MESSAGE TO SHAREHOLDERS

We did what we said we would do in fiscal 2011. Last year, we said Bengal would transition from land acquisition into oil exploration, initiate exploitation of our existing assets through strategic drilling and select the financial partners to share in our growth. Since the start of fiscal 2011, Bengal has raised $46.5 million through three fully-subscribed share offerings, added international expertise to our board of directors, commenced production from our Cuisinier-1 oil discovery in Australia, drilled three successful wells demonstrating a 100% drilling success in the Cuisinier Oil Pool and continued exploration efforts on our 2.2 million net acres of undeveloped land.

All of our recent activities establish a solid platform for growth. Not only does Bengal now have the funds to drill more of our promising prospects, we are more in control of our destiny than ever before with 89% operatorship of our acreage and key approvals and agreements in place.

Bengal's drilling and exploration efforts are focused in three areas: low-risk development drilling in Australia's onshore Cooper Basin, high-impact offshore drilling opportunities on two blocks in the Australian Timor Sea and onshore and offshore exploration on two blocks in India's Cauvery Basin. All three core areas offer large land positions in proven, producing basins with strong regulatory frameworks and world commodity pricing.

Our low-risk and high-impact drilling opportunities consist of both near-term catalysts and long-term upside. Our near-term catalysts are focused on the Barta Block of the Cooper Basin on Authority to Prospect ("ATP") 752P. We drilled three wells on the 360,000 acre block in fiscal 2011, including two appraisal wells offsetting our Cuisinier 1 light oil discovery and the Barta North 1 exploration well. Each new well has been cased as a potential oil well. The exploration well, located about four kilometres southwest of the Cuisinier 1, encountered oil pay in the Cretaceous Murta Sandstone. This suggests the existence of a wide fairway for Murta oil prospects offsetting the Cuisinier 1 oil discovery. Bengal has now earned a 25% working interest in the Barta Block and looks forward to ramping up exploration, appraisal and production activities on the permit.

Production from Cuisinier 1 continues to exceed expectations. Production commenced in May 2010 and continues to produce clean oil at 52 degrees API. Although the well is capable of producing more than 350 barrels per producing day, production has been restricted by the limited size of the oil storage tank at the lease and trucking access caused by flooding. We continue to look into alternative storage options to reduce production downtimes and enhance monthly production volumes. Improvements are being seen and the most recent months' data shows a dramatic rise in production uptime.

On March 11, 2011, we announced that we had been granted the formal permit to explore lands in the Cooper Basin within ATP 732P, also called the Tookoonooka Block. We have a 100% working interest in this 654,000 acre block offset by producing oil and gas fields. The Company plans to undertake a multi-well drilling program commencing early in 2012. We have already defined numerous leads and prospects on the permit. On March 1, 2011, we announced the results of an independent resource evaluation report by Ryder Scott Company-Canada related to two zones within ATP 732P. The estimates presented in the report are classified as undiscovered petroleum initially in-place and prospective resources. The report attributes resources to ATP 732P in both the Cretaceous Wyandra (oil resources) and Permian Toolachee (gas resources) sandstones. The results were summarized in a news release on March 1, 2011. The Company believes the opportunities identified on ATP 732P justify an accelerated exploration program.

While the onshore Cooper Basin in Australia offers immediate and near-term production potential, it would be hard to overstate our long-term upside in India. On February 21, 2011, BP, one of the world's largest oil and gas companies, showed significant confidence in India's hydrocarbon potential on the east coast.

BP agreed to pay Reliance Industries Limited US$7.2 billion for a 30% working interest in 23 production sharing contracts covering 270,000 square kilometres of primarily offshore exploration acreage. On India's east coast, Bengal has a 30% interest in 946 square kilometres (233,000 acres) onshore at CY-ONN-2005/1 and a 100% interest in 1,362 square kilometres (340,000 acres) offshore at CY-OSN-2009/1, suggesting tremendous potential value of Bengal's Indian assets.

At CY-ONN-2005/1 onshore we expect to crystallize prospects for three wells with drilling to begin as early as late 2012. At CY-OSN-2009/1 offshore we signed a Production Sharing Contract with the Indian Government in June 2010. Our technical review of existing 2D seismic on the block has identified a structure measuring approximately 18,000 acres. We will be targeting a 3D seismic program to further evaluate the structure and develop a follow-up drilling program. The Cauvery Basin is an active region in the southern part of the east coast of India with 28 producing oil and gas fields. Oil companies within 50 kilometres of our block have committed to spend in excess of $200 million on exploration over the next four years. The offshore Cauvery Basin includes 31 established oil and gas fields and covers an area similar to Alberta's Peace River Arch. The CY-OSN-2009-1 permit involves a light work program with seismic data obligations limited to $2 million and no drilling obligations for the next four years.

Additional long-term upside exists on Bengal's offshore prospects in the Timor Sea. In the third quarter of calendar 2011, Bengal expects to drill an exploration well into a large, shallow structure on offshore permit AC/P 24, also referred to as Kingtree 1. We have a 10% working interest in the well. In March 2009, we were awarded a 100% working interest in exploration permit AC/P 47, an offshore block in the Timor Sea measuring 3,485 square kilometres (861,000 acres). This block features potential in multiple zones. DeGolyer and MacNaughton (D&M) provided an independent "best estimate" of 590.4 million barrels of gross prospective resources on AC/P 47 as at March 31, 2009. The assessment had a low estimate of 206.5 million barrels and a high estimate of 1,456.7 million barrels. Gross prospective resources are those quantities of petroleum that are estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. There is no certainty that any portion of these resources will be recovered. If discovered, there is no certainty that it will be commercially viable or technically feasible to produce any portion of the resources. Details from this report are available on our website and in our SEDAR filings. Given the potential of AC/P 47, we're seeking a partner to accelerate both the seismic program and drilling activity of this permit.

Three successful financings, onshore Australia drilling success and momentum, and significant offshore upside position Bengal for long-term growth. Recent Cuisinier drilling success is also expected to drive increased production, cash flow and earnings in fiscal 2012. Additional momentum is expected through high-impact exploration plays at offshore permit AC/P 24 and onshore permit ATP 732P late in 2011 and early in 2012. Long-term plays in India and in the Timor Sea could start to produce results in 2013.

Bengal offers world-class assets, low-risk development drilling and high-impact exploration. We believe our inventory of oil and natural gas prospects in proven, producing basins both onshore and offshore in India and Australia provides investors with a solid platform for long-term growth.

Sincerely,

Chayan Chakrabarty

Chayan Chakrabarty
President & CEO

Bengal
ENERGY LTD.

Amended & Restated

Management's Discussion & Analysis

Years Ended
March 31, 2011 and 2010

MANAGEMENT'S DISCUSSION AND ANALYSIS

June 13, 2011

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, 2011 and 2010. Additional information relating to the Company, including detailed reserve disclosures, is included in our Annual Information Form, which will be filed on SEDAR at www.sedar.com. The reader should be aware that historical results are not necessarily indicative of future performance.

The Company'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.

RECENT HIGHLIGHTS:

Since the start of fiscal 2011, Bengal has raised $46.5 million gross through three fully-subscribed share offerings, added international expertise to its board of directors, brought one oil discovery on production, drilled three additional successful wells and continued exploration efforts on its 2.2 million net acres of undeveloped land in Australia and India.

Bengal is now well capitalized to accelerate growth through drilling and exploration efforts in three core areas: low-risk development drilling in Australia's Cooper Basin, high-impact offshore drilling on permit AC/P24 and exploration on the Company's 100% Block AC/P47 in the Australian Timor Sea, and onshore and offshore exploration on two blocks in India's Cauvery Basin. All three areas offer large land positions in proven, producing basins with strong regulatory frameworks and world commodity pricing. Bengal operates 89% of its total net acreage. Bengal's recent highlights include:

- Raised $12 million on September 29, 2010, $9 million on January 28, 2011 and $25.5 million on April 14, 2011, for a total of $46.5 million. The proceeds will help accelerate plans for development of the Company's oil and gas properties.
- Commenced production in May 2010 from the Company's Cuisinier 1 oil discovery on the Barta Block of the Cooper Basin on ATP 752P. The well continues to produce clean oil at 52 degrees API. Although the well is capable of producing more than 350 barrels per producing day (88 net), production has been restricted over the last few months due to logistical problems related to severe flooding seen earlier this year in Queensland, Australia. The operator is investigating options to improve oil sales and reduce down times.
- Drilled three additional wells on the 360,000-acre Barta Block in fiscal 2011, including two appraisal wells offsetting Cuisinier 1 and one exploration well at Barta North 1. Each new well has been cased as a potential oil well. The exploration well, located four kilometres southwest of the Cuisinier 1, encountered oil pay in the Cretaceous Murta Sandstone. This suggests the existence of a wide fairway for Murta oil prospects offsetting the Cuisinier 1 oil discovery. Bengal expects to complete and test the wells in mid-2011. Bengal now has a 25% working interest in the Barta Block.
- Received the Ministerial Grant of Authority to Prospect 732P ("ATP 732P") from the Department of Natural Resources and Mines in Queensland, Australia with an effective date of April 1, 2011. ATP 732P is in Australia's Cooper/Eromanga Basin. Bengal has a 100 percent working interest and operatorship of ATP 732P, a lightly explored permit measuring 654,321 acres. Only eight exploration wells have been drilled on the permit, three of which had hydrocarbon shows. The permit is adjacent to blocks with producing oil and gas fields from numerous depths. Seismic is planned for the fourth quarter of this year and the Company plans to undertake a multi-well drilling program commencing early 2012.

- Obtained an independent Resource Evaluation Report of ATP 732P from Ryder Scott-Canada with an effective date of February 1, 2011. The results were summarized in a news release on March 1, 2011. The Company believes the opportunities identified on ATP 732P justify an accelerated exploration program.

OUTLOOK

The Cuisinier drilling success in Australia, three over-subscribed financings in the past year, and future drilling plans for the net 2.2 million acres of lands that Bengal has diligently acquired in India and Australia provide an optimistic platform for the Company's future growth. The Company has an 89%-operated acreage position which will offer a balanced drilling portfolio, ranging from relatively lower-risk development drilling in Australia's onshore Cooper Basin to high-impact offshore drilling opportunities in the Australian Timor Sea and onshore drilling in the Company's 100%-interest and operated Cooper Basin acreage. These drilling opportunities may provide Bengal with a near-term path to production and reserves additions, and positive cash flow. In the longer term, the Company's operated 100% working interest offshore blocks in Australia and India offer opportunities to yield potentially material exploration discoveries.

AUSTRALIA – Onshore

In the Cooper Basin of Australia, two new appraisal wells and an offsetting exploration well to the Cuisinier light oil discovery (each cased as potential oil wells) were drilled on the Barta block portion of permit ATP 752P in Queensland. Following drilling, Bengal completed its final earning in the block and now holds 25% working interest in the 360,570 acre Barta Block portion of the permit. The exploration well, Barta North 1, encountered greater than four metres of oil pay in the Cretaceous Murta Sandstone on what has been mapped as a separate structure, approximately four kilometres southwest of the existing Cuisinier 1 Murta oil discovery. The Barta North 1 success is significant in that it demonstrated that a wide new drilling fairway exists for Murta oil prospects offsetting the Cuisinier 1 oil discovery. The operator has advised that the Barta North well is slated for completion and testing in the second calendar quarter of 2011.

