Bengal
ENERGY LTD.

International exploration & production

Management's Discussion & Analysis

Three Months Ended June 30, 2011 and 2010

MANAGEMENT'S DISCUSSION AND ANALYSIS – September 12, 2011

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Bengal Energy Ltd. ("Bengal" or the "Company") should be read in conjunction with the unaudited interim Consolidated Financial Statements and accompanying notes for the three months ended June 30, 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 second fiscal quarter of 2012 with a very strong balance sheet showing approximately $37.6 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 US $25 premium to WTI.

AUSTRALIA – Onshore

In the Cooper Basin of Australia, the Cuisinier light oil discovery and follow up development wells are contributing steady growth in net operating income which has now surpassed general and administrative costs in the quarter for the first time. Field level analysis of the economics of the Cuisinier project shows finding and development costs for the prior year (including future development costs) of $10.59 per barrel based on the change in the Cuisinier property proved and probable reserves from March 31, 2010 to March 31, 2011, as evaluated by the Company's independent reserves evaluators. Field level operating netbacks for Cuisinier averaged $50.50 per barrel over the year ended March 31, 2011. This allows the calculation of a very satisfactory Recycle Ratio of 4.8 for the project (Finiding & Development costs divided by field netback - $50.50/$10.49). Field level operating netbacks for the current quarter increased by $21.02 to $71.52 per barrel.

Additional drilling and 3D seismic are in the planning stages for the latter portion of this year and next.

Also in the Cooper Basin, formal grant of Bengal's operated permit ATP 732P has been received and exploration efforts have commenced with 400 kilometers of 2D and 50 square kilometers of 3D to be shot during September and October. Bengal has already defined numerous leads and prospects on the permit and a drilling campaign is planned for early 2012.

Australia – Offshore – Timor Sea

Bengal and its partner will drill the Kingtree well on a well defined, fault bound structure identified from 3D seismic on offshore permit AC/P24 in the Timor Sea of North West Australia. The exploration drilling location lies northeast and on trend with the formerly productive Challis-Cassini oil field (60MM bbls cumulative oil with peak production of 43,000 bopd). The intent will be to vertically drill Kingtree 1 using a semi-submersible rig to a depth of 1,500 meters from 110 meters water depth. As is normal practice in the Timor Sea, the plans are to evaluate the reservoir with logs and wireline testing and then plug and abandon the test well until such time as a full development plan can be derived. The prospect sits as a separate structure approximately 15 kilometres southeast from Bengal's Katandra oil discovery. Success with Kingtree 1 could in some circumstances enable joint development of Katandra. The operator expects to spud Kingtree 1 in mid October 2011. The well is scheduled to take 18 days to drill and evaluate and

Bengal has a 10% working interest in the project.Elsewhere in the Timor Sea, Bengal has acquired two regional seismic lines across its 100% operated permit AC/P47. Previously announced independent resource estimates indicate this could be a very material exploration permit. The new 2D seismic was acquired to assist in the design of and planning for a 750 km2 3D program that is anticipated late in 2011. Bengal continues its efforts to seek either a JV partner or potential farmee to assist the Company with accelerating both the seismic program and seeing nearer term drilling activity on permit AC/P47.

INDIA – Offshore

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

INDIA – Onshore

On Bengal's 30% working interest, 233,000 gross acre Production Sharing Agreement CY-ONN-2005/1, work is well underway on the first year work program. Reprocessing of existing seismic data has been completed and a contractor has been engaged for the acquisition of 700 km2 of 3D seismic data. The acquisition program will take place after the monsoon season in December and early in 2012. Airborne magnetometry work will also commence in 2011. The increased 3D seismic acquisition is intended to help the joint venture to accelerate the drilling of exploration wells on the permit (3 exploration wells were planned for the minimum work program) which, subject to the seismic results, could be drilled in late 2012 at the earliest.

SUMMARY

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

$000s except per share, volumes and netback amounts	Three Months Ended 06/30/11	06/30/10	03/31/11
Revenue			
Natural gas	**$ 92**	$ 125	$ 125
Natural gas liquids	**16**	21	17
Oil	**1,211**	202	549
Total	**1,319**	349	691
Royalties	**121**	28	67
% of revenue	**9.2**	8.1	9.7
Operating & transportation	**522**	179	295
Netback[1]	**676**	142	328
Cash flow used in operations:	**(1,371)**	(570)	(746)
Per share ($) (basic & diluted)	**(0.03)**	(0.03)	(0.02)
Funds from (used in) operations[2]:	**7**	(546)	(690)
Per share ($) (basic & diluted)	**0.00**	(0.03)	(0.02)
Net (loss):	**(1,061)**	(722)	(889)
Per share ($) (basic & diluted)	**(0.02)**	(0.04)	(0.03)
Capital expenditures	**$ 1,933**	$ 93	$ 1,879
Volumes			
Natural gas (mcf/d)	**249**	381	348
Natural gas liquids (boe/d)	**2**	4	3
Oil (bbl/d)	**108**	27	56
Total (boe/d @ 6:1)	**152**	94	117
Netback[1] ($/boe)			
Revenue	**$ 95.46**	$ 40.92	$ 65.49
Royalties	**8.77**	3.31	6.38
Operating & transportation	**37.77**	20.96	27.97
Total	**$ 48.92**	$ 16.65	$ 31.13

(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 financial statements and data presented herein were prepared in accordance with International Accounting Standard 34 ("IAS 34"), Interim Financial Reporting, as issued by the International Accounting Standards Board. Previously, the Company prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles referred to herein as previous GAAP.

