Bengal
ENERGY LTD.

International exploration & production

Management's Discussion & Analysis

Three and Nine Months Ended December 31, 2011 and 2010

MANAGEMENT'S DISCUSSION AND ANALYSIS – FEBRUARY 13, 2012

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 unaudited interim Consolidated Financial Statements and accompanying notes for the three and nine months ended December 31, 2011 and the audited Consolidated Financial Statements and accompanying notes for the years ended March 31, 2011 and 2010.

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 in Canadian dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

OUTLOOK

The Company entered the third fiscal quarter of 2012 with a very strong balance sheet showing approximately $29.1 million in cash, no debt and a balanced portfolio of exploration and development drilling opportunities on its extensive land base in Australia and India. The price the Company receives for all of its oil sales in Australia is based on the Dated Brent reference price which is currently trading at approximately a US $10 premium to WTI.

AUSTRALIA – Onshore

Authority to Prospect ("ATP") 752 Barta Block

In the Barta Block on ATP 752, where Bengal owns a 25% working interest, the operating company plans to drill three development wells and one exploration well in calendar Q2 2012 after the end of the wet season and as a follow up to its four successful exploration and appraisal wells. The development wells will be drilled directly offsetting existing producing wells at Cuisinier targeting the Murta formation. The step-out exploration well will be drilled some 2.9 kms northeast of the Cuisinier 1 discovery on a satellite structure. This well will target Murta, Birkhead and Hutton reservoirs on a structure defined by 3D seismic.

Planning is underway for the shooting of a new 3D seismic survey during the second half of 2012 or early 2013. This seismic will be acquired north of and adjoining the current 3D seismic data set and Cuisinier wells and development area, and will be aimed at imaging Murta, Birkhead and Hutton anomalies, both structural and stratigraphic.

The previously equipped Barta North 1 Murta oil well will be tied into the existing Cuisinier 1 facility via 4.5 km of pipeline. Construction is set to commence upon completion of the wet season in mid Q2, with commissioning planned for the end of Q2 2012.

The operating company has also initiated preliminary engineering work for the tie-in of all Cuisinier production to the existing Cook production facility. This 7.5 km pipeline, which is expected to be operational in early 2013, will eliminate the trucking from the current Cuisinier 1 facility and improve run-times and netbacks in the field.

The Cuisinier 1 well has been operating through an Extended Production Test (EPT) as required under the framework of an ATP, and, with the timeframe of the current EPT set to expire on December 17, 2011, an extension was applied for on December 9, 2011 by the operating company to the Queensland Regulator, DEEDI (Department of Employment, Economic Development and Innovation). On January 13, 2012, DEEDI advised the Operating Company that the application to extend the EPT was being reviewed, but asked that the Cuisinier 1 well be shut-in temporarily until the extension was approved or a Cuisinier

Production License (PL) granted. The original PL application and accompanying Initial Development Plan were submitted to DEEDI by the operating company in October 2009. Subsequent negotiations followed with DEEDI as to the areal extent of the application area, and as a result, a revised PL was submitted on January 13, 2012. The current net impact to Bengal of the shut-in Cuisinier 1 production is 70 bopd.

ATP 732 Tookoonooka Block

The acquisition of approximately 400 line km of 2D and 50 square km of 3D seismic data at ATP 732 (Tookoonooka Block) has been completed and interpretation is underway. In conjunction with this seismic data acquisition, a complete evaluation of aeromagnetic and gravity data on this block has been completed, and will be integrated with the seismic data evaluation. This should allow for drill locations to be selected by late February, and an application will be submitted to the Queensland Government for approval of the Company's drilling plans on this permit. The Company currently plans to commence exploratory drilling with an initial three-well campaign commencing in calendar Q2 2012 after the end of the wet season, upon the receipt of all regulatory approvals from the Queensland Government, and subject to the outcome of the seismic data interpretation. The planning, groundwork and resourcing of drilling, equipping and facility support services for this exploration campaign is well underway.

The Company continues to review further options for the acceleration of its 2012 drilling programs.

ATP 934 Barrolka Block

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

<u>Australia - Offshore</u>

AC/P 47 Block

At AC/P 47, Bengal has applied for an extension to the term of this large offshore permit to Australia's Northern Territory Government Department of Resources. If this extension is received, the Company then plans to shoot, process and interpret a minimum of 750 square km of 3D seismic on this permit during 2012 and Q1 2013. This should allow Bengal to either commit by June 2, 2013 to a well to be drilled by March 2, 2014, or if no acceptable prospects are identified from the seismic interpretation then the permit will be relinquished.

AC/P 24 Block

Bengal has been advised by the operator of the permit at AC/P 24 that an extension request has been filed for and received for the Kingtree prospect for one year and that initial applications for a retention lease for the Katandra discovery have been made.

Analysis of gas encountered while drilling the Kingtree well indicates the presence of a residual oil column evidencing trap leakage. A northern and separate fault bound closure will be further reviewed for potential future drilling.

<u>India - Onshore</u>

CY-ONN-2005/1 Block

On Bengal's 30% working interest, 233,000 gross acre Block CY-ONN-2005/1 located in onshore Cauvery Basin, Bengal and its joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, have commenced the acquisition of a 3D seismic program of approximately 600 square km. Because of weather-related delays in the acquisition program, the operator currently anticipates that approximately 50% of this planned seismic data acquisition will be completed by the end of calendar Q2 2012, with the rest of the program to be completed later in 2012 subject to weather conditions. As well, airborne magnetometry work will be carried out over the permit in association with the seismic acquisition program. The seismic acquisition and airborne magnetometry work are intended to help the joint venture define drilling locations on the permit. A recent gas discovery was made immediately west of the block at Vadateru, however details of this discovery have not yet been released.

India - Offshore

CY-OSN-2009/1 Block

Evaluation work is continuing on this 340,000 acre, 100% owned and operated Block CY-OSN-2009/1 in India's offshore Cauvery basin. Activity includes reprocessing of certain available seismic records and acquiring 2D and 3D surveys previously recorded in this region. Additional pre-existing seismic data has been located and is being integrated with the existing seismic data set. The acquisition of additional seismic data in early 2012 is designed to accelerate the timing of the drilling of an exploration well. Recent competitor activity in the local area, including the $7.2 billion acquisition by BP of a 30% interest in a number of blocks held by Reliance and the recently announced exploration discoveries by Cairn India in nearby Sri Lankan waters, provide encouragement for acceleration of the Bengal activity.

SUMMARY

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. Development and exploratory drilling planned for the first half of calendar 2012 at Cuisinier 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 drilling success on permit ATP 732P, planned for 2012, should create further momentum. Longer term plays in India and in the Timor Sea could begin to add value 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

$000s except per share, volumes and netback amounts	Three Months Ended			Nine Months Ended	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
Revenue					
Natural gas	**$ 92**	$ 112	$ 67	**$ 250**	$ 364
Natural gas liquids	**23**	12	13	**53**	49
Oil	**1,213**	306	937	**3,361**	749
Total	**1,328**	430	1,017	**3,664**	1,162
Royalties	**121**	46	95	**337**	114
% of revenue	**9.1**	10.7	9.3	**9.2**	9.8
Operating & transportation	**486**	189	316	**1,324**	588
Netback[(1)]	**721**	195	606	**2,003**	460
Cash flow from (used in) operations:	**(417)**	(556)	159	**(1,628)**	(1,586)
Per share ($) (basic & diluted)	**(0.01)**	(0.02)	0.00	**(0.03)**	(0.07)
Funds from (used in) operations:[(2)]	**(206)**	(683)	(430)	**(628)**	(1,701)
Per share ($) (basic & diluted)	**0.00**	(0.02)	(0.01)	**(0.01)**	(0.05)
Net (loss):	**(477)**	(1,094)	(4,247)	**(5,785)**	(2,466)
Per share ($) (basic & diluted)	**(0.01)**	(0.04)	(0.08)	**(0.11)**	(0.08)
Capital expenditures	**$ 4,327**	$ 1,797	$ 2,407	**$ 8,667**	$ 2,064
Volumes					
Natural gas (mcf/d)	**271**	327	196	**238**	356
Natural gas liquids (boe/d)	**4**	3	3	**3**	4
Oil (bbl/d)	**108**	36	94	**103**	33
Total (boe/d @ 6:1)	**157**	94	130	**146**	96
Netback[(1)] ($/boe)					
Revenue	**$ 92.03**	$ 49.93	$ 86.21	**$ 91.50**	$ 44.00
Royalties	**8.43**	5.25	8.01	**8.42**	4.31
Operating & transportation	**33.71**	21.99	26.78	**33.07**	22.27
Total	**$ 49.89**	$ 22.69	$ 51.42	**$ 50.01**	$ 17.42

(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 IFRS 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 following information is based on the interim consolidated financial statements of the Company at December 31, 2011, as prepared by management. The financial data included in this interim MD&A is in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") that are expected to be effective or available for early adoption by the Company as at March 31, 2012, the date of the Company's first annual reporting under IFRS. The effective date of the transition to IFRS was April 1, 2010. The transition to IFRS has been reflected by restating previously reported financial statements for 2010. Previously, the Company's financial statements were prepared under Canadian generally accepted accounting principles ("CGAAP"). The adoption of IFRS does not impact the underlying economics of the Company's operations or its cash flows. Note 15 to the interim consolidated financial statements for the period ended December 31, 2011 contain detailed descriptions of the Company's adoption of IFRS, including reconciliations of the consolidated financial statements previously prepared under CGAAP to those under IFRS.