Production from the Cuisinier 1 Murta zone discovery previously reported remains strong after having cumulatively produced over 63,000 barrels of oil to the end of April 2011 with no appreciable water cut. Since May 2010, the Cuisinier 1 well production has exceeded initial expectations and continues to show no appreciable water-cut. The Cuisinier 1 well continues to be capable of higher than 350 barrels per producing day – cumulative and monthly production has been restricted by the limited size of re-locatable oil storage tank placed at the lease and the continued trucking restrictions referred to earlier. The operator Santos continues to investigate additional storage tank options at Cuisinier 1 to reduce production downtimes. Improvements are being seen. The operator reported that 10,481 barrels of oil was delivered for sale in April 2011, averaging 340 bopd on a calendar-day basis (net 85 bopd to Bengal) over the month.

A second well, Cuisinier 2, was drilled to appraise the Cuisinier 1 Murta discovery. Cuisinier 2, located directly northeast of Cuisinier 1, encountered three separate zones of Murta oil pay. Of significance at Cuisinier 2 is that the Murta oil pay zones evident from logs look to extend 27 metres deeper than the base of perforations in Upper Murta zone of the Cuisinier 1 discovery well. A second offset appraisal well, Cuisinier 3, located south of the initial discovery well was drilled and cased as a potential Murta oil well. The operator (Santos) has advised that the Cuisinier 2 and 3 wells are slated for completion and testing in the second calendar quarter of 2011. Ultimately, further appraisal and exploration drilling will be required as the Cuisinier play has expanded significantly from a year ago. This new drilling will be potentially late in 2011 subject to the operator's rig scheduling and operations. The operator has also recently proposed that an additional 3D seismic program be undertaken late in 2011 north of Cuisinier 1 for exploration extension of this new play. Bengal will have 25% working interest in these renewed exploration efforts.

Also on permit ATP 752P, another well is anticipated to be spud by the operator before October 2011. This well will be on the Wompi block portion of ATP 752P. Bengal will be carried by the operator for all drilling costs on this next well on the Wompi block.

Also in the Cooper Basin, formal grant of Bengal's operated permit ATP 732P has been received and exploration efforts can now commence. This large 654,321 acre, 100% working interest block is offset by producing oil and gas fields and a large seismic program has been laid out in order to possibly accelerate first exploration drilling in late 2011 or early 2012. Bengal has already defined numerous leads and prospects on the permit and commissioned Ryder Scott Canada to independently evaluate the ultimate resource potential of the permit.

Australia – Offshore – Timor Sea

Bengal and its partner have agreed to drill a large, relatively shallow structure, believed prospective for oil and defined on the basis of 3D seismic data, on offshore permit AC/P24 in the Timor Sea of North West Australia. The exploration drilling location has been named Kingtree 1 (previously referred as Marshall Withers) and lies northeast on trend with the formerly productive Challis-Cassini oil field (60MM bbls cumulative oil with peak production of 43,000 bopd). The intent will be to directionally drill Kingtree 1 using a semi-submersible rig to a deviated depth of 1,750 meters (1,500 meters TVD) from 110 metres water depth. As is normal practice in the Timor Sea, the plans are to evaluate the reservoir with logs and wireline testing and then, plug and abandon the test well until such time as a full development plan can be derived. The target prospect is of a size and magnitude that it might contain, with success, recoverable oil volumes approaching a known established oil field like Challis-Cassini. The prospect sits as a separate structure approximately 15 kilometres southeast from Bengal's Katandra oil discovery. Success with Kingtree 1 could in some circumstances enable joint development of Katandra. The operator expects to spud Kingtree 1 in the third quarter of calendar 2011. Bengal holds 10% working interest in the prospect and permit AC/P24.

Elsewhere in the Timor Sea, Bengal has acquired two regional seismic lines across its 100% operated permit AC/P47. Previously announced independent resource estimates indicate this could be a very material exploration permit. The new 2D seismic was acquired to assist in the design of and planning for a 750 km2 3D program that is anticipated late in 2011. Bengal continues its efforts to seek either a JV partner or potential farmee to assist the Company with accelerating both the seismic program and seeing nearer term drilling activity on permit AC/P47.

INDIA – Offshore

Evaluation work continues on the large (340,000 acre) 100% owned and operated Production Sharing Agreement CY-OSN-2009/1 in India's offshore Cauvery basin. The first year work program includes reprocessing all available seismic records and acquiring certain 2D and 3D regional surveys previously recorded by other operators. Initial data retrieval from government sources is expected in Q2-2011.

INDIA – Onshore

On Bengal's 30% working interest, 233,000 gross acre Production Sharing Agreement CY-ONN-2005/1, work is well underway on the first year work program. Reprocessing of existing seismic data is nearly complete. Revised plans by the operator call for the acquisition of 700 km2 of 3D seismic data beginning now as early as the second half of 2011. Airborne magnetometry work will also commence in 2011. The increased 3D seismic acquisition is intended to help the joint venture to accelerate the drilling of exploration wells on the permit (3 exploration wells were planned for the minimum work program) which, subject to the seismic results, could be drilled in late 2012 at the earliest.

SUMMARY

Following three separate and fully subscribed financings since September 2010, the Company believes it is sufficiently capitalized to undertake its nearer term accelerated exploration plans and fulfill most near-term work program commitments for the large acreage position the Company holds. The Company has an attractive and large portfolio of both lower-risk and high-impact drilling opportunities. Recent drilling success at Cuisinier and on the Barta permit should drive near term and increasingly positive operating income for the Company and set the stage for future development. Potential near-term exploration success from high-impact plays at offshore permit AC/P24 and onshore permit ATP 732P, planned this year and early 2012 respectively, should create further momentum. Longer term plays in India and in the Timor Sea could bear significant fruit possibly as early as 2013. 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.

HIGHLIGHTS TABLE

$000s except per share, volumes and netback amounts	**Three Months Ended**			**Twelve Months Ended**	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Revenue					
Natural gas	**$ 125**	$ 206	$ 112	**$ 488**	$ 830
Natural gas liquids	**17**	22	12	**67**	163
Oil	**549**	52	306	**1,298**	779
Total	**691**	280	430	**1,853**	1,772
Royalties	**67**	39	46	**181**	231
% of revenue	**9.7**	13.9	10.5	**9.8**	13.0
Operating & transportation	**295**	116	189	**883**	756
Netback(1)	**328**	125	195	**788**	785
Cash flow used in operations:	**(807)**	(493)	(556)	**(2,393)**	(1,650)
Per share ($) (basic & diluted)	**(0.02)**	(0.03)	(0.02)	**(0.09)**	(0.09)
Funds used in operations(2):	**(751)**	(626)	(683)	**(2,452)**	(1,566)
Per share ($) (basic & diluted)	**(0.02)**	(0.03)	(0.02)	**(0.10)**	(0.08)
Net loss:	**(1,188)**	(1,396)	(1,031)	**(3,654)**	(4,991)
Per share ($) (basic & diluted)	**(0.03)**	(0.08)	(0.03)	**(0.14)**	(0.27)
Capital expenditures	**$ 1,879**	$ 553	$ 1,797	**$ 3,943**	$ 1,401
Property disposition proceeds	**$ –**	**$ –**	$ -	**$ –**	$ 2,111
Volumes					
Natural gas (mcf/d)	**348**	377	327	**354**	568
Natural gas liquids (boe/d)	**3**	5	3	**3**	11
Oil (bbl/d)	**56**	7	36	**39**	28
Total (boe/d @ 6:1)	**117**	75	94	**101**	134
Netback(1) ($/boe)					
Revenue	**$ 65.49**	$ 41.65	$ 49.93	**$ 50.13**	**$** 36.44
Royalties	**6.38**	5.79	5.25	**4.90**	4.74
Operating & transportation	**27.97**	17.19	21.99	**23.89**	15.53
Total	**$ 31.13**	$ 18.67	$ 22.69	**$ 21.34**	$ 16.17

(1) Netback is a non-GAAP 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-GAAP measure. The comparable GAAP measure is cash flow from operations. A reconciliation of the two measures can be found in the table on page 5.

Basis of Presentation - The financial statements and data presented herein were prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). 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. The following abbreviations are used in this MDA: boe/d means barrels of oil equivalent per day; bbl/d means barrels per day and mcf/d means thousand cubic feet of natural gas per day.

This MD&A and accompanying financial statements and notes are the three-month and 12-month periods ended March 31, 2011. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from January 1, 2011 through March 31, 2011. The terms "prior year's quarter" and "2010 quarter" are used throughout the MD&A for comparative purposes and refer to the period from January 1, 2010 through March 31, 2010.

The fiscal year for the Company is the 12-month period ended March 31, 2011. The terms "fiscal 2011," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2010 through March 31, 2011. The terms "previous year," "prior year" and "fiscal 2010" are used in the MD&A for comparative purposes and refer to the period from April 1, 2009 through March 31, 2010.

Non-GAAP 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 are not defined by GAAP in Canada and are referred to as non-GAAP measures. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net 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 flow from operations or other measures of financial performance calculated in accordance with Canadian GAAP. Funds from operations is 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 boes are calculated by multiplying the daily production by the number of days in the period.

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

	Three Months Ended			Twelve Months Ended	
$000s	**03/31/11**	03/31/10	12/31/10	**03/31/11**	03/31/10
Cash flow used in operations	**(807)**	(493)	(556)	**(2,393)**	(1,650)
Abandonment expenditures	**–**	-	-	**–**	21
Changes in non-cash working capital	**56**	(133)	(127)	**(59)**	63
Funds used in operations	**(751)**	(626)	(683)	**(2,452)**	(1,566)

Forward-looking Statements - *Certain statements contained within the MD&A, 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 TAPIS and Brent daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective;*
- *That reprocessing and acquisition of seismic will occur on Block CY-OSN-2009/1;*
- *Continuation of exploration, development and drilling activities on Permit AC/P47 offshore Australia and whether a farm-out partner will be found on acceptable terms to the Company;*
- *That the Kingtree exploration well, previously referred to as Marshall Withers, will be drilled in the third quarter of calendar 2011 and whether it will contain economic quantities of hydrocarbons;*
- *Obtaining Native Title Agreement on ATP 934P in Australia and commencement of a seismic and drilling program on ATP 732P;*
- *That Barta North Well and Cuisinier Appraisal 2 and 3 Wells will be tested in the second or third quarter of calendar 2011 and whether any of these wells will be productive.; and*
- *That the fully carried Sampdoria well will be spud on the Wompi Block prior to September 30, 2011; and*
- *That production from the Cuisinier 1 Well will continue as expected and transportation of the oil will occur.*

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 general economic conditions in Canada, the United States, India and Australia, and the continued stability of political, regulatory, tax and fiscal regimes in jurisdictions 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 MD&A:

- *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;*
- *A 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.