For the purpose of calculating unit costs, natural gas volumes have been converted to barrels of oil equivalent ("boe") using a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of oil. The following abbreviations are used in this MDA: boe/d means barrels of oil equivalent per day; bbl/d means barrels per day and mcf/d means thousand cubic feet of natural gas per day.

This MD&A and accompanying financial statements and notes are for the three-month period ended June 30, 2011. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from April 1, 2011 through June 30, 2011. The term "prior year's quarter" is used throughout the MD&A for comparative purposes and refers to the period from April 1, 2010 through June 30, 2010. The term "prior quarter" refers to the three months ended March 31, 2011.

The fiscal year for the Company is the 12-month period ended March 31, 2012. The terms "fiscal 2012," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2011 through March 31, 2012. The terms "previous year," "prior year" and "fiscal 2011" are used in the MD&A for comparative purposes and refer to the period from April 1, 2010 through March 31, 2011.

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		
$000s	**06/30/11**	06/30/10	03/31/11
Cash flow used in operations	**(1,371)**	(570)	**(746)**
Changes in non-cash working capital	**1,378**	24	**56**
Funds from (used in) operations	**7**	(546)	**(690)**

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 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;*
- *That drilling of the Kingtree well will occur on AC/P 24 offshore Australia;*
- *Obtaining Native Title Agreement on ATP 934P in Australia and commencement of exploration activities;*
- *That seismic activities will occur on ATP 732P and that the seismic will be followed by drilling;*
- *That there will be additional drilling and seismic activity on ATP 752P and that Cuisinier wells 2 and 3 will commence production and that production from these two wells and Cuisinier 1 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.

RESULTS OF OPERATONS

Production

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

Production	Three Months Ended		
	06/30/11	**06/30/10**	**03/31/11**
Natural gas (mcf/d)	**249**	381	348
NGLs (boe/d)	**2**	4	3
Oil (bbls/d)	**108**	27	56
Total (boe/d)	**152**	94	117

For the three months ended June 30, 2011, total oil, natural gas and natural gas liquids (NGLs) production averaged 152 boe/d, an increase of 62% from the 94 boe/d produced in the prior year comparable quarter.

The increase in production is due to having Cuisinier 1 on production for a full quarter in the current year (the well commenced production in May of 2010). Also, prior to the current quarter, the Cuisinier well experienced approximately 50% downtime due to restricted truck access due to flooding. In the current quarter the well experienced production uptime of greater than 90%.

The Cuisinier 2 and 3 wells were production tested in July 2011 and brought on stream at the end of August. Initial production estimates from the Operator prior to start-up are in excess of 250 barrels per day for Cuisinier 2 and 3 in total (63 b/d net). Bengal will release actual production numbers after the wells demonstrate sustained production rates.

Gas and NGL volumes declined in the current quarter due to the shut-down of the McMahon Facility at the Company's Oak British Columbia property for maintenance for most of June.

The increase in production volumes in the current quarter compared to the quarter ended March 31, 2011 is due to the improved production uptime for the Cuisinier 1 well.

Pricing

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

Prices and Marketing	Three Months Ended		
	06/30/11	**06/30/10**	**03/31/11**
Average Benchmark Prices			
AECO 30 day firm ($/mcf)	**$ 3.74**	$ 3.77	$ 3.77
Dated Brent oil ($US/bbl)	**116.01**	81.34	105.32
Number of CAD$ for 1 AUD$	**1.03**	0.91	0.99
Number of CAD$ for 1 USD$	**0.97**	1.03	0.99
WTI oil ($US/bbl)	**$ 102.55**	$ 77.99	$ 94.17
Bengal's Realized Price ($ CAD)			
Natural gas ($/mcf)	**$ 4.07**	$ 3.60	$ 3.96
Oil ($/bbl)	**123.27**	83.66	109.06
NGLs ($/bbl)	**72.22**	65.83	60.40
Total ($/boe)	**$ 95.46**	$ 40.92	$ 65.49

Bengal's total realized price on a boe basis increased for the three months ended June 30, 2011 compared to the prior year quarter by $54.54 due to higher oil and gas prices. Current quarter prices increased by $29.97 compared to the prior quarter due to higher oil prices and an increased proportion of sales from higher priced oil volumes Vs gas in the total sales mix.

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 $4.65/bbl premium to Brent since January 1, 2011.

Oak, British Columbia gas sales are marketed by the operator and the price received is based on the reference price at British Columbia's Station 2 plus $0.03 per mcf.

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

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 ($000s)			**Three Months Ended**
	06/30/11	**06/30/10**	**03/31/11**
Natural gas	**$ 92**	$ 125	$ 125
NGLs	**16**	21	17
Oil	**1,211**	203	549
Total	**$ 1,319**	$ 349	$ 691

Petroleum and natural gas sales for the first quarter of the 2012 fiscal year were 278% or $970,000 higher than the prior year comparable period. Increased oil volumes contributed $616,000 to the increase in revenues while $389,000 of the increase is due to higher oil prices. These changes were offset by minor changes in gas volumes and prices.

Revenue in the current quarter increased 91% or $628,000, from the fourth quarter of fiscal 2011. The increase is due to higher oil production from the Cuisinier well which had improved production uptime as trucking access is no longer restricted due to flooding.

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 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, British Columbia gas wells.