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 MD&A: 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 for the three and nine month periods ended December 31, 2011. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from October 1, 2011 through December 31, 2011. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from October 1, 2010 through December 31, 2010. The term "prior quarter" refers to the three months ended September 30, 2011. The term "calendar Q2 2012" refers to the period April to June 2012.

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 do not have any standardized meaning under IFRS and previous GAAP 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 income (loss) per share. Netbacks equal total revenue less royalties and operating and transportation expenses calculated on a boe basis. Management utilizes these measures to analyze operating performance. Funds from operations is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net income, cash flow from operations or other measures of financial performance calculated in accordance with IFRS. 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			Nine Months Ended	
$000s	**12/31/11**	12/31/10	09/30/11	**12/31/11**	12/31/10
Cash flow from (used in) operations	**(417)**	(768)	159	**(1,628)**	**(1,798)**
Changes in non-cash working capital	**211**	(127)	(589)	**1,000**	**(115)**
Funds from (used in) operations	**(206)**	(895)	(430)	**(628)**	**(1,913)**

RESULTS OF OPERATONS

Production

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

Production	Three Months Ended			Nine Months Ended	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
Natural gas (mcf/d)	**271**	327	196	**238**	356
NGLs (boe/d)	**4**	3	3	**3**	4
Oil (bbls/d)	**108**	36	94	**103**	33
Total (boe/d)	**157**	94	130	**146**	96

For the three months ended December 31, 2011, total oil, natural gas and natural gas liquids (NGLs) production averaged 157 boe/d, an increase of 67% from the 94 boe/d produced in the prior year comparable quarter. The increase in production is due to commencement of production from Cuisinier 2 and 3 in August, 2011 partially offset by natural declines from the Company's Oak British Columbia gas property.

Partially offsetting the commencement of production from Cuisinier 2 and 3, oil volumes were impacted in the current quarter due to bushfires and wet roads which limited truck access to the Cuisinier site for 23 days in the quarter. Gas volumes increased in the current quarter compared to the quarter ended September 30, 2011 due to a maintenance shutdown of the Oak facility for part of the the prior quarter.

YTD production averaged 146 boe/d compared to 96 boe/d in the prior YTD. The increase is due to commencement of Cuisinier 2 and 3 production offset by natural declines from the Oak, BC gas property

Pricing

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

Prices and Marketing	Three Months Ended						Nine Months Ended			
		12/31/11		12/31/10		09/30/11		**12/31/11**		12/31/10
Average Benchmark Prices										
AECO 30 day firm ($/mcf)	**$**	**3.47**	$	3.58	$	3.72	**$**	**3.64**	$	3.72
Dated Brent oil ($US/bbl)		**108.90**		87.34		112.08		**112.32**		81.40
Number of CAD$ for 1 AUD$		**1.04**		1.00		1.03		**1.03**		0.95
Number of CAD$ for 1 USD$	**$**	**1.02**	$	1.00	$	0.98	**$**	**0.99**	$	0.95
WTI oil ($US/bbl)	**$**	**97.43**	$	85.17	$	87.90	**$**	**96.35**	$	78.78
Bengal's Realized Price ($CAD)										
Natural gas ($/mcf)	**$**	**3.68**	$	3.72	$	3.73	**$**	**3.83**	$	3.71
Oil ($/bbl)		**122.62**		92.32		109.51		**118.88**		82.95
NGLs ($/bbl)		**60.45**		42.57		50.64		**60.50**		47.32
Total ($/boe)	**$**	**92.03**	$	49.93	$	86.21	**$**	**91.50**	$	44.00

Bengal's total realized price on a boe basis increased for the three months ended December 31, 2011 compared to the prior year quarter by $42.10 to $92.03 due to higher oil prices and an increased proportion of sales from oil volumes. Current quarter prices increased by $5.82 compared to the prior quarter due to a declining CAD compared to the USD which is the currency oil revenues are paid in.

Bengal's realized price for its Australian oil production had 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 $5.19/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.

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 ($000s)	Three Months Ended						Nine Months Ended			
		12/31/11		12/31/10		09/30/11		**12/31/11**		12/31/10
Natural gas	**$**	**92**	$	112	$	67	**$**	**250**	$	364
NGLs		**23**		12		13		**53**		49
Oil		**1,213**		306		937		**3,361**		749
Total	**$**	**1,328**	$	430	$	1,017	**$**	**3,664**	$	1,162

Petroleum and natural gas sales for the third quarter of the 2012 fiscal year were 209% or $898,000 higher than the prior year comparable period. Increased oil volumes contributed $812,000 to the increase in revenues while $100,000 of the increase is due to higher oil prices. These changes were offset by minor changes in gas volumes and prices.

YTD revenue increased 215% or $2,502,000 due to higher product prices and higher oil volumes. Increased oil volumes contributed $2,288,000 to the increase in revenues while $326,000 of the increase is due to higher oil prices. These changes were offset by minor changes in gas volumes and 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 Australia, oil royalties are based on a government-established rate of 10% plus a Native Title royalty which is typically 1%. The royalty rate is applied to gross revenues after deducting an allowance for transportation and operating costs resulting in an effective rate of less than 10%.

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

Royalties by Type ($000s)	Three Months Ended			Nine Months Ended	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
Canada Crown	**$ 6**	$ 10	$ 6	**$ 18**	$ 22
Canada gross overriding	**8**	7	3	**17**	21
Australian Government	**107**	29	86	**302**	71
Total	**$ 121**	$ 46	$ 95	**$ 337**	$ 114
$/boe	**8.51**	5.25	8.01	**8.45**	4.31
% of revenue	**9.1**	10.7	9.3	**9.2**	9.8
Royalties by Commodity	**Three Months Ended**			**Nine Months Ended**	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
Natural gas					
$000s	**$ 10**	$ 14	$ 5	**$ 24**	$ 33
$/mcf	**0.41**	0.46	0.26	**0.36**	0.34
% of revenue	**11.2**	12.3	7.0	**9.5**	9.1
Oil					
$000s	**$ 107**	$ 29	$ 86	**$ 302**	$ 71
$/bbl	**10.85**	8.74	10.07	**10.70**	7.82
% of revenue	**8.9**	9.5	9.2	**9.0**	9.4
NGLs					
$000s	**$ 4**	$ 3	$ 4	**$ 11**	$ 10
$/bbl	**15.84**	8.51	13.95	**15.00**	9.45
% of revenue	**17.0**	20.0	27.5	**21.0**	20.0

For the third quarter of fiscal 2012, royalties were 163%, or $75,000 higher than the previous comparable period due to higher production volumes and product prices. Royalties per boe increased as there was a $14,000 Crown Royalty credit included in the prior year figures.

Operating & Transportation Expenses

Operating and transportation expenses in the third quarter of fiscal2012 increased $297,000 to $486,000 compared to $189,000 in the prior year comparable quarter. The increase is due to higher oil volumes in Australia. Operating costs increased by $11.72 per boe in the current quarter compared the prior year quarter. The increase is due to a higher proportion of higher cost oil volumes compared to gas volumes.
Operating and transportation costs increased by $170,000 ($6.93 per boe) in the current quarter compared to the prior quarter due commencement of production from Cuisinier 2 and 3.

YTD operating and transportation costs increased $736,000 or 125% compared to the prior year period. The increase is due to commencement of Cuisinier 2 and 3 oil production in Australia. Operating costs increased by $10.30 per boe YTD compared the prior year period. The increase is due to a higher proportion of higher cost oil volumes compared to gas volumes.

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

Operating Expenses ($000s)	Three Months Ended			Nine Months Ended	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
Australia					
Operating	**$ 222**	$ 42	$ 122	**$ 570**	$ 150
Transportation	**177**	57	150	**501**	149
	399	99	272	**1,071**	299
Canada – Operating costs	**87**	90	44	**253**	289
Total	**$ 486**	$ 189	$ 316	**$ 1,324**	$ 588
Australia					
Operating - $/boe	**22.41**	12.74	14.23	**20.16**	16.59
Transportation - $/boe	**17.93**	17.19	17.59	**17.71**	16.47
Canada - $/boe	**19.24**	17.04	13.47	**21.53**	16.66
Total ($boe)	**$ 33.71**	$ 21.99	$ 26.78	**$ 33.07**	$ 22.27

General and Administration (G&A) Expenses

In the third quarter of fiscal 2012, G&A expenses decreased by 17% or $173,000 over the prior quarter as the prior quarter included a onetime retirement payment to a vice president. YTD expenses increased by $487,000 to $2,641,000 or 23% due to higher Geological and Geophysical consulting costs and travel costs as the Company's operated activities in Australia and India increase.