RESULTS OF OPERATIONS

Production

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

Production	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Natural gas (mcf/d)	**348**	377	327	**354**	568
NGLs (boe/d)	**3**	5	3	**3**	11
Oil (bbls/d)	**56**	7	36	**39**	28
Total (boe/d)	**117**	75	94	**101**	134

For the year ended March 31, 2011, production averaged 101 boe/d, down from the 134 boe/d in the prior year. Declining gas production due to the sale of the Company's Kaybob, Alberta gas property in September, 2009 was partially offset by increasing oil production in Australia from the Cuisinier 1 oil well which commenced production in May, 2010.

For the 3 months ended March 31, 2011, production averaged 117 boe/d, up from 75 boe/d produced in the prior year comparable quarter and from 94 boe/d produced in the quarter ended December 31, 2010. The increase is due to higher oil production in Australia from the Cuisinier 1 oil well. Oil production in the 3 months ended December 31, 2010 was intermittently shut in as truck access to empty the production storage tank was restricted due to flooding. Truck access improved in the current quarter but was still a factor in limiting Cuisinier production.

Pricing

Bengal's realized price for its Australian oil production has been based on the Asia Petroleum Price Index (APPI) Tapis Crude benchmark price. Effective January 1, 2011 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 has averaged US $4.65/bbl premium to Brent since January 1, 2011.

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.

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.

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

Prices and Marketing	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Average Benchmark Prices					
AECO 30 day firm ($/mcf)	**$ 3.77**	$ 5.35	$ 3.58	**$ 3.50**	$ 4.06
Dated Brent oil ($US/bbl)	**105.32**	77.37	87.34	**87.45**	70.40
Cdn/Aus exchange rate	**0.99**	0.94	1.00	**0.96**	0.93
WTI oil ($US/bbl)	**$ 94.17**	$ 78.79	$ 85.17	**$ 83.33**	$ 70.70
Bengal's Realized Price ($ CAD)					
Natural gas ($/mcf)	**$ 3.96**	$ 6.08	$ 3.72	**$ 3.77**	$ 4.00
Oil ($/bbl)	**109.06**	81.62	92.32	**92.29**	77.21
NGLs ($/bbl)	**60.40**	51.69	42.57	**50.15**	41.17
Total ($/boe)	**$ 65.49**	$ 41.65	$ 49.93	**$ 50.13**	$ 36.44

Bengal's total realized price on a boe basis increased 38% or $13.77/boe year over year as a result of increases in the market price of oil and an increase in the percentage of oil sales relative to total sales while being partially offset by lower gas prices. Current quarter realized prices increased over prior quarters due to improving oil prices and a higher proportion of oil sales to overall sales volumes.

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 ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Natural gas	**$ 125**	$ 206	$ 112	**$ 488**	$ 830
NGLs	**17**	22	12	**67**	163
Oil	**549**	52	306	**1,298**	779
Total	**$ 691**	$ 280	$ 430	**$ 1,853**	$ 1,772

Revenue for the 2011 fiscal year was 5% higher than the prior fiscal year due to a higher proportion of oil sales as a percentage of total sales and and higher oil prices in 2011 as compared to 2010. This increase in revenue was partially offset by lower gas sales volumes and realized prices.

Revenue in the current quarter increased 60% from the third quarter due to higher oil production and higher oil prices. Current quarter revenue is $411,000 or 146% higher compared to the prior year quarter due to higher oil production and higher oil prices partially offset by lower gas prices.

Royalties

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 Alberta, royalties on natural gas and NGLs are charged by the government based on an established monthly reference price. In fiscal 2010 Bengal also paid a 7.5% gross overriding royalty (GORR) on two of the Kaybob gas wells. The Company no longer has any Alberta production due to the sale of the Kaybob gas property in September 2009. The sale of the relatively higher royalty rate Kaybob gas property resulted in a decline in royalties as a percentage of revenue year over year.

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

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

Royalties by Type ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Canada Crown	**$ 12**	$ 17	$ 10	**$ 34**	$ 98
Canada gross overriding	**8**	17	7	**29**	60
Australian Government	**47**	5	29	**118**	73
Total	**$ 67**	$ 39	$ 46	**$ 181**	$ 231
$/boe	**6.38**	5.79	5.25	**4.90**	4.74
% of revenue	**9.7**	13.9	10.5	**9.8**	13.0

Royalties by Commodity	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Natural gas					
$000s	**$ 16**	$ 29	$ 14	**$ 49**	$ 122
$/mcf	**0.50**	0.85	0.46	**0.38**	0.58
% of revenue	**12.7**	14.1	12.3	**10.1**	14.6
Oil					
$000s	**$ 47**	$ 5	$ 29	**$ 118**	$ 73
$/bbl	**9.43**	7.58	8.74	**8.40**	7.23
% of revenue	**8.6**	9.3	9.5	**9.1**	9.4
NGLs					
$000s	**$ 4**	$ 5	$ 3	**$ 14**	$ 36
$/bbl	**13.92**	11.99	8.51	**10.42**	9.17
% of revenue	**23.1**	23.2	20.0	**20.8**	22.3

Operating & Transportation Expenses

Operating and transportation expenses in the 2011 fiscal year increased 17% or $126,000, compared to the prior year. Canadian costs declined due to the sale of Kaybob whereas Australian operating costs increased due to commencement of production from the Cuisinier well. The Cuisinier well has relatively higher operating costs than the Toparoa well due to trucking and road maintenance costs at Cuisinier whereas Toparoa oil is pipelined.

Australian operating costs increased $10.96/bbl in the current quarter compared to the three months ended December 31, 2010 and $9.35/bbl compared to the prior year comparable quarter due to increased higher cost Cuisinier production.

Transportation costs in Australia are incurred to transport Bengal's oil production via trucking and through pipelines from various processing facilities to the centralized Moomba facility which accepts production from 115 gas fields and 39 oil fields through approximately 5,600 kilometres of pipelines. The oil is then sent through a pipeline to Port Bonython, South Australia.

Operating Expenses ($000s)	Three Months Ended 03/31/11	03/31/10	12/31/10	Twelve Months Ended 03/31/11	03/31/10
Australia					
Operating	**$ 119**	$ 9	$ 42	**$ 269**	$ 61
Transportation	**87**	12	57	**236**	146
	206	21	99	**505**	207
Canada – Operating costs	**89**	95	90	**378**	549
Total	**$ 295**	$ 116	$ 189	**$ 883**	$ 756
Australia					
Operating - $/boe	**23.70**	14.35	12.74	**19.13**	6.00
Transportation - $/boe	**17.21**	17.66	17.19	**16.73**	14.47
Canada - $/boe	**16.14**	15.65	17.04	**16.53**	14.24
Total ($boe)	**$ 27.97**	$ 17.19	$ 21.99	**$ 23.89**	$ 15.53

General and Administration (G&A) Expenses

In the current quarter, G&A expenses increased by 31% or $261,000 to $1,102,000 from $841,000 in the prior year comparable quarter. For the fiscal year 2011 G&A expenses increased $846,000 or 35% to $3,277,000 compared to $2,431,000 in the prior fiscal year.

The increase in the current quarter is mainly due to consultant fees for preparation of resource reports on certain of the Company's properties. The increase in the fiscal year is due the cost of the resource reports as noted above and to and a one-time restructuring cost.

Stock-Based Compensation

The Company applies the fair value method for valuing stock option grants. Under this method compensation costs attributable to all share options granted are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Stock options granted under the plan can be exercised on a cashless basis, whereby the number of shares the employee receives is calculated by dividing the market price of the common shares minus the exercise price of the options by the market price of the shares and multiplying the result by the number of options exercised, net of applicable withholding taxes. Shares resulting from this formula will be issued against the exercised options without any cash consideration.

The table below provides details Bengal's stock-based compensation ("SBC") for the periods indicated:

Stock-based compensation ($000s)	Three Months Ended 03/31/11	03/31/10	12/31/10	Year Ended 03/31/11	03/31/10
SBC - options	**$ 89**	$ 148	$ 230	**$ 426**	$ 294
SBC - warrants	**55**	53	52	**215**	261
Stock-based compensation	**$ 144**	$ 201	$ 282	**$ 641**	$ 555

In February 2011, 20,000 stock options were granted to consultants. The options expire three years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $2.16 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options is estimated to be $21,000 using the Black-Scholes option pricing model.

In December 2010, 640,000 stock options were granted to employees and directors. The options expire three years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $1.39 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options is estimated to be $429,000 using the Black-Scholes option pricing model.

Fiscal 2011 SBC expense was $426,000 compared to $294,000 in the prior year. In the prior year, the fair value of most options, with the exception of the options granted in that year, had been expensed. In the current year, stock-based compensation expense increased due to amortization of the fair value of options granted in the current year as well as the prior year.

In the current year 83,333 options were exercised, 149,667 options expired and 58,333 were forfeited which had not vested. The forfeited options reduced stock-based compensation by $8,000. At March 31, 2011 there was $378,000 of stock-based compensation remaining to be amortized over the next 2 years.

Bengal recognized stock-based compensation expense of $89,000 in the current quarter compared to $148,000 in the comparable prior year's quarter. The decrease in expense in the current quarter is due to decreased fair value of options granted in fiscal 2011. SBC for the three months ended December 31, 2010 is higher as it includes a full one-third amortization of the fair value of the options granted in December 2010.

For the year ended March 31, 2011, Bengal recorded stock-based compensation related to outstanding warrants of $215,000 (2010 - $261,000) and $55,000 for the three months ended March 31, 2011 (2010 - $53,000). At March 31, 2011 the fair value of the warrants has been fully amortized. The warrants become exercisable at $2.00 per share only if the 20-day weighted average trading price of Bengal's shares reaches $4.00 per share. The warrants expire on August 13, 2011 if not exercised.

Depletion, Depreciation and Accretion (DD&A)

DD&A Expenses ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
DD&A – Australia	**$ 217**	$ 44	$ 85	**$ 412**	534
DD&A – Canada	**41**	24	48	**198**	907
Sub-total	**258**	68	133	**610**	1,441
Impairment charge	**–**	451	–	**–**	451
Total	**$ 258**	$ 519	$ 133	**$ 610**	$ 1,892
$/boe – Australia	**43.21**	70.79	25.50	**29.32**	52.95
$/boe – Canada	**7.43**	3.91	9.47	**8.68**	23.53
$/boe – Subtotal	**24.61**	10.20	15.48	**16.55**	29.65
$/boe – Impairment charge	**–**	67.27	–	**–**	9.27
$/boe – Total	**$ 24.61**	$ 77.47	$ 15.48	**$ 16.55**	$ 38.92

Depletion, depreciation and accretion (DD&A), before impairment charges, decreased $831,000 in fiscal 2011 to $610,000 from $1,441,000 in fiscal 2010. The decrease in DD&A expense is mainly due to lower production volumes and a smaller depletable cost pool in Canada due to the sale of Kaybob. Upward reserve revisions on the March 31, 2010 reserve report lowered DD&A expense per boe in Q4-2010 and for fiscal 2011.

