by BP of a 30% interest in a number of blocks held by Reliance and the recently announced exploration discoveries by Cairn India in nearby Sri Lankan waters provide encouragement. In addition, the offsetting block (OIL India Ltd. & ONGC) has seen the acquisition of 3D seismic over the entire permit (CYN-OSN-2009/2). Further exploration of this block is dependent upon Bengal acquiring a joint venture partner and a carried interest in this high reward but high cost prospect.

SUMMARY

With the issuance of $3.5 million in Notes in January 2013, completion of a $5.7 million equity financing in April 2013 and the recent farmout of the Tookoonooka block, the Company believes it is sufficiently capitalized to undertake its nearer-term exploration plans and fulfill near-term work program commitments but may require further external capital to fully evaluate the large acreage position the Company holds. The Company has an attractive and large portfolio of both lower-risk and high-impact drilling opportunities.

Development and appraisal drilling planned for the first half of calendar 2013 at Cuisinier on the Barta permit should drive near-term and increasingly positive operating income for the Company and set the stage for future expanded development. Recent exploration drilling success on the Tookoonooka Permit has enhanced the Company's confidence about the prospectivity on this permit and created further momentum; with a new joint venture partner, activity will resume later in 2013 on two separate areas of this large permit. Drilling activity on the Company's onshore permit in India in late 2013 is designed to potentially add value in 2014 and onward. The Company will continue to evaluate accretive production acquisition, exploration and corporate transaction opportunities, as and where they arise, within and around the Company's core areas.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended March 31			Twelve Months Ended March 31		
	2013	2012	% Change	**2013**	2012	% Change
Revenue						
Oil	**$ 2,946**	$ 547	439	**$ 5,669**	$ 3,908	45
Natural gas	**67**	59	14	**172**	310	(45)
Natural gas liquids	**-**	16	-	**44**	68	(35)
Total	**$ 3,013**	$ 622	384	**$ 5,885**	$ 4,286	37
Royalties	**271**	56	384	**526**	394	34
% of revenue	**9.0**	9.0	-	**8.9**	9.2	(3)
Operating & transportation	**694**	312	122	**1,726**	1,636	6
Netback[1]	**$ 2,048**	$ 254	706	**$ 3,633**	$ 2,256	61
Cash from (used in) operations:	**119**	486	(109)	**(703)**	(1,142)	(24)
Per share ($) (basic & diluted)	**(0.00)**	0.01	(100)	**(0.01)**	(0.02)	-
Funds from (used in) operations:[2]	**1,151**	(635)	(270)	**1,099**	(1,459)	(170)
Per share ($) (basic & diluted)	**0.02**	(0.01)	(300)	**0.02**	(0.03)	(167)
Net (loss):	**(592)**	(1,424)	(56)	**(1,799)**	(7,209)	(75)
Per share ($) (basic & diluted)	**(0.01)**	(0.03)	(67)	**(0.03)**	(0.14)	(71)
Capital expenditures	**$ 1,280**	$ 2,233	(23)	**$ 28,381**	$ 10,838	166
Volumes						
Oil (bpd)	**287**	50	474	**138**	90	53
Natural gas (mcfd)	**229**	304	(25)	**180**	254	(29)
Natural gas liquids (boepd)	**-**	2	(100)	**2**	3	(33)
Total (boepd @ 6:1)	**325**	103	216	**170**	135	26
Netback[1] ($/boe)						
Revenue	**$ 102.88**	$ 66.62	54	**$ 94.95**	$ 86.80	9
Royalties	**9.25**	6.02	54	**8.49**	7.97	7
Operating & transportation	**23.70**	33.33	(29)	**27.85**	33.12	(16)
Total	**$ 69.93**	$ 27.27	156	**$ 58.61**	$ 45.72	28

(1) 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 7.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the twelve months ended March 31, 2013 and 2012. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from January 1, 2013 through March 31, 2013. The terms "prior year's quarter" and "2012 quarter" are used throughout the MD&A for comparative purposes and refer to the period from January 1, 2012 through March 31, 2012.

The fiscal year for the Company is the twelve-month period ended March 31, 2013. The terms "fiscal 2013," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2012 through March 31, 2013. The terms "previous year," "prior year" and "fiscal 2012" are used in the MD&A for comparative purposes and refer to the period from April 1, 2011 through March 31, 2012. 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

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

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	**2013**	2012	**2013**	2012
Cash flow from (used in) operating activities	**119**	486	**(703)**	(1,142)
Abandonment expenditures	**-**	3	**-**	3
Changes in non-cash working capital	**1,032**	(1,124)	**1,802**	(320)
Funds from (used in) operations	**1,151**	(635)	**1,099**	(1,459)

RESULTS OF OPERATONS

Production

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

Production	Three Months Ended March 31			Twelve Months Ended March 31		
	2013	2012	% Change	**2013**	2012	% change
Natural gas (mcfd)	**229**	304	(25)	**180**	254	(29)
NGLs (boepd)	**-**	2	(100)	**2**	3	(33)
Oil (bbls/d)	**287**	50	474	**138**	90	53
Total (boepd)	**325**	103	216	**170**	135	26

(1) Natural gas and NGL volumes are from the Company's Oak property in Canada
(2) Oil volumes are from the Company's Cooper Basin permits in Australia

Oil production background:

- For the twelve months ended March 31, 2012: oil production was mainly from Cuisinier 1, 2 and 3 (C1, C2 and C3).
- C1 was shut in January 2012 and C2 and C3 were shut in during August and September of 2012 due to the expiry of their Extended Production Test licenses (EPT).
- Cuisinier 4, 5, 6 and Cuisinier North 1 and Barta North 1 all commenced production in late October 2012 (C4, C5, C6, CN1 and BN1).

Oil production increased to 287 bpd in the current quarter compared to 50 bpd in the prior year quarter due to commencement of production from the current year wells, partially offset by shut in of the C1, C2 and C3. On April 8, 2013, the final approval of Petroleum Lease 303 ("PL 303") was granted which will allow all current and future Cuisinier wells to produce for up to 21 years. Construction of the pipeline from the Cuisinier 1 facility to the neighbouring and existing Cook production facility has been completed and the pipeline has been commissioned.

Oil production increased to 138 bpd in the twelve months ended March 31, 2013 compared to 90 bpd in the prior year period. C1, C2 and C3 produced for most of the prior year period whereas the current year wells only commenced production in late October 2012 but at higher combined rates than C1, C2 and C3.

The decline in the Company's Oak B.C. non-operated gas production for the three and twelve months ended March 31, 2013 is due to natural reservoir declines and shut in of the wells on September 1, 2012, due to low gas prices. The wells recommenced production on December 3, 2012.

Pricing

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		
	2013	2012	% Change	**2013**	2012	% Change
Average Benchmark Prices						
AECO 30 day firm ($/mcf)	**$ 3.22**	$ 2.52	28	**$ 2.57**	$ 3.36	(24)
Dated Brent oil ($US/bbl)	**112.43**	118.44	(5)	**110.03**	113.84	(3)
Number of CAD$ for 1 AUD$	**1.05**	1.06	(1)	**1.03**	1.04	(1)
Number of CAD$ for 1 USD$	**1.00**	1.00	-	**1.00**	0.99	1
WTI oil ($US/bbl)	**95.76**	$ 102.76	(7)	**$92.22**	$ 97.94	(6)
Bengal's Realized Price ($CAD)						
Natural gas ($/mcf)	**$ 3.25**	$ 2.14	52	**$ 2.61**	$ 3.33	(22)
NGLs ($/bbl)	**-**	77.37	331	**57.37**	63.72	(10)
Oil ($/bbl)	**114.02**	121.06	(6)	**112.84**	119.18	(5)
Total ($/boe)	**102.88**	66.62	54	**$ 94.95**	$ 86.80	9

Although realized product prices for the twelve months ended March 31, 2013 decreased, the total Company realized price on a boe basis increased due to product mix differences (higher gas volumes and lower oil volumes in the prior period).

Bengal's total realized price on a boe basis for the twelve months ended March 31, 2013, increased as a result a higher proportion of oil production in the current year.

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 $5.14/bbl over Brent for the twelve months ended March 31, 2013.

Oak, British Columbia gas sales are marketed by the operator and the price received is based on the reference price at British Columbia's Station 2 plus $0.03 per mcf. This has resulted in a realized price to the Company of $2.61/mcf and $3.25/mcf over the last twelve and three months, respectively.

NGLs include condensate, pentane, butane and propane. While prices for condensate and pentane have a relatively strong correlation to oil prices, prices for butane and propane trade at varying discounts due to the market conditions of local supply and demand.