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

Royalties by Type ($000s)			**Three Months Ended**
	06/30/10	**06/30/10**	**03/31/11**
Canada Crown	**$ 6**	$ 3	$ 12
Canada gross overriding	**6**	6	8
Australian Government	**109**	19	47
Total	**$ 121**	$ 28	$ 67
$/boe	**8.77**	3.31	6.38
% of revenue	**9.2**	8.1	9.7

Royalties by Commodity	Three Months Ended		
	06/30/11	**06/30/10**	**03/31/11**
Natural gas			
$000s	**$ 9**	$ 5	$ 16
$/mcf	**0.38**	0.15	0.50
% of revenue	**9.4**	4.3	12.7
Oil			
$000s	**$ 109**	$ 19	$ 47
$/bbl	**11.09**	7.81	9.43
% of revenue	**9.0**	9.3	8.6
NGLs			
$000s	**$ 3**	$ 4	$ 4
$/bbl	**15.55**	12.10	13.92
% of revenue	**21.5**	18.4	23.1

For the first quarter of the 2012 fiscal year, royalties were 332%, or $93,000 higher than the previous comparable period due to higher production volumes and product prices. Royalties as a percentage of revenue and per boe increased as there was a $14,000 Crown Royalty credit included in the prior year figures.

Royalties increased on a per boe in the current quarter compared to the three months ended March 31, 2011 due an increase in the portion of oil volumes compared to total volumes as oil has a higher per boe royalty charge than gas.

Operating & Transportation Expenses

Operating and transportation expenses in the first quarter of the 2012 fiscal year increased $343,000 to $522,000 compared to $179,000 in the prior year comparable quarter. The increase is due to higher oil volumes in Australia and a facility turnaround at the Company's Oak B.C property. Operating costs increased by $16.81 per boe in the current quarter compared the prior year quarter. The increase is due to higher cost Cuisinier oil volumes which are trucked and Oak costs were higher while production was lower due to facility turnaround.

Operating and transportation costs increased by $227,000 ($9.80 per boe) in the current quarter compared to the prior quarter due to a facility turnaround at the Oak B.C property.

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 kilometres of pipelines. The oil is then sent through a pipeline to Port Bonython, South Australia.

Operating Expenses ($000s)	Three Months Ended		
	06/30/11	**06/30/10**	**03/31/11**
Australia			
Operating	**$ 226**	$ 50	$ 119
Transportation	**173**	38	87
	399	88	206
Canada – Operating costs	**123**	91	89
Total	**$ 522**	$ 179	$ 295
Australia			
Operating - $/boe	**23.07**	20.37	23.70
Transportation - $/boe	**17.58**	15.73	17.21
Canada - $/boe	**30.67**	14.93	16.14
Total ($boe)	**$ 37.77**	$ 20.96	$ 27.97

General and Administration (G&A) Expenses

In the first quarter of fiscal 2012, G&A expenses increased by 14%, or $92,000 over the prior fiscal year's quarter. Expenses in the current quarter are higher due to recruitment agency costs incurred to hire senior technical personnel.

G&A expenses decreased by 31%, or $340,000 in the current quarter compared to the prior quarter. The decrease in expenses is due to the prior quarter including consulting costs for preparation of resource reports on certain of the Company's properties.

General and Administrative Expenses ($000s)	Three Months Ended		
	06/30/11	06/30/10	03/31/11
G&A	**$ 762**	$ 670	$ 1,102

Stock-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 stock-based compensation ("SBC") expense of $277,000 for the current quarter compared to $93,000 in the comparable prior year's period. The increase is due to new option grants in the current quarter a third of which vested immediately compared to the prior year period when a number of employee options had become fully vested.

Stock-based compensation in the three months ended June 30, 2011 increased from the March 31, 2011 quarter due to for the same reasons noted above.

Stock Based Compensation ($000s)	Three Months Ended		
	06/30/10	06/30/10	03/31/11
SBC - options	**$ 277**	$ 73	$ 79
SBC - warrants	**-**	20	11
Stock-based compensation	**$ 277**	$ 93	$ 90

In June 2011, 750,000 stock options were granted to employees, directors and 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.

During the current quarter 172,000 options expired with an average exercise price of $3.74 per option.

In the period from June 30, 2011 up to the date of this report, 150,000 options were forfeited and 200,000 stock options were granted at an exercise price of $1.05. These options vest one-third immediately and one-third on each of the next two anniversaries of the grant date and expire five years from the grant date.

Stock-based compensation related to outstanding warrants is NIL for the three months ended June 30, 2011 as the warrants are fully amortized (June 30, 2010 - $20,000). The warrants expired on August 13, 2011.

Depletion and Depreciation

Depletion and depreciation increased by $17,000 for the three months ended June 30, 2011 over the comparable prior year's period. The decrease in Canada is due to lower gas volumes due to a facility turnaround at 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.

DD&A Expenses ($000s)	Three Months Ended		
	06/30/11	**06/30/10**	**03/31/11**
DD&A – Australia	**$ 63**	$ 28	$ 34
DD&A – Canada	**34**	51	44
Total	**$ 97**	$ 79	$ 78
$/boe – Australia	**6.34**	11.61	6.74
$/boe – Canada	**8.53**	7.42	7.90
$/boe – Total	**$ 7.02**	$ 9.32	$ 7.35

At June 30, 2011 the company reported a $702,000 impairment loss against exploration and evaluation assets. The impairment relates to drilling costs charged by the operator in the current quarter 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 June 30, 2011 funds from operations increased to $7,000 or $0.00 per basic and diluted share compared to funds used in operations of $546,000 or $0.03 per basic and diluted share in the prior comparable period. The increase in funds from operations is due to higher net operating income primarily as a result the increased production uptime for the Cuisinier 1 well and higher oil prices.