General and Administrative Expenses ($000s)	Three Months Ended			Nine Months Ended	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
G&A	**$ 853**	$ 915	$ 1,026	**$ 2,641**	$ 2,154

Share-Based Compensation

The Company uses the Black-Scholes pricing model to estimate the fair value of the options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding increase to contributed surplus.

Bengal recognized share-based compensation ("SBC") expense of $169,000 for the current quarter compared to $254,000 in the comparable prior year's period. The decrease is due to some option grants becoming fully vested and therefore fully amortized in the current quarter.

YTD SBC expense is high as two new hires received options in August and September of 2011.

Stock-Based Compensation ($000s)	Three Months Ended			Nine Months Ended	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
SBC - options	**$ 169**	$ 236	$ 240	**$ 686**	$ 383
SBC - warrants	**–**	18	-	**–**	58
Stock-based compensation	**$ 169**	$ 254	$ 240	**$ 686**	$ 441

In June 2011, 750,000 stock options were granted to employees, directors and selected consultants. The options expire five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $1.32 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 $597,000 using the Black-Scholes option pricing model.

In August 2011, 200,000 stock options were granted to a new employee. The options expire five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $1.05 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 $126,000 using the Black-Scholes option pricing model.

In September 2011, 200,000 stock options were granted to a new employee. The options expire five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $1.25 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 $148,000 using the Black-Scholes option pricing model.

Stock-based compensation related to outstanding warrants is nil for the three months ended December 31, 2011 as the warrants are fully amortized (December 31, 2010 - $18,000). The warrants expired on August 13, 2011.

Depletion and Depreciation

Depletion and depreciation increased by $32,000 for the three months ended December 31, 2011 over the comparable prior year's period. The decrease in Canada is due to lower gas volumes from the Company's Oak B.C. gas property and the increase in Australia is due to higher Cuisinier production volumes. Depletion per boe declined due to the addition of probable reserves on the Company's Cuisinier property in the March 31, 2011 reserve report prepared by DeGolyer and MacNaughton Canada Limited dated May 17, 2011.

DD&A Expenses ($000s)	**Three Months Ended**			**Nine Months Ended**	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
DD&A – Australia	**$ 91**	$ 50	$ 75	**$ 229**	$ 121
DD&A – Canada	**35**	44	29	**98**	144
Total	**$ 126**	$ 94	$ 104	**$ 327**	$ 265
$/boe – Australia	**9.18**	15.06	8.78	**8.09**	13.45
$/boe – Canada	**7.71**	8.32	8.90	**8.32**	8.29
$/boe – Total	**$ 8.72**	$ 10.91	$ 8.81	**$ 8.16**	$ 10.06

In the nine months ended December 31, 2011 the Company reported a $4,089,000 impairment loss relating to exploration and evaluation assets. The impairment relates to inception to date costs on permit AC/P2 4 which were determined to be impaired after drilling and abandoning the Kingtree well in October 2011 and drilling costs charged by the operator in the period for the dry and abandoned Hudson well which was drilled in 2008.

Funds from (used in) Operations and Net Loss

For the three months ended December 31, 2011 funds used in operations decreased to $144,000 or ($0.00) per basic and diluted share compared to funds used in operations of $683,000 or ($0.02) per basic and diluted share in the prior comparable period. The decrease in funds used in operations is due to increased operating income from the Company's Australian properties partially offset by a one-time retirement payment to a Vice President.

For the three months ended December 31, 2011 cash flow used in operations decreased to $355,000 or $0.01 per basic and diluted share compared to cash flow used in operations of $556,000 or $0.02 per basic and diluted share in the prior comparable period. The decrease in cashflow used is mainly due to improved net operating income due to increased oil sales volumes.

The loss for the three months ended December 31, 2011 was $264,000 or ($0.01) per basic and diluted share compared to a loss of $1,094,000 or $0.04 per basic and diluted share in the prior fiscal year. The lower loss is due to improved net operating income due to increased oil sales volumes.

CAPITAL EXPENDITURES

YTD expenditures of $8,605,000 include $4,376,000 to shoot 400 km of 2D and 50 square km of 3D seismic on onshore Australia permit ATP 732P, $851,000 for seismic and geological and geophysical work on the Company's two India permits, $1,111,000 to drill the Kingtree well offshore Australia in the Timor Sea and $702,000 in charges from the operator of the Hudson well which was drilled in 2008. The negative drilling costs in the three months ended December 31, 2011 are due to actual costs being less than estimated at September 30, 2011. YTD completion costs are to complete and equip Cuisinier 2, 3 and Barta North 1 and to tie-in Cuisinier 2 and 3.

Capital Expenditures ($000s)	**Three Months Ended**			**Nine Months Ended**	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
Geological and geophysical	**$ 4,416**	$ 368	$ 696	**$ 5,294**	$ 635
Drilling	**(251)**	1,088	1,362	**1,813**	1,088
Completions	**100**	129	349	**1,498**	129
Total expenditures	**$ 4,265**	$ 1,585	$ 2,407	**$ 8,605**	$ 1,852
Exploration & evaluation expenditures	**4,174**	1,456	2,055	**8,166**	1,723
Development & production expenditures	**91**	129	352	**439**	129
Total net expenditures	**$ 4,265**	$ 1,585	$ 2,407	**$ 8,605**	$ 1,852

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. On February 13, 2012, there were 52,110,127 common shares issued and outstanding.

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 $2,022,000, were $23,478,000.

In June 2011, 750,000 options were issued with an exercise price of $1.32. In August 2011, 200,000 options were issued with an exercise price of $1.05 and in September 2011, 200,000 options were issued with an exercise price of $1.25 per share.

In the period April 1, 2011 up to the date of this report, 225,000 options were exercised on a cashless basis resulting in the issuance of 73,828 common shares, 75,000 options were exercised resulting in the issuance of 75,000 shares, 464,000 options expired and 208,000 options were forfeited.

Share-based compensation of $146,025 has been moved from contributed surplus to equity as a result of the option exercises.

At February 13, 2012, there were 2,348,668 employee stock options outstanding with an average exercise price of $1.14 per share. Of these, 1,458,670 are exercisable at an average price of $1.05 per share. These options expire between 2012 and 2016 with an average remaining life of 2.9 years.

Trading History	**Three Months Ended**			**Nine Months Ended**	
	12/31/11	12/31/10	09/30/11	**12/31/11**	12/31/10
High	**$ 1.48**	$ 1.39	$ 1.44	**$ 2.06**	$ 1.72
Low	**0.72**	1.00	1.00	**0.72**	0.92
Close	**$ 0.80**	$ 1.36	$ 1.25	**$ 0.80**	$ 1.36
Volume (000s)	**5,070**	8,795	4,722	**15,401**	10,517
Shares outstanding Basic and diluted	**52,110**	30,262	51,961	**52,110**	30,262
Weighted average shares outstanding Basic and diluted	**52,088**	30,257	51,961	**51,282**	22,515

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2011 the Company had working capital of $28.8 million, including cash and short term deposits of $29.1 million and restricted cash of $0.1 million, compared to working capital of $14.1 million, including cash and short term deposits of $14.6 million and restricted cash of $1.2 million at March 31, 2011.

The Company currently has sufficient funds to meet its portion of expenditure obligations as per the approved fiscal 2012 work programs. To finance its future acquisition, exploration, development and operating costs, Bengal may 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"), 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 and have not been provided for in the financial statements nor do they include planned activities in excess of committed work programs. 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	750km^2 3D seismic	March 2, 2012[(2)]	$6.2
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$6.4
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$5.4
Onshore Australia – ATP 752	Drill 1 exploration well.	July 31, 2014	$1.5
Onshore Australia – ATP 732	Complete processing & interpretation of 2D and 3D seismic. Drill 1 exploration well.	March 31, 2015	$3.1
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP[(3)]	4 years after grant of ATP	$12.1

(1) Translated at December 31, 2011 exchange rate of US $1.00 = CAD $ 1.0197 and AUD $1.00 = CAD $1.0374

(2) Bengal has applied for an extension to the term of this offshore permit to Australia's Northern Territory Government Department of Resources to June 2, 2013.