Petroleum and Natural Gas Sales

The following table outlines Bengal's production sales by category for the periods indicated below:

Petroleum and Natural Gas Sales ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2013	2012	% Change	**2013**	2012	% Change
Oil	**2,946**	547	439	**5,669**	3,908	45
Natural gas	**67**	59	14	**172**	310	(45)
NGLs	**-**	16	-	**44**	68	(35)
Total	**3,013**	622	384	**5,885**	4,286	37

(1) Natural gas and NGL sales are from the Company's Oak property in Canada

(2) Oil sales are from the Company's Cooper Basin permits in Australia

Petroleum and natural gas sales increased by $2,391,000 in the current quarter to $3,013,000 compared to $622,000 in the prior year quarter due to increased oil production volumes partially offset by lower gas production.

YTD revenues increased from the prior year period due to higher oil volumes and offset by lower gas production and prices.

Royalties

Royalties by Type ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2013	2012	% Change	**2013**	2012	% Change
Canada Crown	**(1)**	2	(150)	**2**	20	(90)
Can. gross overriding	**7**	4	75	**14**	21	(33)
Australia	**265**	50	430	**510**	353	45
Total	**271**	56	384	**526**	394	34
$/boe	**9.25**	6.02	54	**8.49**	7.99	6
% of revenue	**9.0**	9.0	-	**8.9**	9.2	(3)
Royalties by Commodity	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2013	2012	% Change	**2013**	2012	% Change
Natural gas						
$000s	**6**	2	200	**7**	26	(73)
$/mcf	**0.35**	0.09	289	**0.11**	0.28	(61)
% of revenue	**10.4**	4.1	154	**4.1**	8.4	(51)
Oil						
$000s	**268**	50	436	**510**	353	45
$/bbl	**10.25**	11.10	(8)	**10.15**	10.75	(6)
% of revenue	**9.0**	9.2	(2)	**9.0**	9.0	-
NGLs						
$000s	**(1)**	4	-	**9**	15	(40)
$/bbl	**202.56**	17.77	1040	**11.54**	13.65	(16)
% of revenue	**50.0**	23.0	117	**20.5**	21.4	(4)

Royalty payments are made by oil and natural gas producers to the owners of the mineral rights on the leases. These owners include governments (Crown) and freehold landowners as well as other third parties that may receive contractual overriding royalties.

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%.

In British Columbia, royalties are calculated based on average daily production from a well multiplied by a reference price. Bengal also pays a gross overriding royalty ("GORR") to the landholder of between 7.5% and 10% on some of its Oak gas wells.

Royalties have increased in the current quarter compared to the prior year quarter both on a total dollar and on a boe basis due to increased revenues and a larger proportion of higher royalty rate oil sales in the overall sales mix.

YTD royalties have also increased both on a total dollar and on a boe basis due to increased revenue and larger proportion of higher royalty rate oil sales in the overall sales mix, but less than for the current quarter.

Operating & Transportation Expenses

Operating Expenses ($000s)		**Three Months Ended March 31**			**Twelve Months Ended March 31**	
	2013	2012	% Change	**2013**	2012	% Change
Australia						
Operating	**92**	37	149	**516**	607	(15)
Transportation	**531**	192	177	**996**	693	44
	623	229	172	**1,512**	1,300	16
Canada – Oper. costs	**71**	83	(15)	**214**	336	(36)
Total	**694**	312	122	**1,726**	1,636	6
Australia						
Operating - $/boe	**3.56**	7.86	(55)	**10.27**	18.47	(44)
Transp. - $/boe	**20.54**	42.69	(52)	**19.83**	21.15	(6)
Canada - $/boe	**20.70**	17.18	21	**18.22**	20.27	(10)
Total ($boe)	**23.70**	33.33	(29)	**27.85**	33.12	(16)

Operating and transportation expenses increased in the current quarter compared to the prior year quarter mainly as a result of increased oil volumes. Australian operating costs on a boe basis decreased as fixed operating costs declined per boe as production volumes increased. Canadian operating costs declined due to lower gas volumes and increased slightly on a per boe basis.

YTD operating and transportation expenses increased compared to the prior year mainly as a result of increased oil volumes. Australian operating costs on a boe basis decreased as fixed operating costs declined per boe as production volumes increased. Canadian operating costs declined due to lower gas volumes.

Transportation costs in Australia are incurred to transport Bengal's oil production through pipelines from various processing facilities to the centralized Moomba facility which accepts production from throughout the Cooper Basin in Australia. The oil is then sent through a pipeline to Port Bonython, South Australia.

General and Administrative (G&A) Expenses

General and Admin. Expenses ($000s)		**Three Months Ended March 31**			**Twelve Months Ended March 31**	
	2013	2012	% Change	**2013**	2012	% Change
G&A	**1,036**	944	10	**4,043**	3,585	13
Capitalized G&A	**(120)**	-	-	**(504)**	-	-
Net G&A	**916**	944	(3)	**3,539**	3,585	(1)

For the quarter, gross G&A expenses increased $92,000 or 10% to $1,036,000 compared to $944,000 in the 2012 quarter. The increase is due to higher rents in the current quarter as the Company moved on April 1, 2012 from lower cost sub-let space to new space due to the expiry of the sub-lease, partially offset by recruiting and IFRS transition costs reflected in the prior year quarter.

YTD gross G&A has increased $458,000 or 13% from the prior YTD period. The increase is due to higher rent and increased salaries from hiring a Vice President, Engineering and Operations, a Senior Geologist and a Senior Geophysicist part way through the prior YTD period.

Beginning the second quarter fiscal 2013, the Company initiated capitalizing G&A expenses related to geological, geophysical and engineering expenses associated with exploration and development activities concurrent with the Company being operator for the first time and similar expenses associated with its newly acquired drilling rig.

Share-based Compensation (SBC)

Share-Based Compensation ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2013	2012	% Change	**2013**	2012	% Change
SBC – options	**173**	345	(50)	**687**	1,031	(33)
SBC – capitalized	**(46)**	(34)	35	**(200)**	(34)	488
Share-based compensation	**127**	311	(59)	487	997	(51)

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding increase to contributed surplus. Options expire three to five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries. 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.

Capitalized share-based compensation is based on the portion of capitalized fees/salaries to total fees/salaries paid to consultants and employees that have been granted options.

The decrease in share-based compensation, before capitalization, from $1,031,000 to $687,000 YTD and $345,000 to $173,000 in the current quarter is a result of having 2,450,000 options granted in the twelve months ended March 31, 2012 with one third vesting immediately and therefore having one third of their fair value expensed immediately, whereas for the 1,150,000 options granted in the twelve months ended March 31, 2013, the first one third vest after one year.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2013	2012	% Change	**2013**	2012	% Change
PNG – Australia	**708**	51	1288	**1,255**	280	348
PNG – Canada	**30**	42	(29)	**120**	140	(14)
Subtotal	**738**	93	694	**1,375**	420	227
Rig - Canada	**-**	-	-	**73**	-	-
Total	**738**	93	694	**1,448**	420	245
$/boe – PNG Australia	**27.38**	11.11	146	**24.98**	8.51	194
$/boe – PNG Canada	**8.75**	9.45	(7)	**10.22**	8.47	21
$/boe – Total PNG	**25.20**	9.93	154	**22.18**	8.50	161

Depletion per boe increased in Australia due to increases in petroleum and natural gas properties and future development costs associated with proved and probable reserves at March 31, 2013.

The drilling rig was not utilized in the current quarter and therefore there is no depreciation charge.

Impairment

Impairment ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2013	2012	**% Change**	**2013**	2012	% Change
	829	416	99	**81**	4,505	(98)

In the twelve months ended March 31, 2013 the Company reported an $847,000 impairment recovery against a previously impaired Australian exploration well. This was offset by $103,000 final costs billed for the Kingtree well drilled and abandoned in October 2011 and $825,000 in costs impaired pursuant to the surrender of permit AC/P 47.

In the twelve months ended March 31, 2012 the Company reported a $4,194,000 impairment loss against exploration and evaluation assets and a $311,000 impairment loss against Canadian development and production assets. The impairment against exploration and evaluation assets related to $3,194,000 of costs incurred on permit AC/P24 (which were determined to be impaired after drilling the Kingtree well in October 2011), $702,000 of final costs of the abandoned Hudson well drilled in 2008 and $298,000 of costs pertaining to the Wompi Block.