For the three months ended June 30, 2011 cash flow used in operations increased to $1,371,000 or $0.03 per basic and diluted share compared to cash flow used in operations of $570,000 or $0.03 per basic and diluted share in the prior comparable period. The increase in funds used is mainly due to higher accounts receivable for oil sales.

The loss for the three months ended June 30, 2011 was $1,061,000 or $0.02 per basic and diluted share compared to a loss of $722,000 or $0.04 per basic and diluted share in the prior fiscal year. The higher loss is due to an Exploration and Evaluation impairment charges of $0.7 million partially offset by higher net operating income in the current quarter.

CAPITAL EXPENDITURES

Drilling expenditures of $702,000 in the current quarter related to late charges from the operator for the Hudson well which was drilled in 2008. These costs were written off as an impairment charge in the current quarter as the well was plugged and abandoned in 2008. Completion costs of $1,049,000 in the current quarter are to complete and equip Cuisinier 2, 3 and Barta North 1 and to tie-in Cuisinier 2 and 3.

Subsequent to the end of the current quarter, the operator of ATP 752P (Wompi Block) plugged and abandoned the Sampdoria well. This well was fully funded by the operator as part of their farm-in work and therefore Bengal incurred no cost to drill this well.

Capital Expenditures ($000s)	Three Months Ended		
	06/30/11	**06/30/10**	**03/31/11**
Geological and geophysical	**$ -**	$ -	$ 991
Geological and geophysical	**182**	93	251
Drilling	**702**	-	637
Completions	**1,049**	-	-
Total capital expenditures	**1,933**	93	1,879
Exploration & evaluation expenditures	**$ 1,937**	$ 93	$ 1,859
Development & production expenditures	**(4)**	-	20
Total net expenditures	**$ 1,937**	$ 93	$ 1,879

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. On September 12, 2011 there are 51,961,349 common shares issued and outstanding.

In April 2011, the Company issued 14,166,800 common shares at a price of $1.80 per share. Proceeds of the offering, net of share issue costs of $2,022,000, were $23,478,000.

At September 12, 2011, there were 2,798,667 employee stock options outstanding with an average exercise price of $1.19 per share. Of these, 1,716,337 are exercisable at an average price of $1.12 per share. These options expire between 2011 and 2016 with an average remaining life of 2.9 years.

Trading History			**Three Months Ended**
	06/30/11	**06/30/10**	**03/31/11**
High	**$ 2.06**	$ 1,72	$ 2.33
Low	**1.03**	1.02	1.22
Close	**$ 1.15**	$ 1.22	$ 1.95
Volume (000s)	**4,714**	711	14,266
Shares outstanding			
Basic and diluted	**51,961**	18,238	37,795
Weighted average shares outstanding			
Basic and diluted	**49,782**	18,225	35,532

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2011 the Company had working capital of $35.7 million, including cash and short term deposits of $37.6 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. The Company's current working capital position may not provide it with sufficient capital resources to meet its minimum work obligations for all exploration periods under the various permits the Company holds and for general corporate purposes. To finance its future acquisition, exploration, development and operating costs, Bengal most likely will require financing from external sources, including issuance of new shares or executing working interest farmout arrangements. The Company is actively marketing the opportunity for interested parties to farm in to its operated oil and gas permits offshore India and Australia but there is no assurance these efforts will be successful. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to Bengal.

CONTRACTUAL ARRANGEMENTS

Pursuant to current production sharing contracts ("PSC"), 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. 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	$6.2
Offshore Australia – AC/P24	Drill 1 exploration well	February 7, 2012	$1.5
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$6.6
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$3.0
Onshore Australia – ATP 752	Drill 1 development well. Tie-in and connect 3 wells.	July 31, 2014	$2.6
Onshore Australia – ATP 732	Shoot 456km^2 of 2D and 50km^2 of 3D seismic. Drill 1 exploration well.	March 31, 2015	$7.2
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP[2]	4 years after grant of ATP	$12.1

(1) Translated at June 30, 2011 exchange rate of US $1.00 = CAD $ 0.9765 and AUD $1.00 = CAD $1.0346

(2) Currently negotiating Native Title Agreement with the Wongkumara People of Queensland. The Native Title Agreement is then submitted to the Government of Queensland for approval and granting of the Authority to Prospect ("ATP"). Work program consists of 500km of 2D seismic and up to seven wells.

Guarantees – India Permits

($000s) CAD	Quarter ended June 30, 2011	Year ended March 31, 2011
	03/31/11	03/31/10
CY-ONN-2005/1 – Onshore India – year 1	$ -	$ 485
CY-OSN-2005/1 – Onshore India – year 2	1,077	1,077
CY-OSN-2009/1 – Offshore India	152	152
Total Guarantees	**$ 1,299**	**$ 1,714**

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

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

Other

At March 31, 2011, the contractual obligations for which the Company is responsible for are as follows:

Contractual Obligations ($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 95	$ 95	$ -	$ -	$ -
Asset retirement obligations	161	33	14	12	102
Total contractual obligations	$ 256	$ 128	$ 14	$ 12	$ 102