DD&A increased by $190,000 for the three months ended March 31, 2011 compared to the prior year quarter. The increase is due to higher oil production volumes in Australia. The increase in the DD&A rate per boe from Q3-2011 to Q4-2011 is due to adding future capital costs for proved reserves for the Cuisinier 2 well while the related Cuisinier 2 proved reserve additions were offset by a downward revision in the Toparoa proved reserves.

Bengal has excluded $6.3 million from the depletion base related to Australian unproved properties at March 31, 2011 (March 31, 2010 - $3.0 million) and has $0.8 million related to the new India cost centre (March 31, 2010 - $0.5 million) which are assets considered in the preproduction stage and are not subject to depletion.

Funds From (Used In) Operations and Net Loss

For the 12 months ended March 31, 2011 funds used in operations increased to ($2,439,000) or ($0.09) per basic and diluted share compared to funds used in operations of ($1,566,000) or ($0.08) per basic and diluted share in the prior period. The decrease in funds flow of $873,000 is due to additional costs for resource report preparation and a one-time restructuring payment. The changes in non-cash working capital and abandonment expenditures are removed from the GAAP measure cash flow from (used in) operations to arrive at the non-GAAP measure funds from (used in) operations.

The loss for the 12 months ended March 31, 2011 was $3,654,000 or $0.14 per basic and diluted share compared to a loss of $4,991,000 or $0.27 per basic and diluted share in the prior fiscal year. The decreased loss was due to the prior year period including a loss on sale of assets of $943,000. Also reducing the loss is lower depletion in the current year which was partially offset by higher administration costs.

CAPITAL EXPENDITURES

Land expenditures of $991,000 are for the acquisition of 100% interest in ATP 732P, a 654,000 acre block in the Cooper Basin of Australia. Geological and geophysical expenses totaled $1,049,000 for the year ended March 31, 2011 and $251,000 in the current quarter. These costs relate to seismic acquisition, interpretation and analysis on the Company's 2.2 million net acre land base. The Company drilled three wells on the Barta Block permit in the Cooper Basin in fiscal 2011; the Barta North Well, Cuisinier 2 and Cuisinier 3. The Company paid 55% of the drilling costs of Barta North and upon rig release on November 13, 2010, Bengal's interest in the entire Barta Block, including the producing Cuisinier 1 well, prospectively increased from 14.26% to 25%. Cuisinier 2 drilling costs were paid 100% by the operator as part of its farm-in commitment and the Company paid 25% of the drilling costs of Cuisinier 3.

Capital Expenditures ($000s)	**Three months ended**			**Twelve Months Ended**	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
Land	**$ 991**	$ –	$ –	**$ 991**	$ –
Geological and geophysical	**251**	443	531	**1,049**	$ 1,377
Drilling	**637**	109	1,135	**1,772**	(261)
Completions	**–**	1	131	**131**	285
Total oil and gas additions	**1,879**	553	1,797	**3,943**	1,401
Office	**–**	–	-	**–**	–
Total expenditures	**$ 1,879**	$ 553	$ 1,797	**$ 3,943**	$ 1,401
Property disposition	–	–	–	**–**	(2,111)
Total net expenditures	**$ 1,879**	$ 553	$ 1,797	**$ 3,943**	$ (710)

Ceiling Test

No impairment was recognized under the ceiling test at March 31, 2011. The future commodity prices used in the ceiling test were based on the latest commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves.

Tax Pools

Bengal has the following tax pools available to deduct against future earnings:

Years ended March 31 ($000s)		2011		2010
Canada				
Canadian exploration expense	$	64	$	64
Canadian development expense		1,530		732
Undepreciated capital cost		640		930
Canadian foreign exploration & development		2,903		2,355
Non-capital losses carry forward		11,387		8,335
Net capital losses		5,878		5,878
Share issue costs		1,545		188
Total Canada		23,947		18,482
Australia				
Non-capital losses carry forward		18,213		13,890
Undepreciated capital cost		56		56
Share issue costs		–		21
Total Australia		18,269		13,967
Total	$	42,318	$	32,449

No tax benefit has been reflected in the financial statements as the Company does not meet the more likely than not criteria to utilize the pools and realize the benefit.

At March 31, 2011, the Company had approximately $11.2 million and $18.3 million of non-capital losses in Canada and Australia respectively (2010 - $8.3 million and $13.9 million), available to reduce future taxable income. The Canadian losses expire at various dates from March 31, 2011 to 2031. The Australian non-capital losses have no expiry.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. On June 13, 2011 there were 51,961,349 common shares issued and outstanding.

In April 2011, the Company issued 14,166,800 common shares at a price of $1.80 per Common Share for aggregate gross proceeds of $25,500,240. Proceeds of the offering, net of share issue costs of $2,053,800 were $23,446,440.

In January 2011, the Company issued 7,525,000 common shares at a price of $1.20 per Common Share for aggregate gross proceeds of $9,030,000. Proceeds of the offering, net of share issue costs of $889,500 were $8,139,500.

In September 2010, the Company issued 12,000,000 common shares at a price of $1.00 per share. The proceeds, net of share issue costs of $1,022,000, were $10,978,000.

In the period from March 31, 2010 up to the date of this report, 78,333 options were exercised on a cashless basis resulting in the issuance of 51,766 common shares, 5,000 options were exercised for cash resulting in the issuance of 5,000 shares, 321,667 options expired and 58,333 options were forfeited.

At June 13, 2011, there were 1,978,667 employee stock options outstanding with an average exercise price of $1.17 per share. Of these, 1,399,670 are exercisable at an average price of $1.09 per share. These options expire between 2011 and 2014 with an average remaining life of 2.1 years.

At June 13, 2011 there are 940,000 common share purchase warrants outstanding of which all are vested. Each warrant is exercisable upon the 20-day weighted average trading price of Bengal shares being $4.00 per share and shall entitle the holder to acquire one Bengal share at an exercise price of $2.00 until August 13, 2011.

Trading History	Three Months Ended			Twelve Months Ended	
	03/31/11	03/31/10	12/31/10	**03/31/11**	03/31/10
High	**$ 2.33**	$ 1.74	$ 1.39	**$ 2.33**	$ 1.97
Low	**1.22**	1.11	1.00	**0.92**	0.27
Close	**$ 1.95**	$ 1.35	$ 1.36	**$ 1.95**	$ 1.35
Volume (000s)	**14,266**	978	8,795	**24,783**	3,471
Shares outstanding Basic and diluted	**37,795**	18,213	30,262	**37,795**	18,213
Weighted average shares outstanding Basic and diluted	**35,532**	18,213	30,257	**25,800**	18,213

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2011 the Company had working capital of $14.1 million, including cash and short term deposits of $14.6 million and restricted cash of $1.2 million, compared to working capital of $1.3 million, including cash and short term deposits of $1.1 million and restricted cash of $0.5 million, at March 31, 2010.

The Company's liquidity has been further enhanced upon closing of the $25.5 million (gross) financing in April 2011.

The Company currently has more than sufficient funds to meet its portion of expenditure obligations as per the approved fiscal 2012 work programs. The Company's current working capital position may not provide it with sufficient capital resources to meet its minimum work obligations for all exploration periods under the various permits the Company holds and for general corporate purposes. To finance its future acquisition, exploration, development and operating costs, Bengal most likely will require financing from external sources, including issuance of new shares or executing working interest farmout arrangements. The Company is actively marketing the opportunity for interested parties to farm in to its operated oil and gas permits offshore India and Australia but there is no assurance these efforts will be successful. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to Bengal.

Contractual Arrangements

Pursuant to current production sharing contracts ("PSC") and other joint venture agreements, 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. The costs of these activities are based on minimum work budgets included in bid documents or based on planned activities and have not been provided for in the financial statements. Failure to perform minimum work program activities may result in forfeiture of the permit license. Actual costs will vary from budget.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Offshore Australia – AC/P47	750km^2 3D seismic	March 2, 2012	$8.5
Offshore Australia – AC/P24	Drill 1 exploration well	October 11, 2011	$1.7
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75 km^2 high resolution 3D seismic & 3 wells	March 3, 2014	$6.2

Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$2.0
Onshore Australia – ATP 752	Drill 1 exploration well & 1 development well. Complete & Equip 3 wells(2)	December 31, 2012	$2.6
Onshore Australia – ATP 732	Shoot 456km^2 of 2D and 50km^2 3D seismic. Drill 1 exploration well.	March 31, 2015	$6.5
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP(3)	4 years after grant of ATP	$11.7

(1) Translated at March 31, 2011 exchange rate of US $1.00 = CAD $0.9742 and AUD $1.00 = CAD $1.00

(2) Three wells are currently cased and suspended (Barta North, Cuisinier 2 and Cuisinier 3 on the Barta Block; ATP 752P) and are expected to be tested in the second or third quarter of calendar 2011. If successful, the Company will pay 25% of the completion, equipping and connection costs. The operator of the Wompi Block on ATP 752P will then pay 100% of the drilling costs to drill the Sampdoria Well as part of the Wompi Block farm-in agreement by September 30, 2011. The Company will then pay 60% of the costs of a second Wompi well by December 31, 2012 in order to complete its commitment under the Wompi Block phase of the farm-in agreement and increase its interest in the Wompi Block to 30%.

(3)The Company recently concluded negotiations with the Wongkumara People of Queensland and are awaiting partner approval and submission and acceptance of the Environmental Authority application. The Native Title Agreement will then be submitted to the Government of Queensland for approval and granting of the Authority to Prospect ("ATP"). Work program consists of 500km of 2D seismic and up to seven wells.

Guarantees – India Permits

($000s) CAD	Year ended March 31, 2011	Year ended March 31, 2010
	03/31/11	03/31/10
CY-ONN-2005/1 – Onshore India – year 1	$ 485	$ 510
CY-OSN-2005/1 – Onshore India – year 2	1,077	-
CY-OSN-2009/1 – Offshore India	152	-
Total Guarantees	**$ 1,714**	**$ 510**

These performance guarantees are not reflected in the balance sheet as they are supported by Export Development Canada.

The Company also has $135,000 in restricted cash held by its bank to secure Company credit cards.

Other

At March 31, 2011, 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	$ 127	$ 127	$ -	$ -	$ -
Asset retirement obligations	204	69	5	-	130
Total contractual obligations	$ 331	$ 196	$ 5	$ -	$ 130

RELATED PARTY TRANSACTIONS

The Company paid $120,000 in consulting fees and travel costs to a director of the Company and to a company controlled by a director (2010 - $100,425). The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At March 31, 2011, the Company has an accounts payable balance of $41,328 (2010 - $11,403) payable to this director.

SUBSEQUENT EVENTS

In April 2011the Company issued 14,166,800 common shares at a price of $1.80 per share. Proceeds of the offering, net of share issue costs of $2,053,800, were $23,446,440.

The Company had a US $0.5 million performance guarantee issued by ICICI Bank (India) Ltd. to the Government of India to guarantee the Company's share of first year exploration expenditures on its onshore Cauvery Block CY-ONN-2005/1. This performance guarantee was in turn guaranteed by Export Development Canada. These guarantees expired May 31, 2011, which is sixty days after the end of the first year of the work program.

Subsequent to year-end the Company received approval from Export Development Canada to guarantee the Performance Guarantee issued by ICICI Bank (Calgary) to the Government of India. As a result of the EDC guarantee, USD $1.1 milllion was released from restricted cash by ICICI Bank (Calgary).