Finance Income

Finance Income ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2013	2012	**% Change**	**2013**	2012	% Change
	2	131	(99)	**167**	613	(73)

The Company is receiving interest on guaranteed investment certificates and term deposits. The decrease in interest income is primarily attributable to reduced principal amount of short-term deposits from the prior year periods.

Finance Expenses

Finance Expenses ($000s)	Three Months Ended March 31			Twelve Months Ended December 31		
	2013	2012	% Change	**2013**	2012	% Change
Accretion expense on decommissioning liabilities	**2**	1	100	**7**	5	40
Accretion expense on notes	**59**	-	100	**59**	-	100
Performance Security Guarantee fee	**16**	18	(11)	**43**	63	(32)
Interest on notes payable	**38**	-	-	**38**	-	-
Finance expenses	**115**	19	505	**147**	68	116

The Performance Security Guarantee fee is paid to Export Development Canada for security guarantee for onshore and offshore India work programs. The reduced fee is a result of the work program being partially fulfilled.

Interest on notes and accretion expense relate to the amortization of the discount on the $3.5 million convertible and non-convertible notes issued in January 2013.

Funds from (used in) Operations and Net Loss

For the three months ended March 31, 2013 funds from operations were $1,151,000 or $0.02 per basic and diluted share compared to funds used in operations of $635,000 or $0.01 per basic and diluted share in the 2012 quarter. Funds from operations were $1,099,000 or $0.02 per basic and diluted share for the year ended March 31, 2013 compared to funds used in operations of $1,462,000 or $0.03 per basic and diluted share in the prior year. The changes in non-cash working capital are removed from the IFRS measure cash flow from (used in) operations to arrive at the non-IFRS measure funds from (used in) operations (see reconciliation on page 7).

The net loss for the three months ended March 31, 2013 was $592,000 or $0.01 per basic and diluted share compared to a loss of $1,424,000 or $0.03 per basic and diluted share in the 2012 quarter. The reduced loss was due to increased production in the current quarter. The net loss for the year ended March 31, 2013 was $1,799,000 or $0.03 per basic and diluted share compared to $7,209,000 in the prior year. The prior year loss included impairment charges of $4,505,000 compared to only $80,000 in the current year.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2013	2012	% Change	**2013**	2012	% Change
Geological and geophysical	**$ 190**	$ 1,984	(90)	**$ 4,232**	7,277	(42)
Drilling	**672**	62	1,682	**15,595**	1,876	754
Drilling Rig	**23**	-	NA	**4,511**	-	NA
Completions	**395**	82	382	**4,023**	1,580	155
Total oil & gas expenditures	**1,280**	2,128	(20)	**28,362**	10,733	168
Office	**-**	105	NA	**19**	105	(82)
Total expenditures	**$ 1,280**	$ 2,233	(23)	**$ 28,381**	$ 10,838	166
Exploration & evaluation expenditures	**$ 303**	$ 2,047	(64)	**$ 16,017**	$ 10,213	61
Development & production expenditures	**954**	186	413	**7,853**	625	1,156
Property, plant and equipment	**23**	-	NA	**4,511**	-	NA
Total net expenditures	**$ 1,280**	2,233	(23)	**$ 28,381**	$ 8,605	186

In the year ended March 31, 2013, the Company incurred seismic expenditures on its onshore India permit CY-ONN-2005/1 to complete a 575 km^2 3D seismic shoot and a 75 square kilometer high resolution 3D seismic shoot and in Australia to shoot a 220 km^2 3D program to the north of the Cuisinier pool on the Barta Block permit ATP 752.

In the year ended March 31, 2013, drilling and completion expenditures were incurred to drill 5 Cuisinier appraisal wells and complete, equip and tie-in four of these wells on the Company's ATP 752 permit. Costs were also incurred to prepare for the Company's first operated drilling activities in Australia including regulatory, health, safety and environmental costs for ATP 732, the Company's 100% owned permit in the Cooper Basin. A three well drilling program was initially planned with the first well, Caracal-1, being drilled and completed at March 31, 2013. On May 23, 2013, the Company announced that it has signed a Binding Letter of Intent to form a joint venture for the exploration and development of the Tookoonooka Permit with Australia-based Beach Energy Ltd. Under the terms of this agreement, Beach will fund the drilling of two wells as well as the acquisition of an additional 300 km^2 of 3D seismic up to a maximum cost of AUD $11.5 million to earn a 50% interest in the permit. One of the wells will be a second well in the Caracal area, with the next well to be situated on the new 3D seismic.

Expenditures of $1,751,000 were incurred to purchase an Ideco H-44 drilling rig. The Company spent a further $2,760,000 in the year to transport the rig to Australia from its point of purchase, to clear customs, to buy certain ancillary equipment required for drilling operations and to make the rig ready for use. The rig was used to drill the Caracal 1 well. The Company continues to work on ways to utilize or monetize the drilling rig.

CONVERTIBLE AND NON-CONVERTIBLE NOTES

On January 25, 2013 the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million short-term, unsecured convertible and non-convertible notes (the "Notes"). The Private Placement consists of the placement of: (i) $1,750,000 aggregate principal amount of non-convertible notes (the "Non-Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days; and (ii) $1,750,000 aggregate principal amount of convertible notes (the "Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. At June 14, 2013, there were 61,610,843 common shares issued and outstanding.

At June 14, 2013, there were 4,030,001 employee stock options outstanding with an average exercise price of $0.97 per share. Of these, 1,820,000 have vested and are exercisable at an average price of $1.09 per share. These options expire between December 31, 2013 and December 20, 2017 with an average remaining life of 3.2 years.

Trading History			**Three Months Ended March 31**			**Twelve Months Ended March 31**
	2013	2012	% Change	**2013**	2012	% Change
High	**0.80**	1.20	(33)	**1.09**	2.06	(47)
Low	**0.50**	0.78	(36)	**0.49**	0.72	(32)
Close	**0.70**	0.95	(26)	**0.70**	0.95	(26)
Volume (000s)	**3,560**	3,742	(5)	**18,932**	19,144	(1)
Shares outstanding (000s)						
Basic and diluted	**52,110**	52,110	-	52,110	52,110	-
Weighted average shares outstanding (000s)						
Basic and diluted	**52,110**	52,110	-	52,110	51,488	1

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2013 the Company had a working capital deficiency of $1.6 million, including cash and short-term deposits of $2.6 million and restricted cash of $0.1 million, compared to working capital of $25.7 million, including cash and short term deposits of $26.9 million and restricted cash of $0.1 million at March 31, 2012.

On April 16, 2013, the Company announced that it had closed a brokered private placement (the "Private Placement") of 9,500,666 common shares of the Company ("Common Shares") at a price of $0.60 per Common Share for aggregate gross proceeds of approximately $5,700,400. The Company paid the agents a cash commission of approximately $282,000, being 6.0% of the gross proceeds of the offering excluding $1,000,000 of President's list subscriptions.

Certain directors, who are shareholders of the Company, acquired 2,400,300 common shares issued pursuant to the Private Placement.

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 are expected to be sufficient to meet all of its working capital requirements for 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. Despite the expected increase in cash flow, some external financing would be prudent to help meet partner drilling commitments and strengthen the Company's balance sheet. Management is pursuing a number of alternatives simultaneously that could provide additional capital while, at the same time, maintaining or enhancing the underlying per share value. These initiatives include farm out discussions and potential sale of some non-core assets.

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 Australia – ATP 752 Cuisinier	Cuisinier to Cook pipeline, facilities upgrade, drill 5 appraisal wells	April 2013 to March, 2014	$5.9
Onshore India – CY-ONN-2005/1	3 wells	March 3, 2014(2)	$ 4.2
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014(3)	$ 5.3

(1) Translated at March 31, 2013 at an exchange rate of US $1.0000 = CAD $1.0171 and AUD $1.0000 = CAD $1.0594

(2) If the Company did not participate in the drilling of 3 wells, costs of $4,312,000 would be impaired and the Company's interest in the permit would decline.

(3) The Company is looking for a partner to participate in this permit and share the costs.

Guarantees – India Permits

($000s) CAD	Year Ended March 31, 2013	Year ended March 31, 2012
CY-ONN-2005/1 – Onshore India – year 2	$ –	$ 1,104
CY-OSN-2005/1 – Onshore India – year 3	836	820
CY-OSN-2005/1 – Onshore India – year 4	735	-
CY-OSN-2009/1 – Offshore India	154	151
Total Guarantees	**$ 1,725**	**$ 2,075**

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, 2013, 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	$ 996	$ 245	$ 498	$ 253	$ –
Decommissioning obligations	320	-	64	–	256
Total contractual obligations	$ 1,316	$ 245	$ 562	$ 253	$ 256

CONTINGENCIES

Final application for grant of permit ATP 934 has been filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the final Ministerial Grant of the tenement is received. Potential legislative changes may result in a lower commitment than shown in the table below. The Company holds a 50% operating interest in this permit. Work program consists of 500 kilometres of 2D seismic and up to seven wells.