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

Guarantees – India Permits

($000s) CAD	Nine Months Ended December 31, 2011	Year ended March 31, 2011
	12/31/11	03/31/11
CY-ONN-2005/1 – Onshore India – year 1	$ –	$ 485
CY-OSN-2005/1 – Onshore India – year 2	1,129	1,077
CY-OSN-2009/1 – Offshore India	155	152
Total Guarantees	**$ 1,284**	**$ 1,714**

These performance guarantees are based on a percentage of the capital commitments shown in the table above and are not reflected in the balance sheet as they are supported by Export Development Canada. These guarantees are cancelled when the Company completes the work required under the exploration period.

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 for are as follows:

Contractual Obligations ($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 1,274	$ 216	$ 742	$ 253	$ 63
Asset retirement obligations	163	–	47	12	104
Total contractual obligations	$ 1,437	$ 216	$ 789	$ 265	$ 167

RELATED PARTY TRANSACTIONS

The Company paid $40,050 in consulting fees to a former director of the Company and to a company controlled by the director. The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At December 31, 2011, the Company has an accounts payable balance of nil (March 31, 2011 - $41,328) payable to this former director. At the Company's Annual General Meeting on September 14, 2011, this director did not stand for re-election and has been appointed as Executive Vice President of the Company.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)	Quarter Ended							
	12/31/11	09/30/11	06/30/11	03/31/11	12/31/10	09/30/10	06/30/10	03/31/10 Note 2
Petroleum and natural gas sales	**$ 1,328**	$ 1,017	$ 1,319	$ 691	$ 430	$ 383	$ 349	$ 280
Cash flow from (used-in) operations	**(417)**	159	(1,371)	(746)	(681)	(455)	(570)	(493)
Per share Basic and diluted	**(0.01)**	0.00	(0.03)	(0.02)	(0.02)	(0.02)	(0.03)	(0.03)
Funds from (used in) operations[1]	**(206)**	(430)	7	(690)	(808)	(467)	(546)	(626)
Per share Basic and diluted	**0.00**	(0.01)	0.00	(0.02)	(0.03)	(0.02)	(0.03)	(0.03)
Net loss	**$ (477)**	$ (4,247)	$ (1,061)	$ (889)	$ (1,094)	$ (634)	$ (722)	$ (1,396)
Per share Basic and diluted	**(0.01)**	(0.08)	(0.02)	(0.03)	(0.04)	(0.04)	(0.04)	(0.08)
Additions to capital assets, net	**$ 4,175**	$ 2,407	$ 1,933	$ 1,879	$ 1,797	$ 174	$ 93	$ 553
Working capital	**28,798**	33,109	35,691	14,063	8,571	11,019	631	1,272
Total assets	**44,899**	45,696	51,072	25,829	17,799	17,538	6,693	7,413
Shares outstanding Basic and diluted	**52,110**	51,961	51,961	37,795	30,262	30,238	18,238	18,213
Operations								
Average daily production								
Natural gas (mcf/d)	**271**	196	249	348	327	366	381	377
Oil and NGLs (bbls/d)	**112**	97	110	59	39	41	31	12
Combined (boe/d)	**157**	130	152	117	94	102	94	75
Netback ($/boe)	**$ 49.89**	$ 51.42	$ 48.92	$ 31.31	$ 22.69	$ 13.33	$ 16.65	$ 18.67

(1) See "Non-GAAP Measurements" on page 2 of this MD&A.

(2) Fiscal 2010 comparatives were those derived under Previous GAAP and have not been restated to IFRS.

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. Oil sales increased in the quarter ended June 30, 2011 due to improvement in truck access to the Cuisinier 1 well which had been restricted due to flooding. In the three months ended September 30, 2011 Cuisinier 2 and 3 wells came on production. Oil sales in the most recent two quarters have been impacted from shut in production at Cuisinier 1 in order to test Cuisinier 2 and 3 and for all wells due to wet roads and waiting on trucking to resume. Gas volumes declined in the quarter ended September 30, 2011 due to a plant turnaround at the Oak B.C. property.

The net loss in the quarter ended March 31, 2010 includes an undeveloped property impairment charge of $0.5 million and the loss in the quarter ended June 30, 2011 includes an impairment charge of $0.7 million related to exploration and evaluation assets in Australia. The quarter ended September 30, 2011 includes impairment charges of $3.6 million for the AC/P 24 permit which was considered impaired after drilling and abandoning the Kingtree well offshore Australia in the Timor Sea.

FINANCIAL INSTRUMENTS

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

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not use derivative instruments at this time.

DISCLOSURE CONTROLS & PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

Disclosure Controls and Procedures

Disclosure controls and procedures 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

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 management has assessed the design and operating effectiveness of internal controls over financial reporting.

There were no changes in the Company's internal controls or weaknesses during the three months ended December 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 believes 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. 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 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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Significant accounting policies used by Bengal are disclosed in Note 2 to the June 30, 2011 unaudited consolidated interim financial statements. Preparing financial statements in accordance with IFRS requires management to make certain judgments and estimates. Changes to these judgments and estimates could have a material effect on the Company's financial statements and financial position.

Transition to International Financial Reporting Standards ("IFRS")

On April 1, 2011, Bengal adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes, using the transition date of April 1, 2010. The financial statements for the three months ended December 31, 2011, including required comparative information, have been prepared in accordance with IAS 34, Interim Financial Reporting. Note 2 to Bengal's unaudited consolidated interim financial statements as at and for the three months ended June 30, 2011 outlines the Company's IFRS accounting policies and Note 16 provides details of the Company's IFRS 1 elections and reconciliations between Canadian GAAP and IFRS.

The adoption of IFRS has not had an impact on the Company's operations, strategic decisions, key performance indicators and cash flow from operations. The Company noted a significant impact of IFRS conversion to its Property and Equipment. IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase.

NEW ACCOUNTING STANDARDS AND PRONOUNCEMENTS

The following describes new accounting pronouncements that have been issued but are not yet effective:

Amendments to IAS 1, Presentation of Financial Statements

In June 2011 the International Accounting Standards Board ("IASB") published amendments to IAS 1 *Presentation of Financial Statements: Presentation of Items of Other Comprehensive Income ("OCI"),* which are effective for annual periods beginning on or after July 1, 2012. The amendments require that an entity present separately the items of OCI that may be reclassified to profit and loss in the future from those that would never be reclassified to profit or loss. Consequently an entity that presents items of OCI before related tax effects will also have to allocate the aggregated tax amount between those categories.

The existing option to present the profit or loss and other comprehensive income in two statements has remained unchanged.

The Company intends to adopt the amendments in its financial statements for the annual period beginning April 1, 2013. The extent of the impact of adoption of the amendments has not yet been determined.

IFRS 9, Financial Instruments

IFRS 9 was issued in November 2009 and reflects the first phase of the IASB's work on the replacement of IAS 39 *Financial Instruments: Recognition and Measurement.* IFRS 9 applies to the classification and measurement of financial assets and liabilities as defined in IAS 39 and is effective for annual reporting periods beginning on or after January 1, 2015. The adoption of IFRS 9 is not expected to have a significant impact on the consolidated financial statements.

IFRS 10, Consolidated Financial Statements

IFRS 10 was issued in May 2011 and establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 replaces SIC-12 *Consolidation – Special Purpose Entities* and parts of IAS 27 *Consolidated and Separate Financial Statements* and is effective for annual periods beginning on or after January 1, 2013. Earlier adoption is permitted.

IFRS 11, Joint Arrangements

IFRS 11 was issued in May 2011 and focuses on the rights and obligations of a joint arrangement, rather than its legal form (as is currently the case). To address reporting inconsistencies, the standard requires a single method to account for interests in jointly controlled entities. IFRS 11 supersedes IAS 31 *Interests in Joint Ventures* and SIC-13 *Jointly Controlled Entities – Non-Monetary Contributions by Venturers* and is effective for annual periods beginning on or after January 1, 2013. Earlier adoption is permitted.

IFRS 12, Disclosure of Interests in Other Entities

IFRS 12 was issued in May 2011 and is a new and comprehensive standard and applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. Earlier adoption is permitted.

IFRS 13, Fair Value Measurements

IFRS 13 was issued in May 2011 and defines fair value, sets out a single IFRS framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 is to be applied for annual periods beginning on or after January 1, 2013. Earlier adoption is permitted.

The Company is currently evaluating the impact of adopting all of the newly issued and amended standards.

RISK FACTORS

There are a number of risk factors facing companies that participate in the International oil and gas industry. A complete list of risk factors is provided in Bengal's Annual Information Form dated July 12, 2011 filed on SEDAR at www.sedar.com.