RELATED PARTY TRANSACTIONS

The Company paid $33,000 in consulting fees and travel costs to a director of the Company and to a company controlled by a director. The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At June 30, 2011, the Company has an accounts payable balance of $12,600 (March 31, 2011 - $41,328) payable to this director.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)	Quarter Ended							
	06/30/11	03/31/11	12/31/10	09/30/10	06/30/10	03/31/10 Note 2	12/31/09 Note 2	09/30/09 Note 2
Petroleum and natural gas sales	**$ 1,319**	$ 691	$ 430	$ 383	$ 349	$ 280	$ 413	$ 505
Cash flow used-in operations	**(1,371)**	(746)	(681)	(455)	(570)	(493)	(264)	(263)
Per share Basic and diluted	**(0.03)**	(0.02)	(0.02)	(0.02)	(0.03)	(0.03)	(0.01)	(0.01)
Funds from (used in) operations[1]	**7**	(690)	(808)	(467)	(546)	(626)	(347)	(295)
Per share Basic and diluted	**0.00**	(0.02)	(0.03)	(0.02)	(0.03)	(0.03)	(0.02)	(0.02)
Net loss	**$ (1.061)**	$ (889)	$ (1,094)	$ (634)	$ (722)	$ (1,396)	$ (885)	$ (1,848)
Per share Basic and diluted	**(0.02)**	(0.03)	(0.04)	(0.04)	(0.04)	(0.08)	(0.05)	(0.10)
Additions to capital assets, net	**$ 1,933**	$ 1,879	$ 1,797	$ 174	$ 93	$ 553	$ 1,120	$ (426)
Working capital	**35,691**	14,063	8,571	11,019	631	1,272	2,501	3,970
Total assets	**51,072**	25,829	17,799	17,538	6,693	7,413	8,928	9,159
Shares outstanding Basic and diluted	**51,961**	37,795	30,262	30,238	18,238	18,213	18,213	18,213
Operations								
Average daily production								
Natural gas (mcf/d)	**249**	348	327	366	381	377	422	787
Oil and NGLs (bbls/d)	**110**	59	39	41	31	12	30	53
Combined (boe/d)	**152**	117	94	102	94	75	100	184
Netback ($/boe)	**$ 48.92**	$ 31.31	$ 22.69	$ 13.33	$ 16.65	$ 18.67	$ 21.39	$ 11.77

(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.

From September 30, 2009 to March 31, 2010 volumes and revenues had been on a declining trend due to natural reservoir declines and lower commodity prices and the sale of the Kaybob gas wells in September, 2009. Beginning in the quarter ended June 30, 2010 and continuing through to the current quarter, oil volumes started increasing due to commencement of production from the Cuisinier well in the Cooper Basin of Australia in May 2010. Oil production 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 quarter ended September 30, 2009 the net loss was increased by a loss on the disposal of oil and gas assets of $943,000. The net loss in the quarter ended March 31, 2010 includes an undeveloped property impairment charge of $0.5 million and the loss in the quarter ended June 30, 2011 includes an impairment charge of $702,000 related to exploration and evaluation assets in Australia.

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 June 30, 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, access and documentation. The Company expects that some deficiencies will continue into the future; and

- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advice on complex financial accounting issues and for tax planning, tax provision and compilation of corporate tax returns.

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by Bengal are disclosed in Note 3 to the audited Consolidated Financial Statements for the years ended June 30, 2011 and 2010. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstance may result in actual results or changes to estimated amounts that differ materially from current estimates. A detailed discussion of the critical accounting policies and practices of the Company helps assess the likelihood of materially different results being reported is disclosed in the March 31, 2011 Annual Management Discussion and Analysis.

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 June 30, 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:

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, 2013. 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 are 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.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Valiant Trust Corporation • Calgary, Canada

INVESTOR RELATIONS

Bryan Mills Iradesso • Calgary, Canada

DIRECTORS

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

GOVERNANCE AND DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Bryan 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

Bengal
ENERGY LTD.

Condensed Interim Consolidated Financial Statements (unaudited)

For the period ended June 30, 2011

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at	Notes	June 30, 2011	March 31, 2011	April 1, 2010
ASSETS				
Current assets:				
Cash and cash equivalents	**4**	$ 37,648	$ 14,600	$ 1,055
Restricted cash	**5**	135	1,227	510
Accounts receivable		2,845	817	273
Prepaid expenses and deposits		70	91	100
		40,698	16,735	1,938
Non-current assets:				
Petroleum and natural gas properties	**6**	1,961	2,030	1,922
Exploration and evaluation assets	**7**	8,413	7,064	3,553
		10,374	9,094	5,475
Total assets		$ 51,072	$ 25,829	$ 7,413
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities		$ 5,007	$ 2,672	$666
Non-current liabilities:				
Decommissioning liability	**8**	161	159	115
Shareholders' equity:				
Share capital	**9**	$ 86,073	$ 62,595	$ 43,460
Warrants	**9**	705	705	490
Contributed surplus		4,468	4,189	3,890
Accumulated other comprehensive income		305	95	-
Deficit		(45,647)	(44,586)	(41,208)
		45,904	22,998	6,632
Total liabilities and shareholder's equity		$ 51,072	$ 25,829	$ 7,413

Subsequent event (note 9d)

See accompanying notes to the condensed consolidated financial statements.