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	$ 12.4

RELATED PARTY TRANSACTIONS

On January 25, 2013, the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million of short-term, convertible and non-convertible notes. Members of the Board of Directors of the Company subscribed for approximately 85% of the principal amount of the notes issued pursuant to the Private Placement.

SUBSEQUENT EVENTS

On April 16, 2013 the Company announced that it has closed a brokered private placement of common shares. The Company issued a total of 9,500,666 Common Shares at a price of $0.60 per Common Share for aggregate gross proceeds of approximately $5,700,400. The Company paid the Agents a cash commission of approximately $282,000, being 6.0% of the gross proceeds of the Offering excluding $1,000,000 of President's list subscriptions. A total of 2,400,300 shares of the Offering were purchased by insiders of the Company.

On April 18, 2013, the term of the Company's non-convertible notes was extended from July 24, 2013 to January 24, 2014. As consideration for the extension of the maturity date, the interest rate payable under the non-convertible notes was increased to a 10.0% fixed rate per annum from prime plus 3% effective July 25, 2013.

On May 23, 2013, Bengal entered into a Binding Letter of Intent to form a joint venture for the exploration and development of its 100%-owned Tookoonooka Block ("ATP 732") in the Cooper Basin of Australia with Beach Energy Ltd. Beach will fund Bengal's share of a two-well drilling and 3D seismic exploration and appraisal work program to a maximum of AUD$11.5 million, in order to acquire a 50% interest in ATP 732.

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	**2013**	2012	2011
Total production volumes (boepd)	**170**	135	101
Natural gas prices ($/mcf)	**2.61**	3.33	3.77
Oil and liquids prices ($/boe)	**112.01**	117.41	89.00
Total production revenue	**5,885**	4,286	1,853
Net loss	**(1,799)**	(7,209)	(3,340)
Per share – basic and diluted	**(0.03)**	(0.14)	(0.13)
Cash from operations	**(703)**	(1,142)	(2,523)
Per share – basic and diluted	**(0.01)**	(0.02)	(0.10)
Funds from operations (1)	**1,099**	(1,459)	(2,582)
Per share – basic and diluted	**0.02**	(0.03)	(0.10)
Total assets	**49,143**	43,696	25,829
Working capital (deficiency)(2)	**(1,647)**	25,722	14,063

(1) See "Non-IFRS Measurements" on page 7 of this MD&A.
(2) Calculated as current assets minus current liabilities.
(3) The Company has no non-current financial liabilities.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)	Mar 31 2013	Dec. 31 2012	Sep. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sep. 30 2011	Jun. 30 2011
Petroleum and natural gas sales	**$ 3,013**	$ 1,937	$ 437	$ 498	$ 622	$ 1,328	$ 1,017	$ 1,319
Cash from (used in) operations	**119**	(378)	315	(759)	486	(417)	159	(1,371)
Per share Basic and diluted	(0.00)	(0.01)	0.01	(0.01)	0.01	(0.01)	0.00	(0.03)
Funds from (used in) operations[1]	**1,151**	481	(471)	(62)	(635)	(402)	(430)	7
Per share Basic and diluted	**0.02**	0.01	(0.01)	0.00	(0.01)	0.00	(0.01)	0.00
Net loss	**$ (592)**	$ (151)	$ (845)	$ (211)	$ (1,424)	$ (477)	$ (4,247)	$ (1,061)
Per share Basic and diluted	**(0.01)**	(0.00)	(0.02)	0.00	(0.03)	(0.01)	(0.08)	(0.02)
Capital expenditures	**$ 1,281**	$ 9,475	$ 10,299	$ 7,326	$ 2,233	$ 4,265	$ 2,407	$ 1,933
Working capital (deficiency)	**(1,647)**	(1,436)	7,578	18,425	25,722	28,798	33,109	35,691
Total assets	**49,143**	47,584	46,557	44,484	43,696	44,899	45,696	51,072
Shares outstanding Basic and diluted	**52,110**	52,110	52,110	52,110	52,110	52,110	51,961	51,961
Operations								
Average daily production								
Natural gas (mcfd)	**229**	110	159	225	304	271	196	249
Oil and NGLs (bbls/d)	**287**	185	38	51	52	112	97	110
Combined (boepd)	**325**	203	65	89	103	157	130	152
Netback ($/boe)	**69.93**	$ 60.92	$ 40.07	$ 24.51	$ 27.27	$ 49.89	$ 51.42	$ 48.92

(1) See "Non-IFRS Measurements" on page 7 of this MD&A.

Beginning in the quarter ended March 31, 2011 and continuing through to the quarter ended December 31, 2011, oil volumes were increasing due to commencement of production from the Cuisinier 1 well in the Cooper Basin of Australia in May 2010 and the Cuisinier 2 and 3 wells in the quarter ended September 2011. Oil sales beginning in January 2012 were impacted by the temporary shut in of Cuisinier 1 on January 13, 2012 and Cuisinier 2 and 3 in August and September 2012 while the Company waited for approval of a Production License. Oil volumes increased in the quarter ended December 31, 2012 due to commencement of production from Cuisinier 4, 5, 6 and Cuisinier North 1 and Barta North 1 in October 2012 and continued into the quarter ended March 31, 2013. These wells were drilled in mid 2012 and started producing under a six month Extended Production Test in October 2012. On April 8, 2013 a production license was obtained for all current and future Cuisinier wells for a 21 year production period. In early June 2013 the Cuisinier to Cook pipeline commenced operation allowing for all eight Cuisinier to produce.

Gas volumes declined in the quarter ended September 30, 2011 due to a plant turnaround at the Oak B.C. property and are in a general decline due to natural reservoir declines. Gas volumes also declined in the quarter ended June 30, 2012 due to the removal of a rental screw compressor (due to low gas prices and the cost of the rental plus associated maintenance) and an unscheduled plant shutdown at the Oak property due to a leak in the line to the flare stack. Gas volumes declined in the quarter ended September 30, 2012 as the Company's Oak B.C. gas property was shut in due to low gas prices. This property recommenced production in December 2012.

FINANCIAL INSTRUMENTS

Financial instruments comprise cash, restricted cash and short term deposits, accounts receivable and accounts payable and accrued liabilities. 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.

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, 2013 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 judgements, 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.

a) 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.

b) Impairment Indicators

Judgements 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 assets required management to make certain judgements 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.

a) 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.

b) 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.

c) 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.

d) 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.

e) 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

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

IFRS 9 – Financial Instruments. IFRS 9, as issued, reflects the first phase of the IASB's work on the replacement of IAS 39 and applies to classification and measurement of financial assets as defined in IAS 39. The standard is effective for annual periods beginning on or after January 1, 2015. In subsequent phases, the IASB will address classification and measurement of financial liabilities, hedge accounting and derecognition.

IFRS 10 – Consolidated Financial Statements. IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. IFRS 10 replaces SIC-12 Consolidation – Special

Purpose Entities and parts of IAS 27 Consolidated and Separate Financial Statements. The standard is effective for annual periods beginning on or after January 1, 2013.

IFRS 11 – Joint Arrangements. IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or a joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation a venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 Interests in Joint Ventures and SIC-13 Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard is effective for annual periods beginning on or after January 1, 2013.

IFRS 12 – Disclosure of Interests in Other Entities. IFRS 12 applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. This standard is effective for annual periods beginning on or after January 1, 2013.

IFRS 13 – Fair Value Measurements. IFRS 13 defines fair value, sets out a single IFRS framework for measuring value and requires disclosure about fair value measurements. IFRS 13 applies to IFRS's that require or permit fair value measurements or disclosures about fair value measurement, except in specified circumstances. The standard is effective for annual periods beginning on or after January 1, 2013.

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;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Expectations that Bengal's future realized gas and oil prices will coincide with the B.C Station 2 and Brent daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cashflows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective and whether 3 wells will be drilled on this block by March 2014;*
- *Commencement of exploration and development activities on Block CY-OSN-2009/1;*

- *Obtaining Ministerial Grant of the tenement on ATP 934P in Australia and commencement of exploration activities;*
- *That Beach Energy will perform the work agreed to under the Farm-out and that further drilling activities on ATP 732P will occur;*
- *That the five wells drilled on ATP 752P in calendar Q1 and Q2 of 2013 will be completed and tied-in and that these wells will commence production and that production from all wells will continue as expected and that a sixth Cuisinier well will be drilled as part of the current year drilling program.*

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, 2013. 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.