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth certain annual information of the Company and has been prepared in accordance with Canadian GAAP.

($000s except per share data and prices)

Year End March 31	**2011**	2010	2009
Total production volumes (boe/d)	**101**	134	198
Natural gas prices ($/mcf)	**3.77**	4.00	7.98
Oil and liquids prices ($/boe)	**89.00**	67.05	100.00
Total production revenue	**1,853**	1,772	4,926
Net loss	**(3,654)**	(4,991)	(8,198)
Per share – basic and diluted	**(0.14)**	(0.27)	(0.45)
Cash flow from operations	**(2,393)**	(1,650)	1,773
Per share – basic and diluted	**(0.09)**	(0.09)	0.10
Funds from operations (1)	**(2,452)**	(1,556)	1,105
Per share – basic and diluted	**(0.10)**	(0.08)	0.06
Total assets	**25,524**	7,368	12,664
Working capital	**14,075**	1,275	2,189

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

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)	Quarter Ended							
	03/31/11	12/31/10	09/30/10	06/30/10	03/31/10	12/31/09	09/30/09	06/30/09
Petroleum and natural gas sales	**$ 691**	$ 430	$ 383	$ 349	$ 280	$ 413	$ 505	$ 574
Cash flow from (used-in) operations	**(807)**	(556)	(460)	(570)	(493)	(264)	(263)	(630)
Per share Basic and diluted	**(0.02)**	(0.02)	(0.02)	(0.03)	(0.03)	(0.01)	(0.01)	(0.03)
Funds from (used in) operations(1)	**(751)**	(683)	(472)	(546)	(626)	(347)	(295)	(298)
Per share Basic and diluted	**(0.02)**	(0.02)	(0.02)	(0.03)	(0.03)	(0.02)	(0.02)	(0.02)
Net loss	**$ (1,188)**	$ (1.031)	$ (684)	$ (751)	$ (1,396)	$ (885)	$ (1,848)	$ (865)
Per share Basic and diluted	**(0.03)**	(0.03)	(0.04)	(0.04)	(0.08)	(0.05)	(0.10)	(0.05)
Additions to capital assets, net	**$ 1,879**	$ 1,797	$ 174	$ 93	$ 553	$ 1,120	$ (426)	$ 154
Working capital	**14,075**	8,572	11,022	633	1,275	2,501	3,970	1,764
Total assets	**25,524**	17,611	17,357	6,684	7,368	8,928	9,159	11,839
Shares outstanding Basic and diluted	**37,795**	30,262	30,238	18,238	18,213	18,213	18,213	18,213
Operations								
Average daily production								
Natural gas (mcf/d)	**348**	327	366	381	377	422	787	684
Oil and NGLs (bbls/d)	**59**	39	41	31	12	30	53	58
Combined (boe/d)	**117**	94	102	94	75	100	184	172
Netback ($/boe)	**$ 31.31**	$ 22.69	$ 13.33	$ 16.65	$ 18.67	$ 21.39	$ 11.77	$ 16.78

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

From June 30, 2009 to March 31, 2010 volumes and revenues had been on a declining trend due to natural reservoir declines and lower commodity prices and the sale of the Kaybob gas wells in September, 2009. Beginning in the quarter ended June 30, 2010 and continuing through to the current quarter, oil volumes started increasing due to commencement of production from the Cuisinier well in the Cooper Basin of Australia in May 2010.

In the quarter ended September 30, 2009 the net loss was increased by a loss on the disposal of oil and gas assets of $943,000. The net loss in the quarter ended March 31, 2010 includes an undeveloped property impairment charge of $0.5 million.

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. Bengal has not identified any embedded derivatives in any of its contracts.

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 CONTROLS OVER FINANCIAL REPORTING ("ICFR")

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to provide reasonable assurance that material information required to be disclosed by Bengal is accumulated and communicated to the appropriate members of management 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 in providing reasonable assurance that material information required to be disclosed by the Company in reports filed with the Canadian securities regulators is accurate and complete and filed within the periods required 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 ("ICFR")

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 Canadian GAAP. 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 ineffective at March 31, 2011 due to the material weaknesses noted below.

There were no changes in the Company's internal controls or weaknesses during the year ended March 31, 2011 that have materially affected, or are reasonably likely to affect, the Company's ICFR. 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 and the Board of Directors believe that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs;
- Many of Bengal's information systems are subject to general control deficiencies including a lack of effective controls over spreadsheets, access and documentation. The Company expects that some deficiencies will continue into the future; and
- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advice on complex financial accounting issues including International Financial Reporting Standards 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 significant accounting policies used by Bengal are disclosed in Note 2 to the audited consolidated financial statements for the years ended March 31, 2011 and 2010. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstance may result in actual results or changes to estimated amounts that differ materially from current estimates. A detailed discussion of the critical accounting policies and practices of the Company helps assess the likelihood of materially different results being reported.

Reserves

Under National Instrument 51-101 ("NI 51-101") "Proved" reserves are defined as those reserves that can be estimated with a high degree of certainty to be recoverable. The level of certainty should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved reserves. It does not mean that there is a 90% probability that the Proved reserves will be recovered; it means there must be at least a 90% probability that the given amount or more will be recovered.

"Proved plus Probable" reserves are the most likely case and are based on a 50% certainty that they will equal or exceed the reserves estimated.

These oil and gas reserve estimates are made using all available geological and reservoir data, as well as historical production data. All of the Company's reserves were evaluated and reported on by an independent qualified reserves evaluator. However, revisions can occur as a result of various factors including: actual reservoir performance, changes in price and cost forecasts or a change in the Company's plans. Reserve changes will impact the financial results as reserves are used to determine the timing of asset retirement obligations, in the calculation of depletion and are used to assess whether asset impairment occurs. Reserve changes also affect other non-GAAP measurements such as finding and development costs; recycle ratios and net asset value calculations. An increase in estimated Proved reserves would result in a reduction in depletion expense.

Depletion and Depreciation

The Company follows the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to the acquisition of, exploration for and development of oil and natural gas reserves are capitalized whether successful or not. Depletion of the capitalized oil and natural gas properties and depreciation of production equipment which includes estimated future development costs less estimated salvage values are calculated using the unit-of-production method, based on production volumes in relation to estimated proven reserves.

Unproved Properties

The cost of the acquisition and evaluation of unproved properties are initially excluded from the depletion calculation. An impairment test is performed on these assets to determine whether the carrying value exceeds the fair value. Any excess in carrying value over fair value is impairment. When Proved reserves are assigned or a property is considered to be impaired, the cost of the property or the amount of the impairment will be added to the capitalized costs for the calculation of depletion.

Ceiling Test

The ceiling test is a cost recovery test intended to identify and measure potential impairment of assets. An impairment loss is recorded if the sum of the undiscounted cash flows expected from the production of the proved reserves plus the cost, less any impairment, of unproved properties does not exceed the carrying values of the petroleum and natural gas assets. An impairment loss is recognized to the extent that the carrying value of oil and gas properties exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves plus the cost, less any impairment, of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk free rate. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment as a result of this ceiling test is charged to operations as additional depletion and depreciation expense.

Asset Retirement Obligations

The Company records a liability for the fair value of legal obligations associated with the retirement of petroleum and natural gas assets in the period incurred. The liability is equal to the discounted fair value of the obligation in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes with the passage of time and the accretion is recognized as an expense in the financial statements. The total amount of the asset retirement obligation is an estimate based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total amount of the estimated cash flows required to settle the asset retirement obligation, the timing of those cash flows and the discount rate used to calculate the present value of those cash flows are all estimates subject to measurement uncertainty. Any change in these estimates would impact the asset retirement liability and the accretion expense.

Income Taxes

The determination of income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. In addition, the Company estimates when its temporary differences are expected to reverse and recognizes its tax assets and liabilities based on the legislated tax rate in those periods. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Stock-Based Compensation

The Company applies the fair value method for valuing stock option grants and warrants. This method requires the Company to make estimates of expected stock volatility, the expected hold period prior to exercising options, expected forfeitures of options and expected dividends to be declared by the Company. The stock-based compensation expense will not represent the actual fair value received by the optionees or the warrant holders as the fair value is estimated at the time of grant and is not adjusted. Due to the time period and the number of estimates involved, it is likely that the actual value of the options and warrants will differ materially from what has been recorded in the financial statements.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates, including estimates of revenues, royalties and operating costs as at a specific reporting date, but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in progress or recently completed where actual costs have not been received by the reporting date. The Company obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

FINANCIAL REPORTING UPDATE

International Financial Reporting Standards ("IFRS")

For financial periods beginning on or after January 1, 2011 International Financial Reporting Standards ("IFRS") are the generally accepted accounting principles in Canada. The changeover date for Bengal is April 1, 2011 and requires the restatement, for comparative purposes, of amounts reported by Bengal in the fiscal year ended March 31, 2011, including its opening balance sheet at April 1, 2010.

Bengal commenced its IFRS changeover project in 2009 and is currently executing a specific changeover plan which includes assessing and quantifying anticipated impacts, determining appropriate changes to accounting policies and disclosures, identifying and implementing associated changes to processes and information systems, updating and ensuring compliance with internal controls and educating staff and other stakeholders. The project to convert to IFRS is being managed by members of the accounting group, who have engaged in IFRS educational programs and continue to develop the Company's adoption to IFRS. External advisors have been retained and are assisting management with the project on an as needed basis to ensure IFRS readiness effective April 1, 2011. The Company's auditors have been and will continue to be involved throughout the process to ensure the Company's policies are in accordance with these new standards.

Management has identified key areas of impact related to the conversion to IFRS, the most significant of which is property and equipment ("PP&E"), the differences for which are as follows: The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the Company believes to be most significant.

- First time adoption exemption – IFRS 1, First-time Adoption of International Financial Reporting Standards, generally requires first-time adopters to retrospectively apply IFRS. However, the standard does provide certain optional exemptions from the retrospective application of IFRS, including the full cost exemption that allows full cost oil and gas companies to elect, at the date of transition to IFRS, to measure exploration and evaluation ("E&E") assets and development and production ("D&P") assets at the amount determined under Canadian GAAP. The Company will use this exemption.

- Re-classification of E&E expenditures from PP&E on the consolidated balance sheet – under IFRS, E&E expenditures are those that are incurred after the right to explore is obtained and before technical feasibility and commercial viability is demonstratable. E&E expenditures are capitalized and classified separately on the balance sheet. The majority of Bengal's oil and gas assets at the IFRS opening balance sheet date are in the E&E phase, and as a result, the Company will utilize the full cost exemption discussed above and re-classify approximately $3.5 million of book value at April 1, 2010 from PP&E to E&E. Under Canadian GAAP E&E assets are excluded from the depletion calculation and are assessed for impairment on an annual basis. Under IFRS, E&E assets will not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment. When an area or project is determined to be technically feasible and commercially viable, it enters the development and production phase and the associated E&E costs will be transferred to PP&E. Unrecoverable E&E costs associated with an area or project will be expensed.