On behalf of the Board:

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

For the three months ended June 30,	Notes	2011	2010
Income			
Petroleum and natural gas revenue		$ 1,319	$ 349
Royalties		(121)	(28)
		1,198	321
Operating expenses			
General and administrative		762	670
Operating and transportation		522	179
Depletion and depreciation	**6**	97	79
Pre-licensing and impairment	**7**	702	2
Stock-based compensation		277	93
		2,360	1,023
Operating loss		(1,162)	(702)
Other income (expenses)			
Finance income		140	-
Finance expenses		(44)	(18)
Foreign exchange gain (loss)		5	(2)
		101	(20)
Net Loss		(1,061)	(722)
Exchange differences on translation of foreign operations		210	(48)
Total comprehensive loss for the period		$ (851)	$ (770)
Earnings per share	**9**		
- Basic & Diluted		$ (0.02)	$ (0.04)
Weighted average number of shares outstanding (000s)	**9**		
- Basic & Diluted		49,782	18,225

See accompanying notes to the condensed consolidated financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

	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	-	-	-	-	(722)	(722)
Comprehensive loss for the period	-	-	-	(48)	-	(48)
Issue of share capital (Note 9)	8	54	-	-	(5)	57
Share based payments	-	-	31	-	-	31
Balance at June 30, 2010	**$ 43,468**	**$ 544**	**$ 3,921**	**$ (48)**	**$(41,935)**	**$ 5,950**
Shares outstanding	**18,237,783**					
Balance at April 1, 2011	$ 62,595	$ 705	$ 4,189	$ 95	$ (44,586)	$ 22,998
Net loss for the period	-	-	-	-	(1,061)	(1,061)
Comprehensive loss for the period	-	-	-	210	-	210
Issue of share capital (Note 9)	23,478	-	-	-	-	23,478
Share based payments	-	-	279	-	-	279
Balance at June 30, 2011	**$ 86,073**	**$ 705**	**$ 4,468**	**$ 305**	**$ (45,647)**	**$ 45,904**
Shares outstanding	**51,961,349**					

See accompanying notes to the condensed consolidated financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of Canadian dollars)

For the three months ended June 30,	Notes		2011		2010
Operating activities					
Net loss before income tax		$	(1,061)	$	(722)
Non-cash items:					
Depletion and depreciation			97		79
Exploration and evaluation impairment			702		2
Accretion			2		2
Share-based compensation			277		93
Unrealized foreign exchange loss			(10)		-
Change in non-cash working capital	**12**		(1,378)		(24)
Net cash flow from (used in) operating activities			(1,371)		(570)
Investing activities					
Exploration and evaluation expenditures			(1,937)		(93)
Petroleum and natural gas properties			4		-
Change in restricted cash			1,092		350
Changes in investing working capital	**12**		1,788		(97)
Net cash flow from (used in) investing activities			947		160
Financing activities					
Proceeds from issuance of shares, net of issuance costs			23,478		-
Changes in financing working capital	**12**		(82)		(5)
Net cash flow from (used in) financing activities			23,396		(5)
Impact of foreign exchange on cash and cash equivalents			76		(3)
Net Decrease in cash and short-term deposits		$	23,048	$	(418)
Cash and cash equivalents, beginning of period			14,600		1,055
Cash and cash equivalents, end of period		**$**	37,648	**$**	**637**

See accompanying notes to condensed consolidated financial statements.

BENGAL ENERGY LTD.

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

First quarter report for the three months ended June 30, 2011
(Tabular amounts are stated in thousands of Canadian dollars except share and per share amounts)

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1. INCORPORATION:

Bengal Energy Ltd (the "Company" or "Bengal") is incorporated under the laws of the Province of Alberta and is involved in the exploration for and development of oil and gas reserves in Australia, India and Canada.

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

2. SIGNIFICANT ACCOUNTING POLICES:

The financial statements have been prepared in accordance with International Accounting Standard 34 *Interim Financial Reporting* ("IAS 34") as issued by the International Accounting Standards Board ("IASB"). These are the Company's first set of financial statements prepared under International Financial Reporting Standards ("IFRS") for part of the period covered by the first IFRS annual financial statements and IFRS 1 First Time Adoption of International Financial Reporting Standards has been applied. They do not include all of the information required for full annual financial statements; previously the financial statements were presented under Canadian generally accepted accounting principles ("GAAP"). As a result reconciliation has been prepared between GAAP and IFRS to illustrate the impact adoption of IFRS has on the financial statements of the company (note 16).

The financial statements have been prepared in accordance with IFRS on a historical cost basis, except for certain financial instruments that have been measured at fair value.

(a) Basis of consolidation:

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

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

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

(b) Cash and cash equivalents

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

(c) Decommissioning and restoration liabilities:

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

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

(d) Oil and natural gas exploration and development expenditures

Exploration and evaluation costs ("E&E" assets")

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

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

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

Impairment

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and when they are reclassified to Development and Production ("D&P") assets. For the purpose of impairment testing, E&E assets are grouped by concession or field with other E&E and D&P assets belonging to the same concession or field. The impairment loss will be calculated as the excess of the carrying value over recoverable amount of the E&E impairment grouping and any resulting impairment loss is recognized in profit and loss. Recoverable amount is generally determined by reference to the value in use or fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

(e) Petroleum and natural gas properties

Carrying value

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

Depreciation

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

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

Impairment

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

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

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

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

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

(f) Financial assets and liabilities

Financial assets and liabilities are classified as either financial assets or liabilities at fair value through profit and loss, loans and receivables, held to maturity investments, available for sale financial assets, or interest bearing loans and borrowings, as appropriate. Financial assets and liabilities are recognized initially at fair value.

Financial assets and liabilities at fair value through profit or loss

Financial assets and liabilities at fair value through profit or loss include financial assets and liabilities held for trading and financial assets and liabilities designated upon initial recognition at fair value through profit or loss. Financial assets and liabilities are classified as held for trading if they are acquired for the purpose of selling in the near term. Derivatives are also classified as held for trading financial assets and liabilities held for trading. Gains or losses on assets and liabilities held for trading are recognized in profit and loss. The Company has no financial instruments classified as fair value through profit or loss.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, loans and receivables are subsequently carried at amortized cost using the effective interest method less any allowance for impairment. Amortized cost is calculated taking into account any discount or premium on acquisition and includes fees that are an integral part of the effective interest rate and transaction costs. The Company has classified cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued liabilities as loans and receivables.