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 100, 736 – 6th Avenue S.W., Calgary, Alberta T2P 3T7, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

Forward-looking Statements - *Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward-looking statements. These statements relate to future events or Bengal's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon.*

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

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Expectations that Bengal's future realized gas and oil prices will coincide with the B.C Station 2 and Brent daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cashflows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective;*
- *Commencement of exploration and development activities on Block CY-OSN-2009/1;*
- *Continuation of exploration, development activities on Permit AC/P 47 offshore Australia and whether the Company will be granted an extension on this permit past March 2, 2012 and whether a farm-out partner will be found on acceptable terms to the Company and if not, whether the Company will shoot seismic on this permit;*
- *Obtaining Native Title Agreement on ATP 934P in Australia and commencement of exploration activities;*
- *That seismic activities on ATP 732P will identify drillable prospects that will be drilled;*
- *That drilling of four wells will occur on ATP 752P in calendar Q2 of 2012 and seismic activity will follow drilling and that production from Cuisinier 1, 2 and 3 will continue as expected and that 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 ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continued stability of political, regulatory; tax and fiscal regimes in which the Company has operations.

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

- *Volatility in market prices for oil and natural gas;*
- *Liabilities inherent in oil and natural gas operations;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Unable to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Changes in income tax laws or changes to royalty and environmental regulations relating to the oil and gas industry;*
- *The risk that Bengal may not be successful in raising funds by an equity issue; and*
- *Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.*

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Bengal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. Additional information on these and other factors that could affect Bengal's operations and financial results are included in reports on file with Canadian securities authorities and may be accessed through the SEDAR website (www.sedar.com) and at Bengal's website (www.bengalenergy.ca).

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

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

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

DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Stephen N. Insbusch
Dr. Brian J. Moss

COMPENSATION AND GOVERNANCE COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Bryan C. Goudie, Chief Financial Officer
D. Garrett Wilson, Vice President, Engineering and Operations
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX:BNG

Condensed Interim Consolidated Financial Statements (unaudited)

Three and Nine Months Ended December 31, 2011 and 2010

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(Unaudited)

As at	Notes	Dec 31, 2011	March 31, 2011
ASSETS			
Current assets:			
Cash and cash equivalents	**4**	$ 29,116	$ 14,600
Restricted cash		135	1,227
Accounts receivable		1,978	817
Prepaid expenses and deposits		150	91
		31,379	16,735
Non-current assets:			
Petroleum and natural gas properties	**5**	3,546	2,030
Exploration and evaluation assets	**6**	9,974	7,064
		13,520	9,094
Total assets		$ 44,899	$ 25,829
LIABILITIES AND SHAREHOLDER'S EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		$ 2,581	$ 2,672
Non-current liabilities:			
Decommissioning liability	**7**	163	159
Shareholders' equity:			
Share capital	**8**	$ 86,246	$ 62,595
Warrants	**8**	–	705
Contributed surplus		5,436	4,189
Accumulated other comprehensive income		844	95
Deficit		(50,371)	(44,586)
		42,155	22,998
Total liabilities and shareholder's equity		$ 44,899	$ 25,829

See accompanying notes to the condensed consolidated financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

(Unaudited)

For the periods ended December 31,	Notes	Three months 2011	Three months 2010	Nine months 2011	Nine months 2010
Income					
Petroleum and natural gas revenue		$ 1,328	$ 430	$ 3,664	$ 1,162
Royalties		(121)	(46)	(337)	(114)
		1,207	384	3,327	1,048
Operating expenses					
General and administrative		853	915	2,641	2,154
Operating and transportation		486	189	1,324	588
Depletion and depreciation	**5**	126	94	327	265
Pre-licensing and E&E impairment	**6**	(251)	75	4,089	82
Exploration and evaluation expenses		293	–	293	–
Share-based compensation		169	254	686	441
		1,676	1,527	9,360	3,530
Operating loss		(469)	(1,143)	(6,033)	(2,482)
Other income (expenses)					
Finance income		174	55	482	55
Finance expenses		(3)	(7)	(49)	(26)
Foreign exchange gain (loss)		(179)	1	(185)	3
		(8)	49	248	32
Net Loss		(477)	(1,094)	(5,785)	(2,450)
Exchange differences on translation of foreign operations		520	51	749	99
Total comprehensive income (loss) for the period		$ 43	$ (1,043)	$ (5,036)	$ (2,351)
Earnings per share	**8**				
- Basic & Diluted		$ (0.01)	$ (0.04)	$ (0.11)	$ (0.08)
Weighted average number of shares outstanding (000s)	**8**				
- Basic & Diluted		52,088	30,257	51,282	22,515

See accompanying notes to the condensed consolidated financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Thousands of Canadian dollars)
(Unaudited)

	Share capital	Warrants	Contributed surplus	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2010	$ 43,460	$ 490	$ 3,890	$ -	$ (41,208)	$ 6,632
Net loss for the period	–	–	–	–	(2,450)	(2,450)
Comprehensive income for the period	–	–	–	99	–	99
Issue of share capital (Note 8)	10,992	160	–	–	84	11,236
Share based payments	–	–	267	–	–	267
Balance at December 31, 2010	**$ 54,452**	**$ 650**	**$ 4,157**	**$ 99**	**$ (43,574)**	**$ 15,784**
Shares outstanding	**30,261,813**					
Balance at April 1, 2011	$ 62,595	$ 705	$ 4,189	$ 95	$ (44,586)	$ 22,998
Net loss for the period	–	–	–	–	(5,785)	(5,785)
Comprehensive income for the period	–	–	–	749	–	749
Issue of share capital (Note 8)	23,651	–	(146)	–	–	23,505
Expiry of warrants	–	(705)	705	–	–	–
Share based payments	–	–	686	–	–	686
Balance at December 31, 2011	**$ 86,246**	**$ –**	**$ 5,436**	**$ 844**	**$ (50,371)**	**$ 42,155**
Shares outstanding	**52,110,127**					

See accompanying notes to the condensed consolidated financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of Canadian dollars)
(Unaudited)

For the periods ended December 31,	Notes	Three months 2011	Three months 2010	Nine months 2011	Nine months 2010
Operating activities					
Net loss		**$ (477)**	$ (1,094)	**$ (5,785)**	$ (2,450)
Non-cash items:					
Depletion and depreciation		**126**	94	**327**	265
Pre-licensing and E&E impairment		**(251)**	75	**4,089**	82
Accretion		**2**	5	**4**	7
Share-based compensation		**169**	254	**686**	441
Unrealized foreign exchange (gain) loss		**29**	(229)	**(145)**	(258)
Change in non-cash working capital	**11**	**(15)**	127	**(804)**	115
Net cash flow from (used in) operating activities		**(417)**	(768)	**(1,628)**	(1,798)
Investing activities					
Exploration and evaluation expenditures		**(4,174)**	(1,456)	**(8,166)**	(1,723)
Petroleum and natural gas properties		**(91)**	(129)	**(439)**	(129)
Change in restricted cash		**–**	(75)	**1,092**	375
Changes in investing working capital	**11**	**(1,608)**	1,004	**(229)**	988
Net cash flow from (used in) investing activities		**(5,873)**	(656)	**(7,742)**	(489)
Financing activities					
Proceeds from issuance of shares, net of issuance costs		**27**	(37)	**23,505**	10,978
Changes in financing working capital	**11**	**–**	(100)	**(82)**	(5)
Net cash flow from financing activities		**27**	(137)	**23,423**	10,973
Impact of foreign exchange on cash and cash equivalents		**132**	67	**463**	84
Net increase/(decrease) in cash equivalents		**$ (6,131)**	$ (1,494)	**$ 14,516**	$ 8,770
Cash and cash equivalents, beginning of period		**35,247**	11,319	**14,600**	1,055
Cash and cash equivalents, end of period		**$ 29,116**	$ 9,825	**$ 29,116**	$ 9,825

See accompanying notes to condensed consolidated financial statements.

BENGAL ENERGY LTD.

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

Three and nine months ended December 31, 2011 and 2010
(Tabular amounts are stated in thousands of Canadian dollars except share and per share amounts)
(Unaudited)

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.

Bengal's registered office is located at 1000, 736 – 6th Avenue SW, Calgary, Alberta.

2. BASIS OF PREPARATION

Statement of compliance

These condensed consolidated interim financial statements as at December 31, 2011, including 2010 comparative periods, comprise a period of the Company's first annual consolidated financial statements to be issued under IFRS at March 31, 2012 and have been prepared in accordance with IAS 34 "Interim Financial Reporting". As a result, IFRS 1 "First-time Adoption of Internal Financial Reporting Standards" has been applied. The condensed consolidated interim financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the reported consolidated financial position, financial performance and cash flows of the Company is provided in Note 15. That note includes reconciliations as at December 31, 2010 and for the three and nine month periods ended December 31, 2010. For reconciliations to IFRS at the date of transition, being April 1, 2010, and March 31, 2011, refer to Note 16 of the condensed consolidated interim financial statement for the three months ended June 30, 2011.

For the Company's detailed accounting policies, refer to Note 2 of the condensed consolidated interim financial statements for the three months ended June 30, 2011.

Basis of measurement

These condensed consolidated interim financial statements have been prepared on a historical cost basis. The comparative figures presented in the consolidated financial statements are in accordance with IFRS and have not been audited. The Company's presentation currency is Canadian dollars ($).

Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from these estimates.

Following are the significant estimates and judgments and the key sources of estimation uncertainty that the Company believes could have the most significant impact on the reported results and financial position:

Reserves

The estimate of petroleum and natural gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's development and production assets has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing and timing of future expenditures, all of which are subject to significant judgment and interpretation.

Decommissioning provisions

Amounts recorded for decommissioning obligations require the use of management's best estimates of future decommissioning expenditures, expected timing of expenditures and future inflation rates. The estimates are based on internal and third party information and calculations and are subject to change over time and may have a material impact on profit and loss or financial position.

Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

3. SIGNIFICANT ACCOUNTING POLICIES

The interim condensed consolidated financial statements have been prepared following the same accounting policies and methods of computation as the interim condensed consolidated financial statements as at June 30, 2011. The significant accounting policies are described in note 2 of the June 30, 2011 interim condensed consolidated financial statements.

The impacts of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at December 31, 2010 and for the three and nine months ended December 31, 2010, are presented in note 15 herein.

4. CASH AND CASH EQUIVALENTS

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

As at ($000s)	December 31, 2011	March 31, 2011
Cash and bank balances	**$ 4,795**	$ 1,880
Short-term deposits	**24,321**	12,720
	$ 29,116	$ 14,600

5. PETROLEUM AND NATURAL GAS PROPERTIES

	Petroleum and Natural Gas Properties $000s	**Corporate Assets $000s**	**Total $000s**
Cost:			
Balance at April 1, 2010	$ 21,041	$ 581	$ 21,622
Additions	492	-	492
Exchange adjustments	(563)	-	(563)
Balance at March 31, 2011	20,970	581	21,551
Additions	439	–	439
Transfers from E&E assets	1,336	–	1,336
Exchange adjustments	645	–	645
Balance at December 31, 2011	$ 23,390	$ 581	$ 23,971

	Petroleum and Natural Gas Properties	Corporate Assets	Total
	$000s	$ 000s	$000s
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2010	$ 19,315	$ 385	$ 19,700
Depletion and depreciation charge for the period	286	51	337
Exchange adjustments	(516)	-	(516)
Balance at March 31, 2011	19,085	436	19,521
Depletion and depreciation charge for the period	298	29	327
Exchange adjustments	577	–	577
Balance at December 31, 2011	$ 19,960	$ 465	$ 20,425
Net carrying value			
At April 1, 2010	$ 1,726	$ 196	$ 1,922
At March 31, 2011	$ 1,885	$ 145	$ 2,030
At December 31, 2011	$ 3,430	$ 116	$ 3,546

The depletion expense calculation for the three months ended December 31, 2011 included $847,000 (December 31, 2010 - $948,000) for estimated future development costs associated with proved and probable reserves in Canada and Australia.

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

	Exploration and Evaluation Expenditures
Balance at April 1, 2010	$ 3,553
Additions	3,338
Exchange adjustments	173
Balance at March 31, 2011	$ 7,064
Additions	8,166
E&E impairment loss	(4,089)
Transfer to petroleum and natural gas properties	(1,336)
Exchange adjustments	169
Balance at December 31, 2011	$ 9,974

Exploration and evaluation assets consist of the Company's exploration projects in Australia and India which are pending the determination of technical feasibility and commercial viability. Costs primarily consist of acquisition costs, geological & geophysical work, seismic and drilling costs.

The Kingtree well, located on the AC/P 24 permit off the north coast of Australia in the Timor Sea, was drilled in October of 2011 to evaluate a potential oil target. No commercial hydrocarbons were encountered and the well has been plugged and abandoned. Due to the result of the Kingtree well, an assessment was made of all costs attributable to the AC/P24 permit on which the Kingtree well was drilled. An impairment loss of $3.1 million, equal to all costs associated with the AC/P24 permit, has been recorded in the nine months ended December 31, 2011.

In addition to the impairment loss on the AC/P24 permit, impairment losses of $1.0 million have been recorded in the nine months ended December 31, 2011 for final costs of an abandoned well drilled in 2008.

The Cuisinier 2 and 3 wells were deemed by management to be technically feasible and commercially viable and in September, 2011 costs attributed to the wells were transferred from E&E assets to Development and Production (“D&P”) assets within petroleum and natural gas properties.

The offshore Australia AC/P 47 permit is scheduled to expire on March 2, 2012. The Company has requested an extension from Australia’s Northern Territory Government of Resources to June 2, 2013. If the extension is not obtained, $0.8 million of exploration and evaluation assets will be impaired in the fourth quarter.

7. DECOMMISSIONING AND RESTORATION LIABILITY

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

Changes to decommissioning and restoration obligations were as follows:

	December 31, 2011	March 31, 2011
Decommissioning liabilities, beginning of period	**$ 159**	$ 115
Revision	**–**	(4)
Additions	**–**	43
Accretion	**4**	5
Decommissioning liabilities, end of period	**$ 163**	$ 159

The Company’s decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation adjusted undiscounted amount of cash flow required to settle its decommissioning and restoration costs at December 31, 2011 is approximately $213,000 (March 31, 2013 – $204,000) which will be incurred between 2012 and 2027. An inflation factor of 2.0% and a discount rate of 4.0% have been applied to the decommissioning liability at December 31, 2011.

8. SHARE CAPITAL

(a) Authorized:

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

(b) Issued:

The following provides a continuity of share capital:

($000s)	Number of Shares		Amount
Balance at April 1, 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)
At March 31, 2011	37,794,549	$	62,595
Shares issued for cash	14,166,800		25,500
Issued on exercise of stock options	148,778		173
Share issue costs	–		(2,022)
At December 31, 2011	52,110,127	$	86,246

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 $2,022,000, were $23,478,000.

In October 2011, 75,000 stock options were exercised for $0.36 per share whereby 75,000 common shares were issued for proceeds of $27,000.

In October 2011, 100,000 stock options with an exercise price of $0.36 and 125,000 stock options with an exercise price of $1.26 were exercised based on a cashless exercise whereby 73,778 common shares were issued based on a market share price of $1.28 per share on the date of exercise.

Stock based compensation of $146,000 has been moved from contributed surplus to equity as a result of the option exercises.

(c) Stock-based compensation - warrants:

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

($000s)	Number of Warrants		Amount
Balance April 1, 2010	**940,000**	**$**	**490**
Stock-based compensation expense	-		215
Balance March 31, 2011	**940,000**	**$**	**705**
Transfer to contributed surplus on warrant expiry	**(940,000)**		**(705)**
Balance December 31, 2011	**-**	**$**	**-**

These warrants expired on August 13, 2011.

(d) Share-based compensation – stock options:

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

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

Bengal has incorporated an estimated forfeiture rate of 6.4% for stock options that are not expected to vest.

A summary of stock option activity is presented below:

	Options		Weighted Average Exercise Price
Outstanding at April 1, 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**
Granted	1,150,000		1.26
Forfeited	(208,335)		1.35
Expired	(417,000)		2.84
Exercised	(300,000)		0.74
Outstanding at December 31, 2011	**2,395,332**	**$**	**1.15**
Exercisable at December 31, 2011	1,505,336	$	1.06

	Options Outstanding			Options Exercisable	
Option Price (1)	Number Outstanding	Exercise Price (2)	Remaining Life (3)	Number Exercisable	Exercise Price (2)
$ 0.36–1.25	801,666	$ 0.75	3.5	534,998	$ 0.56
$ 1.26–2.25	1,593,666	$ 1.34	2.9	970,338	$ 1.34
Total	**2,395,332**	**$ 1.15**	**3.1**	**1,505,336**	**$ 1.06**

(1) Range of option exercise prices

(2) Weighted average exercise price of options

(3) Weighted average remaining contractual life of options in years

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

For the Period Ended	December 31, 2011	March 31, 2011	April 1, 2010
Assumptions:			
Risk free interest rate (%)	2.0%	2.0%	2.0%
Expected life (years)	5 yr	3 yr	3 yr
Expected volatility (%)	69%	72%	122%
Vesting period (years)	2 yr	2 yr	2 yr
Weighted average fair value of options granted	$0.76	$0.70	$0.91

The fair value of stock options granted during the nine months and quarter ended December 31, 2011 was $871,000 and nil respectively.

(e) Earnings (loss) per share:

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

At December 31, 2011, there were 2,395,334 (December 31, 2010 – 2,175,667) options considered anti-dilutive and at December 31, 2011 there were nil warrants (December 31, 2010 – 940,000) considered anti-dilutive.

9. FINANCIAL RISK MANAGEMENT

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

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

(a) Fair value of financial instruments:

Financial instruments comprise cash and cash equivalents, 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 and receivables from petroleum and natural gas marketers. As at December 31, 2011, Bengal's receivables consisted of $1.4 million (March 31, 2011 - $0.6 million) from joint venture partners and $0.6 million (March 31, 2011 - $0.2 million) of other trade receivables.