Chayan Chakrabarty
President & Chief Executive Officer

Bryan Goudie
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, 2013 and March 31, 2012, the consolidated statements of loss and comprehensive 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, 2013 and March 31, 2012, and its consolidated financial performance and its consolidated cash flows for the years ended March 31, 2013 and March 31, 2012 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
June 17, 2013
Calgary, Canada

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2013	2012
ASSETS			
Current assets:			
Cash and cash equivalents	5	**$ 2,614**	$ 26,934
Restricted cash		**140**	135
Accounts receivable		**3,550**	1,009
Prepaid expenses and deposits		**110**	127
		6,414	28,205
Non-current assets:			
Exploration and evaluation assets	6	**26,416**	10,526
Petroleum and natural gas properties	7	**11,630**	4,735
Property, plant and equipment	8	**4,683**	230
		42,729	15,491
Total assets		**$ 49,143**	$ 43,696
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		**$ 4,622**	$ 2,483
Convertible & non-convertible notes payable	10	**$ 3,439**	–
Non-current liabilities:			
Decommissioning liability	11	**320**	228
Shareholders' equity:			
Share capital	12	**$ 86,246**	$ 86,246
Contributed surplus		**6,466**	5,779
Equity component convertible debenture	10	**25**	-
Accumulated other comprehensive income		**1,581**	717
Deficit		**(53,556)**	(51,757)
		40,762	40,985
Total liabilities and shareholders' equity		**$ 49,143**	$ 43,696

Commitments and contingencies (note 18)

Subsequent event (note 8, 21)

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Chayan Chakrabarty

Director
Chayan Chakrabarty

Director
James B. Howe

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes		2013		2012
Income					
Petroleum and natural gas revenue		$	**5,885**	$	4,286
Royalties			**(526)**		(394)
			5,359		3,892
Operating expenses					
General and administrative			**3,466**		3,585
Operating and transportation			**1,726**		1,636
Depletion and depreciation	7,8		**1,448**		420
Pre-licensing & impairment	6		**80**		4,505
Exploration & evaluation expenses			**–**		292
Share-based compensation			**487**		997
			7,207		11,435
Operating loss			**(1,848)**		(7,543)
Other income (expenses)					
Finance income			**167**		613
Finance expenses	14		**(133)**		(68)
Foreign exchange gain (loss)			**7**		(211)
			41		334
Loss before income tax			**(1,807)**		(7,209)
Deferred income tax recovery	10		**8**		-
Net loss			**(1,799)**		(7,209)
Exchange differences on translation of foreign operations			**864**		660
Total comprehensive loss for the year		$	**(935)**	$	(6,549)
Loss per share	12				
- Basic & Diluted		$	**(0.03)**	$	(0.14)
Weighted average number of shares outstanding (000s)	12				
- Basic & Diluted			**52,110**		51,488

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, 2011	**37,794,549**	**$ 62,595**	**$ 705**	**$ 4,189**	**$ –**	**$ 57**	**$ (44,548)**	**$22,998**
Net loss for the period	-	-	-	-	-	-	(7,209)	(7,209)
Comprehensive loss for the period	-	-	-		-	660	-	660
Issue of share capital (Note 12)	14,315,628	23,651	-	(146)	-	-		23,505
Expiry of warrants	-	-	(705)	705	-	-	-	-
Share-based compensation – expensed	-	-	-	997	-	-		997
Share-based compensation – capitalized	-	-	-	34	-		-	34
Balance at March 31, 2012	**52,110,177**	**$ 86,246**	**$ –**	**$ 5,779**	**$ –**	**$ 717**	**$ (51,757)**	**$ 40,985**
Balance at April 1, 2012	**52,110,177**	**$ 86,246**	**$ –**	**$ 5,779**	**$ –**	**$ 717**	**$ (51,757)**	**$ 40,985**
Net loss for the period	**-**	**-**	**-**	**-**	**-**	**-**	**(1,799)**	**(1,799)**
Comprehensive income for the period	**-**	**-**	**-**	**-**	**-**	**864**		**864**
Share-based compensation – expensed	**-**	**-**	**-**	**487**	**-**	**-**	**-**	**487**
Share-based compensation – capitalized	**-**	**-**	**-**	**200**	**-**	**-**	**-**	**200**
Convertible notes issued	**-**	**-**	**-**	**-**	**25**	**-**	**-**	**25**
Balance at March 31, 2013	**52,110,177**	**$ 86,246**	**$ –**	**$ 6,466**	**$ 25**	**$ 1,581**	**$ (53,556)**	**$ 40,762**

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	2013	2012
Operating activities			
Net loss for the year		$ **(1,799)**	$ (7,209)
Non-cash items:			
Depletion and depreciation		**1,448**	420
Pre-licensing & impairment		**927**	4,505
Accretion on decommissioning liability		**7**	5
Accretion on note payable		**45**	-
Share-based compensation		**487**	997
Deferred income tax recovery		**(8)**	-
Unrealized foreign exchange gain		**(8)**	(177)
		1,099	(1,459)
Abandonment expenditures		**–**	(3)
Change in non-cash working capital	17	**(1,802)**	320
Net cash used in operating activities		**(703)**	(1,142)
Investing activities			
Exploration and evaluation expenditures		**(16,017)**	(10,213)
Petroleum and natural gas properties		**(7,853)**	(625)
Property, plant and equipment		**(4,511)**	(230)
Change in restricted cash		**(5)**	1,092
Changes in non-cash working capital	17	**1,107**	(326)
Net cash used in investing activities		**(27,279)**	(10,302)
Financing activities			
Proceeds from issuance of shares, net of issuance costs		**–**	23,505
Proceeds from issuance of Notes		**3,461**	–
Changes in non-cash working capital	17	**38**	(82)
Net cash from financing activities		**3,499**	23,423
Impact of foreign exchange on cash and cash equivalents		**163**	355
Net (decrease) increase in cash equivalents		$ **(24,320)**	$ 12,334
Cash and cash equivalents, beginning of year		**26,934**	14,600
Cash and cash equivalents, end of year		$ **2,614**	$ 26,934

See accompanying notes to consolidated financial statements.

BENGAL ENERGY LTD.

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

Three and twelve months ended March 31, 2013 and 2012
(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 of oil and gas reserves in Australia, India and Canada. The consolidated financial statements (the “financial statements”) of the Company as at March 31, 2013 and 2012 and for the years ended March 31, 2013 and 2012 are comprised of the Company and its wholly owned subsidiaries Bengal Energy International Inc. and Bengal Energy (Australia) Pty Ltd. which are incorporated in Canada and Australia respectively. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company’s proportionate interest in such activities.

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

2. BASIS OF PREPARATION

a) Statement of compliance

These 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 14, 2013.

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 U.S. 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 the joint operation.

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%.

(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.

Depreciation

The net carrying value of drilling and workover rig components is depreciated using the unit of production method so as to depreciate the cost, less an estimated residual value of 5%, over the days in which the rig components are expected to be utilized during its useful life. Utilization days for depreciation purposes exclude initial mobilization, inter-well moves and final demobilization.

The estimated useful lives for certain rig components:

Mast and substructure	6,500 days
Draw works, rig & carrier power, genset, small wellsite office, storage containers	5,000 days
Mud tanks & mud pumps, vehicles, various small tools & handling tools, HSE equipment	3,000 days
Rebuild, inspections, re-certifications	1,000 days

Useful lives and the depreciation methods are examined on an annual calendar basis and adjustments, where applicable, are made on a prospective basis.

(g) Impairment

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 CGUs for the purpose of impairment testing, which is the lowest level at which there are identifiable cash flows 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.

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.

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 are classified as other financial liabilities, which are measured at amortized cost.

(ii) Derivative financial instruments

The Company may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments will not be used for trading or speculative purposes. The Company will 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 will be classified as FVTPL and will be recorded on the statement of financial position at fair value. Transaction costs will be recognized in profit or loss when incurred. Subsequent to initial recognition, derivatives will be 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) Convertible redeemable note:

Convertible notes can be converted into share capital at the option of the holder and the number of shares to be issued is dependent on the conversion price. The conversion price is equal to the lower of the market price of the Common Shares as of the date of issuance of the Convertible Note ($0.56/share) and the market price of the Common Shares as of the applicable Conversion Date. The liability component of the convertible note is recognized initially at the fair value of a similar liability that does not have an equity conversion option. The equity component is recognized initially as the difference between the fair value of the convertible note as a whole and the fair value of the liability component. Any transaction costs are allocated to the liability and equity components in proportion to their initial carrying amounts. The liability component accretes up to the principal balance at maturity with accretion expense included in finance cost on the statement of loss and comprehensive loss. The equity component will be reclassified to share capital on conversion. Any balance in equity that remains after the settlement of the liability is transferred to contributed surplus. The equity portion is recognized net of deferred taxes. The equity component is not re-measured subsequent to initial recognition.