Fair value

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

Share capital

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

(g) Foreign currency translation:

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

(h) Share-based compensation:

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

(i) Revenue recognition:

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

(j) Joint operations:

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

(k) Earnings (loss) per share:

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

(l) Income taxes:

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

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

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

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

(m) Determination of fair value:

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

1) Property, plant and equipment are recognized at fair value in a business combination. The fair value of property, plant and equipment is the estimated amount for which the property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions, being 10% for fiscal 2012 (2011 – 10%).

   The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

2) The fair value of cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At June 30, 2011 and March 31, 2011 the fair value of these balances approximated their carrying value due to their short term to maturity.

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

3. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of the Company's consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the balance sheet date and reported amounts of revenues and expenses during the reporting period. Estimates and judgments are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ materially from these estimates. In particular, significant estimation uncertainty exists in the accounting of oil and gas properties, impairment and provision for decommissioning costs.

In the process of applying Bengal's accounting policies, management made the following judgments, apart from those involving estimates, which have the most significant effect on the amounts recognized in the consolidated financial statements:

Reserves estimation

The capitalized costs of proved oil and gas properties are amortized to expense on a unit-of-production basis at a rate calculated by reference to proved plus probable reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook, and incorporating the estimated future cost of developing and extracting those reserves. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors, future development and extraction costs and future oil and gas prices. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated processing facilities and other capital costs.

Proved reserves are those reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, with existing technology. Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, or regulatory uncertainties preclude such reserves being classified as proved. Probable reserves are attributed to known accumulations, and claim a 50% confidence level of recovery. Possible reserves are attributed to known accumulations which have a less likely chance of being recovered than probable reserves. This term is often used for reserves which are claimed to have at least a 10% certainty of being produced.

Impairment of non-financial assets

The recoverable amounts of Bengal's cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions. It is reasonably possible that the oil and gas price and other assumptions may change in the future, which may impact the Company's recoverable amount calculations and will therefore require a material adjustment to the carrying value of petroleum and natural gas properties. The company monitors internal and external indicators of impairment relating to its exploration and evaluation assets and petroleum and natural gas properties.

Decommissioning and restoration costs

Decommissioning and restoration costs will be incurred by the Company at the end of the operating lives of Bengal's petroleum and natural gas properties. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements and the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditures can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future results.

Stock-based compensation

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the grant date. Estimating fair value requires the determination of the most appropriate valuation model for a grant of equity instruments, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk-free interest rate, volatility and dividend yield and making assumptions about them. The assumptions and model used are disclosed in note 9.

4. CASH AND CASH EQUIVALENTS

For the purposes of the statement of cash flows, cash and cash equivalents include cash on hand and in banks and investments with an original maturity date of three months or less, net of outstanding bank overdrafts. Cash and short-term deposits at the end of the reporting period as shown in the statement of cash flows can be reconciled to the related items in the statement of financial position as follows:

As At ($000s)	**June 30, 2011**	**March 31, 2011**	**April 1, 2010**
Cash and bank balances	$ 1,211	$ 1,880	$ 1,055
Short-term deposits	36,437	12,720	-
	$ 37,648	**$** 14,600	**$ 1,**055

5. RESTRICTED CASH

As at June 30, 2011, the Company had a $ 0.1 million (March 31, 2011 - $1.2 million; April 1, 2010 - $0.5 million) in restricted cash. The amount at June 30, 2011 is to secure corporate Visa cards. In prior periods the Company had restricted cash to secure performance guarantees issued to the Government of India regarding Bengal's exploration permits in India. In June, 2011, the Company negotiated an Account Performance Security Guarantee with the Canadian Federal Government, through Export Development Canada (EDC) in the amount of $1.3 million. EDC has undertaken to guarantee the obligations of the Company to the Government of India up to the amount of the Security Guarantee.

6. PETROLEUM AND NATURAL GAS PROPERTIES

	Petroleum and Natural Gas Properties	Corporate Assets	Total
	$000s	**$000s**	**$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	(4)	-	(4)
Exchange adjustments	546	-	546
Balance at June 30, 2011	$ 21,512	$ 581	$ 22,093

	Oil and 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	87	10	97
Exchange adjustments	514	-	514
Balance at June 30, 2011	$19,686	$ 446	$ 20,132
Net carrying value			
At April 1, 2010	$ 1,726	$ 196	$ 1,922
At March 31, 2011	$ 1,885	$ 145	$ 2,030
At June 30, 2011	$ 1,826	$ 135	$ 1,961

The depletion expense calculation for the three months ended June 30, 2011 included $1,987,000 (2010 - $948,000) for estimated future development costs associated with proved and probable reserves in Canada and Australia.

7. EXPLORATION AND EVALUATION 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		1,937
E&E impairment loss		(702)
Exchange adjustments		114
Balance at June 30, 2011	$	8,413

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 drilling costs until the drilling of the well is complete and results have been evaluated. The E&E impairment loss in the current quarter relates to costs of an abandoned well.