- Impairment of PP&E assets – Under IFRS, impairment tests of PP&E must be performed at the cash generating unit ("CGU") level as opposed to under Canadian GAAP where the entire PP&E balance attributed to the country cost center is subject to the full cost ceiling test. Impairment calculations will be performed at the CGU level based on discounted cash flows using proven plus probable reserves. Impairments recognized under Canadian GAAP are not reversed, however under IFRS impairment can be reversed in future periods if there are indicators of reversal. The Company does not anticipate an impairment of PP&E assets upon conversion to IFRS.

- Calculation of future depletion expense for PP&E – Under IFRS, the Company has the option to use either proved reserves or proved plus probable reserves in the depletion calculation. The Company anticipates that is will use proved plus probable reserves in determining future depletion expense for PP&E.

- Asset retirement obligation ("ARO") – The major difference between current Canadian GAAP and IFRS is the discount rate used to measure ARO. Under current Canadian GAAP, a credit adjusted risk free rate is used, whereas IFRS allows the use of a risk free rate when the estimated cash flows are risked. The Company has made a preliminary decision to use a risk free interest rate. Under Canadian GAAP, existing liabilities are not re-measured using current discount rates, whereas under IFRS ARO is remeasured at each reporting date using the best estimate of expenditure to be incurred and current discount rates. A lower discount rate will increase the ARO liability and on transition to IFRS, the corresponding impact will be charged to retainded earnings or deficit.

Other key differences identified by the Company that may impact the financial statements include stock-based compensation and foreign currency translation. With respect to stock-based compensation, the Company must estimate a forfeiture rate at grant date as opposed to recognizing the impact of forfeitures when they occur. In addition, stock-based compensation will be expensed using a graded vesting schedule rather than the straight-line method utilized by the Company. At this time the Company does not anticipate the impact of the stock-based compensation differences, on transition, to be material.

The Company's foreign currency translation methods and the functional currency of the Company's foreign operations must be re-evaluated. Under IFRS, the functional currency emphasizes the currency that determines the pricing of transactions that are undertaken, rather than focusing on the currency in which those transactions are denominated. At this time the Company anticipates that its Indian subsidiary will have a functional currency change. Converting the subsidiaries' financial statements into the Company's presentation currency (Canadian dollars) will result in a cumulative translation difference. The Company will elect to utilize the first time adoption exemption available in IFRS 1 and thus set the cumulative translation difference to zero at the transition balance sheet date with the difference recorded directly to retained earnings. The charge to retained earnings at April 1, 2010 is estimated to be less than $0.1 million. Any changes in accounting policies required to address reporting and first-time adoption of IFRS will be made in consideration of the integrity of internal control over financial reporting and disclosure controls and procedures. However, the Company does not expect that any material changes in control procedures will be required as a result of the transition to IFRS.

At this time, the impact on the Company's financial position and results of operations for the accounting policy differences previously identified are not finalized. The Company anticipates completing assessing accounting policy alternatives, finalizing the opening and interim results for the fiscal year ended March 31, 2011 under IFRS and making any necessary system changes in the second quarter of calendar 2011.

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 1000, 736 – 6th Avenue SW, Calgary, Alberta T2P 3T7, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

MANAGEMENT'S RESPONSIBILITY STATEMENT

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information that is publicly disclosed. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and include estimates and assumptions based on management's best judgment. Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. Independent auditors appointed by the shareholders have examined the consolidated financial statements. Their report is presented below. The Audit Committee, consisting of independent members of the Board of Directors, have reviewed the consolidated financial statements with management and the independent auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

Chayan Chakrabarty
Chief Executive Officer

Bryan Goudie
Chief Financial Officer

Calgary, Alberta
June 13, 2011

Bengal Energy Ltd.

AUDITORS' REPORT TO THE SHAREHOLDERS

To the Shareholders

We have audited the acompanying consolidated financial statements of Bengal Energy Ltd., which comprise the consolidated balance sheets as at March 31, 2011 and 2010, the consolidated statements of operations, comprehensive loss and deficit 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 Canadian generally accepted accounting principles, 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, 2011 and 2010, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

June 13, 2011
Calgary, Canada

BENGAL ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(thousands of dollars)

As at March 31,	**2011**	**2010**
ASSETS		
Current assets:		
Cash and short-term deposits	$ 14,623	$ 1,055
Restricted cash (Note 4)	1,212	510
Accounts receivable	817	273
Prepaid expenses and deposits	95	103
	16,747	1,941
Petroleum and natural gas properties (Note 5)	8,777	5,427
	$ 25,524	$ 7,368
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 2,672	$ 666
Asset retirement obligations (Note 6)	138	93
Shareholders' equity:		
Share capital (Note 8)	62,595	43,460
Warrants (Note 8)	705	490
Contributed surplus (Note 8)	4,280	3,871
Deficit	(44,866)	(41,212)
	22,714	6,609
	$ 25,524	$ 7,368

Commitment (Note 12)
Subsequent events (Note 14)

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Chayan Chakrabarty

Director
Chayan Chakrabarty

Director
James B. Howe

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE LOSS AND DEFICIT

(thousands of dollars, except per share amounts)

Years ended March 31,		2011		2010
Revenues				
Petroleum and natural gas	$	1,853	$	1,772
Royalties		(181)		(231)
Interest		119		20
		1,791		1,561
Expenses				
General and administrative		3,277		2,431
Operating and transportation		883		756
Depletion, depreciation and accretion (Note 5)		610		1,892
Loss on sale of oil and gas properties (Note 5)		–		943
Stock-based compensation (Note 8)		641		555
Foreign exchange loss (gain)		34		(25)
		5,445		6,552
Net loss and comprehensive loss		(3,654)		(4,991)
Deficit, beginning of year		(41,212)		(36,221)
Deficit, end of year	$	(44,866)	$	(41,212)
Weighted average number of shares outstanding (000s) (Note 8)		25,800		18,213
Basic and diluted loss per share (Note 8)	$	(0.14)	$	(0.27)

See accompanying notes to consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars)

Years ended March 31,		2011		2010
Cash provided by (used in):				
Operations				
Net loss	$	(3,654)	$	(4,991)
Items not affecting cash				
Depletion, depreciation and accretion		610		1,892
Loss on sale of oil and gas assets		–		943
Stock-based compensation		641		555
Unrealized foreign exchange (gain) loss		(49)		35
Abandonment expenditures		–		(21)
Changes in non-cash working capital (Note 11)		59		(63)
Cash flow used in operations		(2,393)		(1,650)
Financing				
Proceeds from issuance of shares, net of issuance costs (Note 8)		19,120		–
Changes in non-cash working capital (Note 11)		77		5
Cash flow from financing		19,197		5
Investing				
Additions to petroleum and natural gas properties		(3,943)		(1,401)
Increase in restricted cash		(702)		(510)
Property disposition (Note 5)		–		2,111
Changes in non-cash working capital (Note 11)		1,334		(139)
Cash flow from (used in) investing		(3,311)		61
Foreign exchange gain (loss) on cash and short-term deposits		75		(37)
Increase (decrease) in cash and short-term deposits		13,568		(1,621)
Cash and short-term deposits, beginning of year		1,055		2,676
Cash and short-term deposits, end of year	$	14,623	$	1,055

		2011		2010
Interest received	$	49	$	26
Taxes paid	$	–	$	–

See accompanying notes to consolidated financial statements.

BENGAL ENERGY LTD.

Notes to Consolidated Financial Statements

Years ended March 31, 2011 and 2010
(Tabular amounts are stated in thousands of dollars except share and per share amounts)

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1. INCORPORATION

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.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Bengal have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

(a) Principles of consolidation:

These consolidated financial statements include the accounts of the Company and its wholly and majority owned subsidiaries, Avery Resources Australia (Pty) Ltd., Bengal Energy International Inc., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. respectively. All inter-entity transactions and balances have been eliminated.

(b) Cash and cash equivalents:

Cash and cash equivalents are comprised of cash and all investments with an original maturity date of three months or less.

(c) Petroleum and natural gas properties:

(i) Capitalized costs:

The full cost method of accounting is followed for petroleum and natural gas properties whereby all costs relating to the acquisition of, exploration for and development of petroleum and natural gas reserves are capitalized into a cost centre for each respective country in which the Company has operations. Such costs include lease acquisitions, geological and geophysical activities, lease rentals on undeveloped properties, the drilling of productive and non-productive wells, and administration expenses directly related to the acquisition, exploration and development activities.

(ii) Depletion and depreciation:

Total capitalized costs in each cost centre are depleted and depreciated using the unit of production method based on the Company's share of estimated gross proved oil and gas reserves as determined by independent reservoir engineers. For purposes of the depletion and depreciation calculation, proved oil and gas reserves are converted to a common unit of measure on the basis of their approximate relative energy content.

The carrying value of unproved properties, including the cost of remote exploratory test wells, is initially excluded from the depletion calculation. When proved reserves are assigned or a property is considered to be impaired, the cost of the property or the amount of the impairment will be added to the capitalized costs subject to depletion and depreciation.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized except where the sale results in a change in the rate of depletion and depreciation by 20% or more.

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

(iii) Ceiling test:

Petroleum and natural gas assets in each cost centre are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the cost of unproved properties and major development projects, less any impairment, exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the cost of unproved properties and major development projects, less any impairments, of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(d) Asset retirement obligations:

The fair value of an asset retirement obligation is recognized in the period in which it is incurred when a reasonable estimate of fair value can be made. The fair value is based on estimated reserve life, inflation and discount rates. The provision is recorded as a long-term liability, with a corresponding increase in the carrying value of the associated asset. The capitalized amount is depleted on a unit-of-production basis. Subsequent to the initial measurement of the asset retirement obligations the obligations are adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and charged to net loss for the year. The liability amount is decreased for actual abandonment costs incurred.

(e) Foreign currency translation:

The Company translates the accounts of its Australian, Indian and Irish subsidiaries, which are considered to be integrated, using the temporal method whereby monetary assets and liabilities are translated at the rates of exchange at the balance sheet dates, non-monetary assets and liabilities are translated at the rates in effect at the dates the assets or liabilities were acquired and revenues and expenses are translated at the average rates of exchange during the month in which they are recognized. Resulting gains or losses are included in the net loss.

(f) Stock-based compensation plans:

The Company uses the fair value method of accounting for stock option grants and warrants. At the date of the grant or issue, the fair value of the stock options and warrants is estimated. This fair value of the options is recorded as an expense over the vesting period of the option and warrants with a corresponding increase to contributed surplus and warrants, respectively. In determining the fair value of the stock options and warrants granted, the Black-Scholes option pricing model is used and assumptions regarding interest rates, underlying volatility of the Company's stock and expected life of the options and warrants are made. Upon the exercise of stock options or warrants, consideration received together with the amount previously recognized in contributed surplus or warrants is recorded as an increase to share capital.

(g) Per share amounts:

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.

(h) Income taxes:

The Company uses the asset and liability method of tax allocation accounting. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the enacted or substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

(i) Revenue recognition:

Revenues from the sale of natural gas, natural gas liquids and crude oil owned by the Company are recognized when title passes from the Company to its customers.