(j) 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.

(k) 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.

(l) 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.

(m) Earnings (loss) per share:

Basic per share amounts are computed by dividing net earnings (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.

(n) 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.

(o) 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 and accretion of the discount on decommissioning obligations.

(p) 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.

1) The fair value of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2013 and March 31, 2012 the fair value of these balances approximated their carrying value due to their short term to maturity.

2) The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends, and the risk-free interest rate (based on government bonds).

(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.

IFRS 9 – Financial Instruments. IFRS 9, as issued, reflects the first phase of the IASB's work on the replacement of IAS 39 and applies to classification and measurement of financial assets as defined in IAS 39. The standard is effective for annual periods beginning on or after January 1, 2015. In subsequent phases, the IASB will address classification and measurement of financial liabilities, hedge accounting and derecognition.

IFRS 10 – Consolidated Financial Statements. IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. IFRS 10 replaces SIC-12 Consolidation – Special Purpose Entities and parts of IAS 27 Consolidated and Separate Financial Statements. The standard is effective for annual periods beginning on or after January 1, 2013.

IFRS 11 – Joint Arrangements. IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or a joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation a venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 Interests in Joint Ventures and SIC-13 Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard is effective for annual periods beginning on or after January 1, 2013.

IFRS 12 – Disclosure of Interests in Other Entities. IFRS 12 applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. This standard is effective for annual periods beginning on or after January 1, 2013.

IFRS 13 – Fair Value Measurements. IFRS 13 defines fair value, sets out a single IFRS framework for measuring value and requires disclosure about fair value measurements. IFRS 13 applies to IFRS's that require or permit fair value measurements or disclosures about fair value measurement, except in specified circumstances. The standard is effective for annual periods beginning on or after January 1, 2013.

4. MANAGEMENT JUDGEMENTS AND ESTIMATES

The timely preparation of the financial statements requires management to make judgements, 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

Judgements 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 assets required management to make certain judgements 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.

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 ($000s)	March 31, 2013	March 31, 2012
Cash and bank balances	**$ 2,614**	$ 3,864
Short-term deposits	**-**	23,070
	$ 2,614	$ 26,934

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

($000s)	Exploration and Evaluation Expenditures
Balance at April 1, 2011	$ 7,064
Additions	10,213
Capitalized share based compensation	29
E&E impairment loss	(4,194)
Transfer to petroleum and natural gas properties	(2,705)
Exchange adjustments	119
Balance at March 31, 2012	**$ 10,526**
Additions	16,017
Capitalized share based compensation	166
E&E impairment loss	(927)
Exchange adjustments	634
Balance at March 31, 2013	**$ 26,416**

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.

The original time period in which to complete the seismic work program on the offshore Australia AC/P 47 permit expired on March 2, 2012. On October 19, 2012, the Company was granted an extension to January 2, 2013 for the time period for completing the work program from the National Offshore Petroleum Titles Administrator (NOPTA). A meeting between the Company and NOPTA occurred in March 2013 to discuss the future of this permit. Subsequent to the March 2013 meeting, the Company made an application to NOPTA to surrender this permit and $0.8 million in costs has been impaired.

As a result of the execution of a final settlement agreement, $0.8 million of previously impaired costs for the drilling of the abandoned Hudson well in a prior year were recovered in the year ended March 31, 2013.

During the year ended March 31, 2013 E&E impairment recognized in profit and loss relates to the following (2012 - $4,194):

($000s)		Impairments
AC/P 24 – Kingtree Well offshore Australia	$	103
AC/P 47 – Offshore Australia		824
E&E Impairment - current year E&E assets	**$**	**927**
Hudson Well (recovery of prior year impairment)		(847)
Impairment charge for the year ended March 31, 2013	**$**	**80**

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

	Exploration and Evaluation Assets		
($000s)	**Australia**	**India**	**Total**
ATP 732P – Tookoonooka	$ 6,847	$ -	$ 6,847
AC/P 47 – offshore	810	-	810
CY-ONN-2005/1 – onshore	-	1,751	1,751
CY-OSN-2009/1 − offshore	-	544	544
Other	574	-	574
March 31, 2012 ($000)	**$ 8,231**	**$ 2,295**	**$ 10,526**
	Exploration and Evaluation Assets		
	Australia	**India**	**Total**
ATP 732P – Tookoonooka	$ 19,385	$ -	$ 19,385
CY-ONN-2005/1 – onshore	-	4,312	4,312
CY-OSN-2009/1 − offshore	-	833	833
Other – **Note 1**	1,886	-	1,886
March 31, 2013 ($000)	**$ 21,271**	**$ 5,145**	**$ 26,416**

Note 1: 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

	Petroleum and Natural Gas Properties $000s	Corporate Assets $000s	Total $000s
Cost:			
Balance at April 1, 2011	$ 2,168	$ 196	$ 2,364
Additions	520	105	625
Capitalized share based compensation	2	-	2
Change in decommissioning obligation	67	-	67
Transfers from E&E assets	2,705	-	2,705
Exchange adjustments	35	-	35
Balance at March 31, 2012	**5,497**	**301**	**5,798**
Additions	7,727	126	7,853
Capitalized share based compensation	19	-	19
Change in decommissioning obligation	85	-	85
Exchange adjustments	482	-	482
Balance at March 31, 2013	**$ 13,810**	**$ 427**	**$ 14,237**

	Petroleum and Natural Gas Properties $000s	Corporate Assets $ 000s	Total $000s
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2011	$ 283	$ 51	$ 334
Depletion and depreciation charge	383	37	420
Exchange adjustments	(2)	-	(2)
Impairment expense	311	-	311
Balance at March 31, 2012	**975**	**88**	**1,063**
Depletion and depreciation charge	1,300	75	1,375
Exchange adjustments	172	(3)	169
Balance at March 31, 2013	**$ 2,447**	**$ 160**	**$ 2,607**
Net carrying value			
At April 1, 2011	$ 1,885	$ 145	$ 2,030
At March 31, 2012	**$ 4,522**	**$ 213**	**$ 4,735**
At March 31, 2013	**$ 11,363**	**$ 267**	**$ 11,630**

The calculation of depletion for the year ended March 31, 2013 included $31.1 million and $0.5 million for estimated future development costs associated with proved and probable reserves in Australia and Canada respectively (March 31, 2012 - $0.8 million and $0.7 million).

In the year ended March 31, 2013 there were indicators of impairment for the Canadian Cash Generating Unit ("CGU") due to changes in forecasted commodity prices used by the Company's independent qualified reserves evaluators when compared to March 31, 2012. Accordingly, the Company tested certain CGUs for impairment and determined that there was no impairment in the aggregate carrying value of the Canadian gas property at Oak. B.C. The Company estimated the recoverable amount based on a fair value less costs to sell methodology using estimated cash flows based on both proved plus probable reserves discounted at a pre-tax discount rate of 10%.

8. PROPERTY, PLANT AND EQUIPMENT

($000s)		Rig Equipment
Balance at March 31, 2011	$	–
Additions		230
Balance at March 31, 2012	**$**	**230**
Additions		4,511
Capitalized share-based compensation		15
Balance at March 31, 2013	**$**	**4,756**
Accumulated depletion, depreciation and impairment losses:		
Balance at March 31, 2012	**$**	**–**
Depreciation charge		73
Balance at March 31, 2013	**$**	**73**
Net book value		
Balance at March 31, 2012	**$**	**230**
Balance at March 31, 2013	**$**	**4,683**

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 have been 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.

At March 31, 2013, the Company identified a trigger of impairment relating to the drilling rig being idle at March 31, 2013. The Company estimated the recoverable amount based on a fair value less costs to sell methodology using recent market transactions as a fair value estimate. It was determined that the fair value less costs to sell exceeded the net book value of the drilling rig at March 31, 2013.