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

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

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

At December, 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 does not have an allowance for doubtful accounts as at December 31, 2011 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the three or nine months ended December 31, 2011.

Cash and cash equivalents, when held, consist of cash bank balances and guaranteed investment certificates redeemable at any time. Bengal manages the credit exposure related to guaranteed investments by selecting counterparties based on credit ratings and monitors all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset backed commercial paper.

(c) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due. Bengal's financial liabilities consist of accounts payable and accrued liabilities and amounted to $2.6 million at December 31, 2011 (March 31, 2011 - $2.7 million). Bengal had $29.1 million in cash (March 31, 2011 - $14.6 million), $0.1 million in restricted cash (March 31, 2011 - $1.2 million) and a net working capital surplus of $28.8 million at December 31, 2011 (March 31, 2011 - $14.1 million).

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

(d) Market risk:

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk. The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used to reduce exposure to these risks.

Foreign Currency Risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives Canadian dollars for sales in Canada, U.S. dollars for Australian oil sales and incurs expenditures in Australian, Canadian and U.S. currencies. Having sales and expenditures denominated in three currencies spreads the impact of individual currency fluctuations.

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

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

As at December 31, 2011 ($000s)	Total	CAD	AUD	U.S.D
			CAD $ Equivalent	
Cash and short-term deposits	29,116	19,222	4,620	5,274
Restricted cash	135	135	–	–
Accounts receivable	1,978	229	467	1,282
Accounts payable and accrued liabilities	(2,581)	(804)	(1,777)	–
Balance sheet exposure	28,648	18,782	3,310	6,556

A 5% strengthening or (weakening) of the CAD as compared to the AUD and USD would have increased or (decreased) net comprehensive loss by $680,000 respectively.

Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of a change in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. Australian oil prices are based on the Daily Brent reference price, which trades at a premium to WTI. There were no financial instruments in place to manage commodity prices during the three or nine months ended December 31, 2011.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk on its cash and cash equivalents that have a floating interest rate. The Company is receiving 1.31% to 1.47% interest on its CAD guaranteed investment certificates at a Canadian chartered bank, 4.55% to 5.6% on AUD term deposits in Australia and 0.75% to 1.75% on its USD term deposits at ICICI Canada. A 1.0% decrease in interest rates would have resulted in a $252,000 increase to net loss and cash outflow from operating activities in the nine months ended December 31, 2011 and a 1.0% increase in interest rates would decrease net loss and cash flow used in operating activities by $252,000 over the same period. The Company had no interest rate swaps or hedges at December 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

Nine months ended December 31 ($000s)		2011		2010
Accounts receivable	$	(965)	$	(143)
Prepaid expenses and deposits		(59)		13
Accounts payable and accrued liabilities		(91)		1,228
Total	$	(1,115)	$	1,098
Relating to:				
Operating	$	(804)	$	115
Financing		(82)		(5)
Investing		(229)		988
Total	$	(1,115)	$	1,098

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

The following represents the cash interest received in each period.

Nine months ended December 31 ($000s)		2011		2010
Cash interest received	$	378	$	19

12. COMMITMENTS AND CONTINGENCIES

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. The costs of these activities are based on minimum work budgets included in bid documents and have not been provided for in the financial statements nor do they include planned activities in excess of committed work programs. 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(2)	$6.2
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$6.4
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$5.4
Onshore Australia – ATP 752	Drill 1 exploration well.	July 31, 2014	$1.5
Onshore Australia – ATP 732	Complete processing & interpretation of 2D and 3D seismic. Drill 1 exploration well.	March 31, 2015	$3.1
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP(3)	4 years after grant of ATP	$12.1

(1) Translated at December 31, 2011 exchange rate of US $1.00 = CAD $ 1.0197 and AUD $1.00 = CAD $1.0374

(2) Bengal has applied for an extension to the term of this offshore permit to Australia's Northern Territory Government Department of Resources to June 2, 2013.

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

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

($000s)		
Fiscal 2011 – January 2011 to March 2011 (old lease - sublease)	$	32
Fiscal 2012 – April 2012 to Mar 2012 (new lease – head lease)		245
	$	277

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

13. RELATED PARTY TRANSACTIONS

The Company paid $40,050 in consulting fees to a former director of the Company and to a company controlled by the director. The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At December 31, 2011, the Company has an accounts payable balance of nil (March 31, 2011 - $41,328) payable to this former director. At the Company's Annual General Meeting on September 14, 2011, this director did not stand for re-election and has been appointed as Executive Vice President of the Company.

14. SEGMENTED INFORMATION

As at December 31, 2011, the Company has three reportable operating segments being the Australian, Canadian and New Cost Centres' oil and gas operations. New Cost Centres are considered to be in the pre-production stage and includes India and Ireland.

Revenue reported below represents revenue generated from external customers. There were not inter-segment sales in any of the reported periods.

The accounting policies of the reportable segments are the same as the group's accounting policies. Segment profit represents the profit earned by each segment without allocation of central administration costs and directors' salaries, finance costs and income tax expense. This is the measure reported to the chief operating decision maker for the purposes of resource allocation and assessment of segment performance.

For the nine months ended Dec 31, 2011 ($000)	Australia	Canada	Other[1]	Total
Revenue	$ 3,361	$ 303	$ –	$ 3,664
Net loss	(2,922)	(2,125)	(738)	(5,785)
Petroleum and natural gas property expenditures	447	–	–	447
Exploration and evaluation expenditures	7,412	–	754	8,166
Impairment losses	(4,089)	–	–	(4,089)
December 31, 2011 ($000)				
Petroleum and natural gas properties				
Cost	19,146	4,374	451	23,971
Accumulated depletion, depreciation and accretion	(16,334)	(3,640)	(451)	(20,425)
Net book value	2,812	734	–	3,546
Exploration and evaluation assets	12,503	–	1,560	14,063
Accumulated impairment losses	(4,089)	–	–	(4,089)
Net book value	$ 8,414	$ –	$ 1,560	$ 9,974

(1) Other is new cost centres considered to be in the pre-production stage and includes India and Ireland.

For the nine months ended Dec 31, 2010 ($000)	Australia	Canada	Other[1]	Total
Revenue	$ 749	$ 413	$ –	$ 1,162
Net loss	(425)	(1,865)	(160)	(2,450)
Petroleum and natural gas property expenditures	$ –	$ 29	$ –	$ 29
Exploration and evaluation expenditures	1,905	–	130	2,035
As at March 31, 2011 ($000)				
Petroleum and natural gas properties				
Cost	16,733	4,367	451	21,551
Accumulated depletion, depreciation and accretion	(15,551)	(3,519)	(451)	(19,521)
Net book value	1,182	848	–	2,030
Exploration and evaluation cost	$ 6,315	$ –	$ 749	$ 7,064

(1) Other is new cost centres considered to be in the pre-production stage and includes India and Ireland.

15. TRANSITION TO IFRS

As stated in Note 2, these are the Company's third IFRS condensed consolidated interim financial statements prepared in accordance with IFRS. The impact that the transition from Canadian GAAP to IFRS has had on the Company's financial position, financial performance and cash flow is set out in this note.

The significant accounting policies described in Note 2 to the interim consolidated financial statements for the three months ended June 30, 2011 have been applied in the preparation of these financial statements for the quarter ended December 31, 2011, as well as in the preparation of the comparative information presented for the three and nine months ended December 31, 2010 except where certain IFRS 1 exemptions have been applied as described below.

Exemptions Applied

IFRS 1 *First-time Adoption of International Financial Reporting Standards* allows first-time adopters certain exemptions from the general requirement to retrospectively apply IFRS that were effective as at April 1, 2010. The Company has applied the following exemptions:

- IFRS 3 *Business Combinations* has not been applied to acquisitions of subsidiaries that occurred before April 1, 2010.
- IFRS 2 *Share-based Payment* has not been applied to equity instruments which vested before the Company's transition date to IFRS.
- The deemed cost of exploration and evaluation assets are the amount determined under Canadian GAAP. For assets in the development or production phases the deemed cost is the amount determined for the cost centre under Canadian GAAP, allocated to the cost centre's underlying assets pro rata using reserve volumes as of April 1, 2010.
- IAS 21 The Company set cumulative translation differences for its foreign operations to zero at transition.
- IAS 37 The Company measured asset retirement obligations ("ARO") in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* and recognized directly into retained earnings the difference between that amount and the carrying amount of ARO under Canadian GAAP.

IFRS 1 also requires that an entity's estimates under IFRS at the date of transition be consistent with estimates made under its Canadian GAAP for the same date, unless there is objective evidence that those estimates were made in error. The Company's IFRS estimates at April 1, 2010 are consistent with the estimates made under Canadian GAAP for that same date.