(j) Joint operations:

Significant portions of the Company's oil and gas activities are conducted jointly with others and accordingly, these financial statements reflect only the Company's interest in such activities.

(k) Financial Instruments:

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash and cash equivalents and restricted cash as held for trading, which are measured at fair value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. This is determined using the effective interest method. Accounts payable and accrued liabilities are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method.

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.

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company immediately expenses all transaction costs incurred in relation to the acquisition of a financial asset or liability.

3. FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards (“IFRS”)

On January 1, 2011 International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) will become the generally accepted accounting principles in Canada. The adoption date of March 1, 2011 will require the restatement, for comparative purposes, of amounts reported by Bengal for the year ended March 31, 2011, including the opening balance sheet as at April 1, 2010.

4. RESTRICTED CASH

Restricted cash of $1,212,000 at March 31, 2011 consists of a $135,000 guaranteed investment certificate provided to the Company’s bank that secures corporate credit cards and a US $1.1 million performance guarantee issued by ICICI Bank (India) Ltd. to the Government of India and discussed in more detail below.

On March 4, 2011, the Company, through ICICI Bank (India), issued a US $1.1 million performance guarantee to the Government of India to guarantee the Company’s share of the second year exploration expenditures on its onshore Cauvery Block CY-ONN-2005/1. Subsequent to year-end the Company received approval from EDC to guarantee the obligations of the Company to ICICI regarding the guarantee. Although EDC has guaranteed previous obligations on behalf of the Company, there can be no assurances they will continue to in the future.

5. PETROLEUM AND NATURAL GAS PROPERTIES

($000s)	Cost	Accumulated Depletion & Depreciation	Net Book Value
March 31, 2011			
Australia			
Petroleum and natural gas properties	$ 23,130	$ 15,980	$ 7,150
Other assets	56	56	–
Canada			
Petroleum and natural gas properties	3,843	3,151	692
Other assets	525	379	146
Other cost centres (India and Ireland)			
Petroleum properties – India	789	–	789
Petroleum properties – Ireland	451	451	–
	$ 28,794	$ 20,017	$ 8,777
March 31, 2010			
Australia			
Petroleum and natural gas properties	$ 18,986	$ 15,575	$ 3,411
Other assets	56	53	3
Canada			
Petroleum and natural gas properties	4,257	3,003	1,254
Other assets	525	329	196
Other cost centres (India and Ireland)			
Petroleum properties – India	563	–	563
Petroleum properties – Ireland	451	451	–
	$ 24,838	$ 19,411	$ 5,427

At March 31, 2011, undeveloped property costs of $6.3 million (March 31, 2010 - $3.0 million) have been excluded from the Australian cost centre full cost pool for the depletion calculation.

Future development costs of proved, undeveloped reserves of $15,000 for the Canadian cost centre and $351,000 for the Australian cost centre (March 31, 2010 – $15,000 and $29,000 respectively) are included in the Canadian and Australian depletion calculations.

At March 31, 2011 the India cost centre was considered to be in the preproduction stage with costs of $0.8 million (March 31, 2010 – $0.6 million for India) not subject to depletion.

Unproved Property Impairment

At March 31, 2010, the Company recorded an unproved property impairment charge of $0.5 million pertaining to its South Larne permit in Northern Ireland. The exploration license for the permit has expired and the Company does not expect any future activity on the permit.

Property Disposition

On September 24, 2009, the Company disposed of interests in certain Canadian petroleum and natural gas assets for $2,111,000, net of purchase price adjustments. The disposition also resulted in the removal of $63,000 of asset retirement obligations. The disposition of assets resulted in a change greater than 20% in the depletion rate in the Canadian cost centre and, as a result, a loss of $943,000 has been charged to net loss for the year ended March 31, 2010.

Ceiling Test

No impairment was recognized under the ceiling tests at March 31, 2011 (2010 - $nil). The prices used in the ceiling tests at March 31, 2011 were from the Degolyer and MacNaughton Canada Limited Price

Forecast as of March 31, 2011, adjusted for differentials specific to the Company's reserves, and is as follows:

	2011	2012	2013	2014	2015	Percent increase per year to 2022
WTI Cushing Oklahoma ($U.S./bbl)	$ 94.41	$ 93.00	$ 92.00	$ 91.50	$ 92.00	–
Edmonton Oil Price ($Cdn/bbl)	$ 92.57	$ 96.29	$ 97.16	$ 98.56	$ 101.08	~ 2.0%
Alberta Plantgate - Spot ($Cdn/mcf)	$ 3.58	$ 4.40	$ 5.07	$ 5.69	$ 5.97	~ 2.0%
Brent ($US/bbl)	$ 104.41	$ 99.86	$ 95.72	$ 95.60	$ 96.88	~ 2.0%

6. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from ownership interests in petroleum and natural gas assets. The Company estimates the total inflation adjusted undiscounted cash flow required to settle its asset retirement obligations at March 31, 2011 to be approximately $204,000 (March 31, 2010 - $158,000) which will be incurred between 2011 and 2024. An inflation factor of 2% has been applied to the estimated asset retirement cost at March 31, 2011 and 2010. A credit-adjusted risk-free rate of between 7% and 10% was used to calculate the initial fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

($000s)		2011		2010
Balance, beginning of period	$	93	$	179
Revisions		(3)		(14)
Additions		43		–
Liabilities settled		–		(21)
Liabilities disposed		–		(63)
Accretion		5		12
Balance, end of period	$	138	$	93

7. 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)		2011		2010
Loss before taxes	$	3,654	$	4,991
Statutory tax rate		27.63%		28.75%
Expected income tax benefit	$	1,010	$	1,435
Foreign exchange		(307)		(265)
Stock-based compensation		(177)		(160)
Effect of tax rate changes and other		386		(56)
		912		954
Change in valuation allowance		(912)		(954)
Income tax expense	$	–	$	–

The components of the net future income tax assets (liabilities) are as follows:

As of March 31 ($000s)		2011		2010
Future income tax assets:				
Non-capital losses	$	8,329	$	6,251
Net capital losses		1,469		1,469
Petroleum and natural gas properties and equipment		(1,110)		(395)
Share issue costs		386		53
Foreign exchange		(572)		(265)
Asset retirement obligations		25		24
Future income tax assets		8,727		7,137
Valuation allowance		(8,727)		(7,137)
Net future tax asset	$	–	$	–

At March 31, 2011, the Company had approximately $11.2 million and $18.3 million of non-capital losses in Canada and Australia respectively (2010 - $8.3 million and $13.9 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2012 to 2031. The Australian non-capital losses have no expiry.

8. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares.

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

(b) Issued:

($000s)	Number of shares		Amount
Balance March 31, 2009 and 2010	**18,212,783**	**$**	**43,460**
Issued on exercise of stock options	56,766		17
Shares issued for cash	19,525,000		21,030
Share issue costs	–		(1,912)
Balance March 31, 2011	**37,794,549**	**$**	**62,595**

Subsequent to year end, in April 2011, the Company issued 14,166,800 common shares at a price of $1.80 per share. Proceeds of the offering, net of share issue costs of $2,053,800, were $23,446,440.

In January 2011, the Company issued 7,525,000 common shares at a price of $1.20 per share. Proceeds of the offering, net of share issue costs of $889,500, were $8,139,500.

In September 2010, the Company issued 12,000,000 common shares at a price of $1.00 per share. Proceeds of the offering, net of share issue costs of $1,022,000, were $10,978,000.

In March 2011, 3,333 stock options were exercised based on a cashless exercise whereby 2,736 common shares were issued based on a market price of $2.01 per share on the date of exercise. The related compensation expense of $627 was reclassified from contributed surplus to share capital.

In February 2011, 5,000 stock options were exercised for $0.36 per share whereby 5,000 common shares were issued for proceeds of $1,800. The related compensation expense of $940 was reclassified from contributed surplus to share capital.

In October 2010, 33,333 stock options were exercised based on a cashless exercise whereby 24,030 common shares were issued based on a market share price of $1.29 per share on the date of exercise. The related compensation expense of $6,000 was reclassified from contributed surplus to share capital.

In May 2010, 41,667 stock options were exercised based on a cashless exercise whereby 25,000 common shares were issued based on a market share price of $1.35 per share on the date of exercise. The related compensation expense of $8,000 was reclassified from contributed surplus to share capital.

(c) Stock-based compensation - warrants:

On February 13, 2008 Bengal issued 940,000 common share purchase warrants in exchange for 1,807,692 Bengal Energy Inc. common share purchase warrants as part of the acquisition of Bengal Energy Inc. Each Bengal warrant shall vest and be exercisable as to one-third of the warrants on each of the first, second and third anniversaries of issuance or immediately upon the 20-day weighted average trading price of the Bengal shares being $4.00 per share and upon vesting shall entitle the holder to acquire one Bengal share at an exercise price of $2.00 until August 13, 2011.

The fair value of the warrants issued February 13, 2008 was estimated to be $0.7 million using the Black-Scholes option pricing model and is recorded in warrant capital and compensation expense over the 36 month vesting period of the warrants.

The table below provides details of common share purchase warrant activity:

($000s)	Number of Warrants		Amount
Balance March 31, 2009	**940,000**	**$**	**229**
Stock-based compensation expense	-		261
Balance March 31, 2010	**940,000**	**$**	**490**
Stock-based compensation expense	-		215
Balance March 31, 2011	**940,000**	**$**	**705**

(d) Stock-based compensation – stock options:

The Company has a stock option plan for directors, officers, employees and consultants of the Company whereby stock options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Stock 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.

Bengal accounts for its stock-based compensation plan using the fair value method. Under this method, a compensation cost is charged over the vesting period. Stock options granted under the plan can be exercised on a cashless basis, whereby the number of shares the employee receives is calculated by dividing the market price of the common shares minus the exercise price of the options by the market price of the shares and minus applicable withholding taxes and multiplying the result by the number of options exercised. Shares resulting from this formula will be issued against the exercised options without any cash consideration.

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2009	**1,565,366**	**$ 1.81**
Granted	652,000	1.26
Expired	(405,366)	2.92
Forfeited	(10,000)	1.60
Outstanding at March 31, 2010	**1,802,000**	**$ 1.37**
Granted	660,000	1.41
Expired	(149,667)	2.19
Forfeited	(58,333)	0.75
Exercised	(83,333)	0.45
Outstanding at March 31, 2011	**2,170,667**	**$ 1.38**
Exercisable at March 31, 2011	1,571,671	$ 1.38

	Options Outstanding			Options Exercisable	
Option Price (1)	**Number Outstanding**	**Exercise Price (2)**	**Remaining Life (3)**	**Number Exercisable**	**Exercise Price (2)**
$ 0.36	576,670	$ 0.36	3.0	576,670	$ 0.36
$ 1.26–2.25	1,301,997	$ 1.33	2.2	703,001	$ 1.33
$ 2.26–3.25	120,000	$ 3.15	0.7	120,000	$ 3.15
$ 3.26–4.50	172,000	$ 3.74	0.2	172,000	$ 3.74
Total	**2,170,667**	**$ 1.38**	**2.2**	**1,571,671**	**$ 1.38**

(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:

	Year ended March 31, 2011	Year ended March 31, 2010
Assumptions:		
Risk free interest rate (%)	2.0%	2.0%
Expected life (years)	3 yr	3 yr
Expected volatility (%)	72%	122 %
Vesting period (years)	2 yr	2 yr
Results:		
Weighted average fair value of options granted	$ 0.70	$ 0.91

The fair value of stock options granted during the year ended March 31, 2011 was estimated to be $450,000 and for the year ended March 31, 2010 the fair value was estimated to be $592,000.