On May 23, 2103 the Company entered into a Binding Letter of Intent with a leading Australian oil and gas company to Farm-in to permit ATP 732in Australia. Under the terms the Farm-in Agreement, currently being finalized, the Farmee will spend up to $11.5 million AUD to drill two wells and shoot 300 square kilometers of 3D seismic to earn a 50% interest in the permit. Upon completion of the Farm-in terms, the Farmee also has the option to become operator of the permit.

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)		2013		2012
Loss before taxes	$	(1,807)	$	7,209
Statutory tax rate		25%		26.13%
Expected income tax recovery	$	452	$	1,883
Foreign exchange		(14)		74
Stock-based compensation		(124)		(261)
Effect of change in tax rate & other		(118)		(251)
Changes in unrecognized tax asset		(188)		(1,445)
Income tax recovery	$	8	$	–

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

As of March 31 ($000s)	2013	2012
Non-capital losses	$ 28,144	$ 26,978
Net capital losses	5,998	5,878
P&NG properties	3,939	3,566
Share issue costs	765	1,147
Decommissioning obligations	320	228
	$ 39,166	$ 37,797

Income tax rates changed from 26.13 percent in fiscal 2012 to 25.0 percent in fiscal 2013 due to a reduction in federal statutory income tax rates.

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

As of March 31 ($000s)	2013	2012
Property, plant & equipment	$ 9,668	$ 3,530
Foreign exchange	339	339
Non-capital losses	(10,007)	(3,869)
	$ –	$ –

At March 31, 2013, the Company had approximately $18.5 million and $43.0 million of non-capital losses in Canada and Australia respectively (2012 - $15.6 million and $24.6 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2014 to 2033. The Australian non-capital losses have no term to expiry.

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At March 31, 2013, the Company has no deferred tax liabilities in respect of these temporary differences.

10. CONVERTIBLE AND NON-CONVERTIBLE NOTES

On January 25, 2013 the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million short-term, unsecured convertible and non-convertible notes (the "Notes"). The Private Placement consists of the placement of: (i) $1,750,000 aggregate principal amount of non-convertible notes (the "Non-Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days; and (ii) $1,750,000 aggregate principal amount of convertible notes (the "Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days.

The Convertible Notes are convertible at any time up to maturity into common shares ("Common Shares") in the capital of the Company at the option of the holder at a conversion price equal to the lower of the five day volume weighted average price of the Common Shares as at: (A) the issue date of the Convertible Notes ($0.56/share), and (B) the date of conversion of some or all of the principal amount of the Convertible Notes; provided that the conversion price shall not be lower than that conversion price that would require the Company to seek shareholder approval of the issuance of Common Shares on conversion of some or all of the principal amount of the Convertible Notes pursuant to the policies of the Toronto Stock Exchange ("TSX").

All interest payable under the Notes is payable in cash. The principal amount of the Notes shall be redeemable, at the Company's option, in whole or in part, at any time and from time to time, for cash, provided that any partial redemption is subject to a minimum redemption in the amount of $50,000 of aggregate principal amount outstanding and subject to the Holder’s rights to convert the principal amount of any Convertible Notes called for redemption. Certain directors of the Company acquired approximately $1,500,000 principal amount of the Convertible Notes and $1,500,000 principal amount of the Non-Convertible Notes issued pursuant to the Private Placement.

Upon the issuance of the Notes, the liability component of the Convertible Note was recognized initially at the fair value of a similar liability that does not have an equity conversion option. The market interest rate of 10% was used for the calculation of the liability component of the Convertible Note. The difference between the estimated future cash flows discounted at 6% (prime + 3%) and 10%, of $33,000, net of transaction fees, was recorded as equity, with the remaining $1,697,000 net of transaction fees being recorded as a liability. The discount on the notes is being accreted such that the liability at maturity will equal the face value of the note issuance of $1,750,000.

Convertible Note	**Total**	**Liability component**	**Equity Component**
	$000s	**$ 000s**	**$000s**
Gross proceeds	$ 1,750	$ 1,716	$ 34
Total cash fees	(20)	(19)	(1)
	1,730	1,697	33
Accretion on debt	22	22	-
Deferred tax impact	(8)	-	(8)
Balance at March 31, 2013	**$ 1,744**	**$ 1,719**	**$ 25**

The Non-Convertible note was issued with an interest rate considered below market rate. The market interest rate of 10% was used to calculate the implied discount on the Non-Convertible note. The difference between the estimated future cash flows discounted at 6% (prime + 3%) and 10% of $34,000 was recorded as a reduction to the face value of the debt with the remaining $1,697,000 net of transaction fees being recorded as a liability.

Non-Convertible Note	**Total**
	$000s
Gross proceeds	$ 1,750
Total cash fees	(19)
Implied Discount on Note	(34)
	1,697
Accretion on debt	23
Balance at March 31, 2013	$ 1,720

11. 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, 2013	March 31, 2012
Decommissioning liabilities, beginning of year	$ 228	$ 159
Revision	(55)	67
Additions	140	–
Expenditures	–	(3)
Accretion	7	5
Decommissioning liabilities, end of year	**$ 320**	$ 228

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, 2013 is approximately $421,000 (March 31, 2012 – $283,000) which will be incurred between 2014 and 2038. An inflation factor ranging between 1.0% and 2.0% and a risk free discount rate ranging between 1.5% and 2.75% have been applied to the decommissioning liability at March 31, 2013.

12. 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 April 1, 2011	37,794,549	$	62,595
Shares issued for cash	14,166,800		25,500
Issued on cashless exercise of stock options	73,828		–
Issued on exercise of stock options for cash	75,000		27
Transfer from Contributed Surplus	-		146
Share issue costs	-		(2,022)
At March 31, 2012 and 2013	**52,110,177**	**$**	**86,246**

(d) 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 April 1, 2011	**2,170,667**	**$ 1.38**
Granted	2,420,000	1.20
Expired	(208,335)	1.35
Forfeited	(470,667)	2.68
Exercised	(300,000)	0.74
Outstanding at March 31, 2012	**3,611,665**	**$ 1.14**
Granted	1,150,000	0.58
Forfeited	(148,333)	1.11
Expired	(416,667)	1.30
Outstanding at March 31, 2013	**4,196,665**	**$ 0.98**
Exercisable at March 31, 2013	**1,986,667**	**$ 1.09**

	Options Outstanding			Options Exercisable	
Option Price (1)	Number Outstanding	Exercise Price (2)	Remaining Life (3)	Number Exercisable	Exercise Price (2)
$ 0.36–1.25	3,075,000	$ 0.84	3.8	1,090,000	$ 0.86
$ 1.26–2.25	1,121,665	$ 1.36	2.2	896,667	$ 1.37
Total	**4,196,665**	**$ 0.98**	**3.4**	**1,986,667**	**$ 1.09**

(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, 2013	March 31, 2012
Assumptions:		
Risk free interest rate (%)	**2.0%**	2% to 4%
Expected life (years)	**5 yr**	5 yr
Expected volatility (%)(1)	**86%**	68%
Estimated forfeiture rate (%)	**6.5%**	6.0%
Weighted average fair value of options granted	**$0.40**	$0.71
Weighted average share price on date of grant	**$0.58**	$1.20

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

The fair value of stock options granted during the year and quarter ended March 31, 2013 was $454,000 (2012 - $1,710,000).

(e) Loss per share:

Earnings (loss) per share is calculated based on net loss and the weighted-average number of common shares outstanding. The Company has recorded a loss in each of the years presented and therefore any addition to basic shares outstanding is anti-dilutive.

At March 31, 2013, there were 4,196,665 (March 31, 2012 – 3,611,665) options considered anti-dilutive.

13. 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)		2013		2012
Salaries & employee benefits	$	822	$	905
Stock-based compensation[1]		496		829
General & administrative expenses	$	1,318	$	1,734

(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, 2013 include a non-recurring retirement payment to former employees of $nil (2012 - $245,582).

14. FINANCE EXPENSES

Year ended March 31 ($000s)		2013		2012
Accretion on decommissioning obligations	$	7	$	5
Performance Security Guarantee fee [1]		43		63
Interest on Notes payable		38		-
Accretion on Notes payable		45		-
Finance expenses	$	133	$	68

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

15. 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) Fair value of financial instruments:

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

(b) 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, 2013, Bengal's receivables consisted of $3.4 million (March 31, 2012 - $0.6 million) from joint venture partners and $0.2 million (March 31, 2012 - $0.4 million) of other trade receivables.

Production from the Canadian operations is marketed by the operator. Bengal has not experienced any collection issues with the operator of the property.

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, 2013, the Company had $0.1 million that were considered past due (past due is considered greater than 90 days outstanding). Bengal does not have any reason to believe these receivables will not be collected.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at March 31, 2013 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended March 31, 2013.