Reconciliations from Canadian GAAP to IFRS

An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's consolidated statements of financial position, statements of operations and comprehensive loss as at December 31, 2010 and for the three and nine months ended December 31, 2010 is set out in the following reconciliations and in the notes that accompany the reconciliations. Certain amounts on the statements of financial position and the statements of operations and comprehensive loss have been reclassified to conform to the presentation adopted under IFRS.

Reconciliation of Assets, Liabilities and Equity as reported under Canadian GAAP to IFRS

		December 31, 2010		
	Note	**CDN GAAP**	**Adj**	**IFRS**
		($)	($)	($)
ASSETS				
Current assets				
Cash & cash equivalents		9,825	1	9,826
Restricted cash		135	1	136
Accounts receivable		416	–	416
Prepaid expenses & deposits	**A**	90	(3)	87
		10,466	(1)	10,465
Non-current assets				
Petroleum and natural gas properties	**A & B**	7,145	(5,087)	2,058
Exploration & evaluation assets	**A & B**	–	5,276	5,276
Total assets		17,611	188	17,799
LIABILITIES & SHAREHOLDER'S EQUITY				
Current liabilities				
Accounts payable & accrued liabilities		1,894	–	1,894
		1,894	–	1,894
Non-current liabilities				
Decommissioning liability	**C**	99	22	121
		99	22	121
Total liabilities		1,993	22	2,015
Shareholder's equity				
Share capital		54,452	–	54,452
Warrants		650	–	650
Contributed surplus	**D**	4,194	(37)	4,157
Accumulated other comprehensive income		–	99	99
Deficit	**A to D**	(43,678)	104	(43,574)
		15,618	166	15,784
Total liabilities & shareholder's equity		$ 17,611	$ 188	$ 17,799

Reconciliation of Net Earnings for the Period Ended **December 31, 2010**.		Three Months			Nine Months		
		CDN GAAP	Adj	IFRS	CDN GAAP	Adj	IFRS
		$000s	$000s	$000s	$000s	$000s	$000s
Petroleum and natural gas		430	–	430	1,162	–	1,162
Royalties		(46)	–	(46)	(114)	–	(114)
Revenue		384	–	384	1,048	–	1,048
Operating expenses							
General and administrative	**	917	–	917	2,175	(21)	2,154
Operating and transportation		189	–	189	588	–	588
Depletion and depreciation	B	133	(39)	94	352	(87)	265
Pre-licensing and impairment	B	–	75	75	–	82	82
Share-based compensation	D	282	(28)	254	497	(56)	441
Total expenses		1,521	8	1,529	3,612	(82)	3,530
Operating loss		(1,137)	(8)	(1,145)	(2,564)	82	(2,482)
Other income (expenses)							
Interest income		55	–	55	55	–	55
Finance and accretion		–	(5)	(5)	–	(26)	(26)
Foreign exchange gain (loss)		51	(50)	1	43	(40)	3
		106	(55)	51	98	(66)	32
Net Loss		(1,031)	(63)	(1,094)	(2,466)	16	(2,450)
Exchange differences on translation of foreign operations	A	-	51	51	-	99	99
Total comprehensive loss for the period		(1,031)	(12)	(1,043)	(2,466)	115	(2,351)

** For the nine months ended December, 2010 letter of credit charges of $17,000 (three months ended December 31, 2011 $nil) have been reclassified as finance expenses.

A. Changes in functional currency

Under IAS 21 - The Effects of Changes in Foreign Exchange Rates, the method of determining functional currency takes into account a broader range of factors than under GAAP. This has resulted in the functional currency of Avery Resources Australia (Pty) Ltd. changing from the Canadian dollar to the Australian dollar and the functional currency of Bengal Energy International Inc. (India) from the Canadian dollar to the U.S. dollar.

As such the value of a number of balance sheet accounts have been revalued with the resulting impact for the nine months ended December 31, 2010 is as follows: increase in cash and restricted cash of $2,000; decrease in prepaid expenses and deposits of $3,000 and an increase in D&P and E&E assets of $81,000 and $109,000 respectively offset by a decrease to deficit of $189,000.

Differences arising from the translation of financial statements that are prepared under a currency other than the presentation currency of the consolidated financial statements are recognized as a separate component of equity. The Company has made use of the exemption in IFRS 1 that such translation differences were deemed zero at the date of transition.

For the three and nine month periods ended December 31, 2010, IFRS transition differences resulted in an exchange gain on translation of foreign operations of $51,000 and $39,000, respectively.

B. Exploration and evaluation assets ("E&E") (Note the changes in this section must be added to the changes identified in Note A in order to reconcile to the table on page 16)

IFRS 1 – Deemed Cost. The Company applied the IFRS 1 exemption whereby the value of its opening plant, property and equipment at April 1, 2010 was deemed to be equal to the net book value as determined under Canadian GAAP and the corresponding Cash Generating Units ("CGU's") were tested for impairment. The Company chose to allocate its costs to its CGU's based on proved plus probable reserve volumes.

Under Canadian GAAP the Company followed the full cost method of accounting for oil and gas properties whereby all costs associated with the exploration for and the development of oil and gas reserves were capitalized in country-based cost centers. Under IFRS, pre-exploration costs are recognized in the statement of operations as incurred. Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been determined are capitalized as E&E assets. Once an exploration area has been deemed to be technically feasible and commercially viable, E&E costs are reclassified to development and production assets, a separate category of property and equipment.

The following reclassifications were made from property, plant and equipment under Canadian GAAP:

For the nine months ended December 31, 2010, a reduction in D&P assets of $5,248,000 with a corresponding increase in E&E assets of $5,167,000 and $81,000 charged to the statement of operations relating to pre-licensing costs.

Depletion and depreciation:

Upon transition to IFRS, the Company adopted a policy of depleting and depreciating oil and natural gas interests on a unit of production basis over proved plus probable reserves taking into account the future development costs required to bring those reserves into production. The depletion and depreciation policy under Canadian GAAP was based on unit of production over proved reserves.

There was no impact of this difference on adoption of IFRS at April 1, 2010 as a result of the IFRS 1 exemption taken. For the nine months ended December 31, 2010 the use of proved plus probable reserves resulted in a decrease to depletion of $80,000 (three months ending December 31, 2010 $36,000) with a corresponding increase to D&P assets.

C. Decommissioning liabilities

Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of the decommissioning, discounted to their net present value upon initial recognition. Under Canadian GAAP, asset retirement obligations were discounted at a credit adjusted risk free rate of seven to ten percent. Under IFRS, the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted; therefore the provision is discounted at a risk free rate of four percent. Decommissioning obligations are also required to be re-measured based on changes in estimates including discount rates.

At December 31, 2010, using a risk free rate of 4%, the Company increased its decommissioning obligations by $22,000 from the previous GAAP amount offset by an increase to deficit of $22,000.

The change in accretion expense under IFRS compared with GAAP was not significant. Under IFRS, accretion of the discount is included in finance expenses whereas under GAAP it is included in depletion and depreciation.

D. Share-based payment transactions

The Company issues certain share-based awards in the form of stock options that vest one-third on the grant date and one-third on each of the next two anniversaries of the grant date. Under IFRS, the fair value of each instalment of the award is considered a separate grant based on the vesting period with the fair value of each instalment determined separately and recognized as compensation expense over the term of its respective vesting period ("graded vesting"). Accordingly, this will result in the amounts of each grant being recognized in income at a faster rate than under GAAP.

Under GAAP, the Company accounts for forfeited stock options in the period in which the forfeiture occurred. Under IFRS, the Company estimated forfeitures at the grant date with revised estimates reflected in each subsequent reporting period. Accordingly, this will result in the amounts of each grant being recognized in income at a slower rate than under GAAP partially offsetting the impact of the graded vesting discussed above.

IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1") provides an elective exemption which does not require first-time adopters to apply IFRS 2 Share-based Payment to equity instruments that were granted on or before November 7, 2002, or equity instruments that were granted subsequent to November 7, 2002 and vested before the later of the date of transition to IFRS and January 1, 2005. The Company has used this election.

As a result of this election an increase of $19,000 has been made to contributed surplus with an offsetting increase in the deficit at April 1, 2010.

Share based compensation decreased by $56,000 for the nine months ended December 31, 2010 ($28,000 for the three months ended December 31, 2010). An increase of $46,000 in share based compensation expense is offset by a decrease in warrant amortization of $102,000 for the nine months ended December 31, 2010. For the three months ended December 31, 2010, share based compensation increased by $6,000 offset by a reduction in warrant amortization of $34,000. These adjustments were offset by a $56,000 decrease to contributed surplus at December 31, 2010 ($28,000 at September 30, 2010 and $11,000 at June 30, 2010).

E. Cash flow statement

The transition from Canadian GAAP to IFRS did not have a material impact on the consolidated statement of cash flows.

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DISCLOSURE COMMITTEE

All Directors are members of the Committee

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