Bengal has not incorporated an estimated forfeiture rate for stock options that will not vest, rather the Company accounts for actual forfeitures as they occur.

In the year ended March 31, 2011 there was 640,000 stock options granted with an exercise price of $1.39 and 20,000 stock options granted with an exercise price of $2.16. These options have a three year term, vest one-third immediately and one-third on each of the next two anniversary dates.

The table below provides details Bengal's stock-based compensation ("SBC") for the periods indicated:

($000s)	Year Ended March 31, 2011	Year ended March 31, 2010
SBC – options	$ 426	$ 294
SBC - warrants	215	261
Balance, end of year	**$ 641**	$ 555

(e) Contributed surplus:

A reconciliation of contributed surplus is provided below:

($000s)	Year Ended March 31, 2011	Year ended March 31, 2010
Balance, beginning of year	**$ 3,871**	**$ 3,577**
Stock-based compensation expense	426	294
Exercise of options	(17)	-
Balance, end of year	**$ 4,280**	**$ 3,871**

(f) Per share amounts:

Per share amounts are calculated using losses and the weighted average number of common shares outstanding. The Company has recorded a loss in each of the last two years and therefore any addition to basic shares outstanding is anti-dilutive.

The weighted average number of shares outstanding for the year ended March 31, 2011 were 25,800,431 (2010 – 18,212,783).

At March 31, 2011, there were 2,170,667 (2010 – 1,802,000) options that were anti-dilutive and at March 31, 2011 there were 940,000 warrants (2009 – 940,000) that were anti-dilutive.

9. FINANCIAL RISK MANAGEMENT

(a) Fair value of financial instruments:

Financial instruments comprise cash and short-term deposits, restricted cash, 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.

(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. As at March 31, 2011, Bengal's receivables consisted of $0.6 million (March 31, 2010 - $0.1 million) from joint venture partners and $0.2 million (March 31, 2010 - $0.2 million) of other trade receivables.

In Canada, production from the Oak property is marketed by the operator. Bengal has not experienced any collection issues with the operator of the Oak wells.

In Australia, production is purchased by a consortium led by one of Australia's largest public oil and gas companies which is also the operator of Bengal's production. Bengal has a Crude Oil Purchase Agreement with this purchaser and has not experienced any collection problems to date.

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

At March 31, 2011, the Company had no receivables that were considered past due (past due is considered greater than 90 days outstanding).

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 has a zero balance in the allowance for doubtful accounts as at March 31, 2011 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the years ended March 31, 2011 or 2010.

Cash and short-term deposits, 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 and accrued liabilities and amounted to $2.7 million at March 31, 2011. Bengal had $14.6 million in cash, $1.2 million in restricted cash and working capital of $14.1 million at March 31, 2011.

As the Company is in the early stages of exploration and development, and although it is generating operating revenue, the Company’s current working capital position may not provide it with sufficient capital resources to meet its minimum work obligations for all exploration periods under various permits the Company holds and for general corporate purposes. 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. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to Bengal.

(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 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 had no forward exchange rate contracts in place as at March 31, 2011.

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, 2011 ($000s)				
	Total	**CAD**	**AUD**	**USD**
			CAD $ Equivalent	
Cash and short-term deposits	14,623	10,396	3,732	495
Restricted cash	1,212	135	–	1,077
Accounts receivable	817	173	205	439
Accounts payable and accrued liabilities	(2,672)	(457)	(2,215)	–
Balance sheet exposure	13,980	10,247	1,722	2,011

A 5% strengthening or (weakening) of the CAD as compared to the AUD or USD would have increased or (decreased) net loss by $220,000 respectively.

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 Tapis reference price, which tracks WTI but is also affected by refinery capacity in South East Asia and the U.S. There were no financial instruments in place to manage commodity prices during the period ended March 31, 2011.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk on its cash and cash equivalents that have a floating interest rate. The Company is receiving 1.2% interest on its guaranteed investment certificates in Canada and 4.55% on term deposits in Australia. A 1.0% decrease in interest rates would have resulted in a $46,000 increase to net loss and cash flow used in operating activities in the year ended March 31, 2011 and a 1.0% increase in interest rates would decrease net loss and cash flow used in operating activities by $46,000 over the same period. The Company had no interest rate swaps or hedges at March 31, 2011.

10. 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. The Company currently has no debt.

In order to maintain or adjust the capital structure, the Company may from time to time issue shares (if available on reasonable terms), 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.

11. CHANGES IN NON-CASH WORKING CAPITAL

Years Ended March 31 ($000s)		2011		2010
Accounts receivable	$	(544)	$	562
Prepaid expenses and deposits		8		15
Accounts payable and accrued liabilities		2,006		(774)
Total	$	1,470	$	(197)
Relating to:				
Operating	$	59	$	(63)
Financing		77		5
Investing		1,334		(139)
Total	$	1,470	$	(197)

12. COMMITMENTS

Work Programs

Pursuant to current production sharing contracts ("PSC") and other joint venture agreements, 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. The costs of these activities are based on minimum work budgets included in bid documents or based on planned activities and have not been provided for in the financial statements. Failure to perform minimum work program activities may result in forfeiture of the permit license. Actual costs will vary from budget.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Offshore Australia – AC/P 47	750 km^2 3D seismic	March 2, 2012	$8.5
Offshore Australia – AC/P 24	Drill 1 exploration well	October 11, 2011	$1.7
Onshore India – CY-ONN-2005/1	625 km^2 3D seismic + 75 km^2 high resolution 3D seismic & 3 wells	March 3, 2014	$6.2
Offshore India – CY-OSN-2009/1	310 km 2D seismic & 81 km^2 3D seismic	August 15, 2014	$2.0
Onshore Australia – ATP 752P	Drill 1 exploration well & 1 development well. Complete & Equip 3 wells(2)	December 31, 2012	$2.6
Onshore Australia – ATP 732P	Shoot 456 km^2 of 2D and 50 km^2 3D seismic . Drill 1 exploration well.	March 31, 2015	$6.5
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP(3)	4 years after grant of ATP	$11.7

(1) Translated at March 31, 2011 exchange rate of US $1.00 = CAD $0.9742 and AUD $1.00 = CAD $1.00

(2) Three wells are currently cased and suspended (Barta North, Cuisinier 2 and Cuisinier 3 on the Barta Block; ATP 752P) and are expected to be tested in the second or third quarter of calendar 2011. If successful, the

Company will pay 25% of the completion, equipping and connection costs. The operator of the Wompi Block on ATP 752P will then pay 100% of the drilling costs to drill the Sampdoria Well as part of the Wompi Block farm-in agreement by September 30, 2011. The Company will then pay 60% of the costs of a second Wompi well by December 31, 2012 in order to complete its commitment under the Wompi Block phase of the farm-in agreement and increase its interest in the Wompi Block to 30%.

(3) Recently concluded negotiations with the Wongkumara People of Queensland and are awaiting partner approval and submission and acceptance of the Environmental Authority application. The Native Title Agreement will then be submitted to the Government of Queensland for approval and granting of the Authority to Prospect ("ATP"). Work program consists of 500km of 2D seismic and up to seven wells.

Other

At March 31, 2011 the Company had the following lease commitment for office space in Canada:

($000s)		
Fiscal 2012 – April 2011 to March 2012	$	127

13. RELATED PARTY TRANSACTIONS

The Company paid $120,000 in consulting fees and travel costs to a director of the Company and to a company controlled by a director (2010 - $100,425). The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At March 31, 2011, the Company has an accounts payable balance of $41,328 (2010 - $11,403) payable to this director.

14. SUBSEQUENT EVENTS

In April 2011, the Company issued 14,166,800 common shares at a price of $1.80 per share. Proceeds of the offering, net of share issue costs of $2,053,800, were $23,446,440.

The Company has a US $0.5 million performance quarantee issued by ICICI Bank (India) Ltd. to the Government of India to guarantee the Company's share of first year exploration expenditures on its onshore Cauvery Block CY-ONN-2005/1. This performance guarantee was in turn guaranteed by Export Development Canada. These guarantees expired May 31, 2011 which is sixty days after the end of the first year work program.

Subsequent to year-end the Company received approval from Export Development Canada to guarantee the Performance Guarantee issued by ICICI Bank (Calgary) to the Government of India. As a result of the EDC guarantee, USD $1.1 milllion was released from restricted cash by ICICI Bank (Calgary).

15. SEGMENTED INFORMATION

Year ended Mar 31, 2011 ($000s)	Australia	Canada	Other[1]	Total
Revenue, net of royalties	$ 1,180	$ 492	$ –	$ 1,672
Net loss	(761)	(2,653)	(240)	(3,654)
Petroleum and natural gas property expenditures	$ 3,680	$ 37	$ 226	$ 3,943

As at Mar 31, 2011 ($000s)	Australia	Canada	Other[1]	Total
Petroleum and natural gas properties				
Cost	$ 23,186	$ 4,368	$ 1,240	$ 28,794
Accumulated depletion, depreciation and accretion	(16,036)	(3,530)	(451)	(20,017)
Net book value	$ 7,150	$ 838	$ 789	$ 8,777

[1] Other is new cost centres considered to be in the pre-production stage and includes India.

Year ended Mar 31, 2010 ($000s)	Australia	Canada	Other[2]	Total
Revenue, net of royalties	$ 706	$ 835	$ –	$ 1,541
Net loss	(614)	(4,174)	(203)	(4,991)
Petroleum and natural gas property expenditures	$ 597	$ 591	$ 213	$ 1,401
Property disposition	$ -	$ 2,111	$ -	$ 2,111

As at Mar 31, 2010 ($000s)	Australia	Canada	Other[2]	Total
Petroleum and natural gas properties				
Cost	$ 19,042	$ 4,782	$ 1,014	$ 24,838
Accumulated depletion, depreciation and accretion	(15,628)	(3,332)	(451)	(19,411)
Net book value	$ 3,414	$ 1,450	$ 563	$ 5,427

[2] Other is new cost centres considered to be in the pre-production stage and includes India.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Allens Arthur Robinson • 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

DIRECTORS

Richard A.N. Bonnycastle
Chayan Chakrabarty
Richard N. Edgar
Peter D. Gaffney
James B. Howe
Robert Steele
Ian J. Towers (Chairman)

GOVERNANCE AND DISCLOSURE COMMITTEE

All Directors are members of this Committee

AUDIT COMMITTEE

Richard A.N. Bonnycastle
James B. Howe (Chairman)
Robert Steele

RESERVES COMMITTEE

Richard N. Edgar
Peter D. Gaffney (Chairman)
Ian J. Towers

COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & CEO
Bryan Goudie, Chief Financial Officer
James A. Mott, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING

TSX: BNG