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.

(c) 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, accrued liabilities and Notes payable and amounted to $8.1 million at March 31, 2013 (March 31, 2012 - $2.5 million). Bengal had $2.6 million in cash (March 31, 2012 - $26.9 million), $0.1 million in restricted cash (March 31, 2012 - $0.1 million) resulting in a working capital deficit of $1.6 million at March 31, 2013 (March 31, 2012 - $25.7 million). All accounts payable, accrued liabilities and notes payable are due within one year. Subsequent to March 31, 2013 the Company closed a $5.7 million private placement of common shares (see Note 21)

As the Company is in the early stages of exploration and development, and although it is generating operating revenue, funding of most activities to date has been supplemented through the issuance of share capital. It is expected that further equity financings, as well as joint ventures and farm-ins when appropriate, will be used to fund ongoing operations and the Company's projected capital program, supplemented by cash flow from operations, working capital and debt, when the level of operations provides borrowing capacity.

(d) 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, 2013 ($000s)	CAD	AUD	U.S.D
Cash and short-term deposits	$ 2,030	$ 288	$ 274
Restricted cash	140	-	-
Accounts receivable	45	142	3,298
Accounts payable and accrued liabilities	(364)	(4,007)	(10)
Notes payable	(3,439)	-	-
	$ (1,588)	$ (3,577)	$ 3,562

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. There were no financial instruments in place to manage commodity prices during the year ended March 31, 2013.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not exposed to interest rate risk on its cash and cash equivalents at March 31, 2013 as the funds are not invested in an interest bearing instrument. The Company is exposed to interest rate risk on its Notes Payable. A 1% increase in the Prime rate would increase interest expense on the Notes by $17,500. The Company had no interest rate derivatives at March 31, 2013.

16. 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 presently does not have a credit facility in place but based on project viability may arrange separate project financing. There has been no change in capital management and no externally imposed capital restrictions during the year.

17. CHANGES IN NON-CASH WORKING CAPITAL

Year ended March 31 ($000s)		**2013**		**2012**
Accounts receivable	**$**	**(2,813)**	$	137
Prepaid expenses and deposits		**17**		(36)
Accounts payable and accrued liabilities		**2,139**		(189)
Total	**$**	**(657)**	$	(88)
Relating to:				
Operating	**$**	**(1,802)**	$	320
Financing		**38**		(82)
Investing		**1,107**		(326)
Total	**$**	**(657)**	$	(88)

Note – changes in working capital include elements of unrealized foreign exchange differences on assets and liabilities denominated in a foreign currency.

The following represents the cash interest received in each period.

Year ended March 31 ($000s)		2013		2012
Cash interest received	$	274	$	541

18. 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 Australia – ATP 752 Cuisinier	Cuisinier to Cook pipeline, facilities upgrade, drill five appraisal wells	April 2013 to March, 2014	$ 5.9
Onshore India – CY-ONN-2005/1	Three wells	March 3, 2014(2)	$ 4.2
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014(3)	$ 5.3

(1) Translated at March 31, 2013 at an exchange rate of US $1.0000 = CAD $1.0171 and AUD $1.0000 = CAD $1.0594

(2) If the Company did not participate in the drilling of three wells, costs of $4,312,000 would be impaired and the Company's interest in the permit would decline.

(3) The Company is looking for a partner to participate in this permit and share the costs.

At March 31, 2013 the Company had the following lease commitment for office space in Canada.

($000s)						
April 2013 to March 2017		Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$	996	245	498	253	-

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

Contingencies:

Final application for the grant of permit ATP 934 has been filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the final Ministerial Grant of the tenement is received. Potential legislative changes may result in a lower commitment than shown in the table below; The Company holds a 50% operating interest in this permit. The Work program consists of 500 km of 2D seismic and up to seven wells.

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	$ 12.4

19. SUPPLEMENTAL DISCLOSURE

Bengal's consolidated statement of loss and comprehensive 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, 2013 amount to $1,003,000 (2012 - $1,093,000).

20. RELATED PARTY TRANSACTIONS

On January 25, 2013, the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million of short-term, convertible and non-convertible notes. Members of the Board of Directors of the Company subscribed for approximately 85% of the principal amount of the notes issued pursuant to the Private Placement.

21. SUBSEQUENT EVENT

On April 16, 2013 the Company announced that it has closed a brokered private placement of common shares. The Company issued a total of 9,500,666 Common Shares at a price of $0.60 per Common Share for aggregate gross proceeds of approximately $5,700,400. The Company paid the Agents a cash commission of approximately $282,000, being 6.0% of the gross proceeds of the Offering excluding $1,000,000 of President's list subscriptions. A total of 2,400,300 shares of the Offering were purchased by insiders of the Company.

On April 18, 2013, the term of the Company's non-convertible notes was extended from July 24, 2013 to January 24, 2014. As consideration for the extension of the maturity date, the interest rate payable under the non-convertible notes was increased to 10.0% per annum from prime plus 3% effective July 25, 2013.

On May 23, 2013 Bengal Energy Ltd entered into a Binding Letter of Intent to enter into a Farm-out Agreement on its 100% owned Tookoonooka Block ("ATP 732") in the Cooper Basin of Australia with a leading Australian oil and gas company. The Farmee will fund Bengal's share of a two well drilling and 3D seismic exploration and appraisal work program (the "Work Program") to a maximum of AUD$11.5 million, in order to acquire a 50% interest in ATP 732.

22. SEGMENTED INFORMATION

As at March 31, 2013, 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, 2013 ($000)	Australia	Canada	India	Total
Revenue	$ 5,669	$ 216	$ -	$ 5,885
Interest revenue	82	87	(2)	167
Interest expense	-	38	-	38
Depletion and depreciation	1,255	193	-	1,448
Net loss	1,266	(2,251)	(814)	(1,799)
Exploration and evaluation expenditures	13,167	-	2,850	16,017
Petroleum and natural gas property expenditures	$ 7,876	$ (23)	$ -	$ 7,853
Property, plant & equipment expenditures	$ -	$ 4,511	$ -	$ 4,511
Impairment losses (recovery)	80	-	-	80
March 31, 2013 ($000)				
Petroleum and natural gas properties				
Cost	$ 13,065	$ 1,172	$ -	$ 14,237
Impairment loss	-	(311)	-	(311)
Accumulated depletion, depreciation and accretion	(1,828)	(468)	-	(2,296)
Net book value	$ 11,237	$ 393	$ -	$ 11,630
Exploration and evaluation assets	$ 26,393	-	$ 5,145	31,538
Accumulated impairment losses	(5,122)	-	-	(5,122)
Net book value	$ 21,271	$ -	$ 5,145	$ 26,416
Property, plant & equipment	$ –	$ 4,756	$ –	$ 4,756
Accumulated depletion, depreciation and accretion	–	(73)	–	(73)
Net book value	$ –	$ 4,683	$ –	$ 4,683

For the year ended March 31, 2012 ($000)				
	Australia	Canada	India	Total
Revenue	$ 3,908	$ 378	$ -	$ 4,286
Interest revenue	291	292	30	613
Depletion and depreciation	280	140	–	420
Net loss	(3,277)	(2,994)	(938)	(7,209)
Exploration and evaluation expenditures	8,667	-	1,546	10,213
Petroleum and natural gas property expenditures	$ 520	$ 105	$ -	$ 625
Drilling rig expenditures	$ –	$ 230	-	$ 230
Impairment losses	(4,194)	(311)	-	(4,505)
March 31, 2012 ($000)				
Petroleum and natural gas properties				
Cost	4,603	1,195	–	5,798
Impairment loss	–	(311)	–	(311)
Accumulated depletion, depreciation and accretion	(405)	(347)	–	(752)
Net book value	4,198	537	-	4,735
Exploration and evaluation assets	12,425	-	2,295	14,720
Accumulated impairment losses	(4,194)	-	-	(4,194)
Net book value	$ 8,231	$ -	$ 2,295	$ 10,526
Property, plant & equipment (net)	$ –	$ 230	$ –	$ 230

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

Bryan Mills Iradesso • Calgary, Canada
Cindy Gray - 5 Quarters Investor Relations, Inc. • Calgary, Canada

DIRECTORS

Chayan Chakrabarty
Peter D. Gaffney
James B. Howe
Stephen N. Inbusch
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)
Stephen N. Inbusch
Robert D. Steele
W.B. (Bill) Wheeler

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Stephen N. Inbusch
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
Bryan C. Goudie, Chief Financial Officer
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

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