8. 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:

		June 30, 2011		**March 31, 2011**		**April 1, 2010**
Decommissioning liabilities, beginning of period	**$**	159	**$**	115	$	179
Revision		-		(4)		8
Additions		-		43		-
Liabilities settled		-		-		(21)
Liabilities disposed		-		-		(63)
Accretion		2		5		12
Decommissioning liabilities, end of period	$	161	**$**	159	$	115

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 June 30, 2011 is approximately $213,000 (March 31, 2011 – $204,000) which will be incurred between 2012 and 2026. An inflation factor of 2.0% and a discount rate of 4% have been applied to the decommissioning liability at June 30, 2011.

9. 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
Share issue costs	-	(2,022)
At June 30, 2011	51,961,349	$86,073

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.

(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 and June 30, 2011	**940,000**	**$**	**705**

These warrants expired on August 13, 2011.

(d) Stock-based compensation – stock options:

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

Bengal accounts for its stock-based compensation plan using the fair value method. Under this method, each grant results in three installments. The fair value of the first installment is charged to operations and loss immediately. The remaining two installments are charged to operations and loss over their respective vesting period of two and three 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 5% 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	750,000	1.32
Expired	(172,000)	3.74
Outstanding at June 30, 2011	**2,748,667**	**$1.21**
Exercisable at June 30, 2011	1,649,672	$1.12

Subsequent to quarter end 200,000 stock options were granted at an exercise price of $1.05. These options vest one-third immediately and one-third on each of the next two anniversaries of the grant date and expire five years from the grant date.

	Options Outstanding			Options Exercisable	
Option Price (1)	Number Outstanding	Exercise Price (2)	Remaining Life (3)	Number Exercisable	Exercise Price (2)
$ 0.36	576,667	$ 0.36	2.7	576,667	$ 0.36
$ 1.26–2.25	2,052,000	$ 1.34	3.1	953,005	$ 1.33
$ 2.26–3.25	120,000	$ 3.15	0.4	120,000	$ 3.15
Total	**2,748,667**	**$ 1.21**	**2.9**	**1,649,672**	**$ 1.12**

(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	June 30, 2011	March 31, 2011	April 1, 2010
Assumptions:			
Risk free interest rate (%)	4.0%	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	$0.80	$0.70	$0.91

The fair value of stock options granted during the quarter ended June 30, 2011 was $597,000.

(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 last two years and therefore any addition to basic shares outstanding is anti-dilutive.

At June 30, 2011, there were 2,749,000 (June 30, 2010 – 1,709,000) options considered anti-dilutive and at June 30, 2011 there were also 940,000 warrants (June 30, 2010 – 940,000) considered anti-dilutive.

10. 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 June 30, 2011, Bengal's receivables consisted of $2.5 million (March 31, 2011 - $0.6 million) from joint venture partners and $0.3 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 propety.

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 June 30, 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 June 30, 2011 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the quarters ended June 30, 2011 or March 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 $5.0 million at June 30, 2011 (March 31, 2011 - $2.7 million). Bengal had $37.6 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 $35.7 million at June 30, 2011 (March 31, 2011 - $14.1million).

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 June 30, 2011 ($000s)				
	Total	**CAD**	**AUD**	**U.S.D**
			CAD $ Equivalent	
Cash and short-term deposits	37,648	32,574	3,694	1,380
Restricted cash	135	135	-	-
Accounts receivable	2,845	280	1,051	1,514
Accounts payable and accrued liabilities	(5,007)	(316)	(4,691)	-
Balance sheet exposure	35,621	32,673	54	2,894

A 5 % strengthening or (weakening) of the CAD as compared to the AUD or USD would have increased or (decreased) net loss by $347,000 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 quarter ended June 30, 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 1.3% interest on its guaranteed investment certificates in Canada and 4.55% on term deposits in Australia. A 1.0% decrease in interest rates would have resulted in an $87,000 increase to net loss and cash flow used in operating activities in the quarter ended June 30, 2011 and a 1.0% increase in interest rates would decrease net loss and cash flow used in operating activities by $87,000 over the same period. The Company had no interest rate swaps or hedges at June 30, 2011.

11. 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.

12. CHANGES IN NON-CASH WORKING CAPITAL

Quarters Ended ($000s)	**June 30, 2011**	**June 30, 2010**
Accounts receivable	$ (2,027)	$ (78)
Prepaid expenses and deposits	20	(10)
Accounts payable and accrued liabilities	2,335	(38)
Total	$ 328	$ (126)
Relating to:		
Operating	$ (1,378)	$ (24)
Financing	(82)	(97)
Investing	1,788	(5)
Total	$ 328	$ (126)

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

Quarters Ended ($000s)	**June 30, 2011**	**June 30, 2010**
Cash interest received	$ 7	$ -
Total	$ 7	$ -

13. 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. 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	$6.2
Offshore Australia – AC/P24	Drill 1 exploration well	February 7, 2012	$1.5
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$6.6
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$3.0
Onshore Australia – ATP 752	Drill 1 development well. Tie-in and connect 3 wells.	July 31, 2014	$2.6
Onshore Australia – ATP 732	Shoot 456km^2 of 2D and 50km^2 of 3D seismic. Drill 1 exploration well.	March 31, 2015	$7.2
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP[2]	4 years after grant of ATP	$12.1

(1) Translated at June 30, 2011 exchange rate of US $1.00 = CAD $ 0.9765 and AUD $1.00 = CAD $1.0346

(2) Currently negotiating Native Title Agreement with the Wongkumara People of Queensland. The Native Title Agreement is then submitted to the Government of Queensland for approval and granting of the Authority to Prospect (“ATP”). Work program consists of 500km of 2D seismic and up to seven wells.

Bengal is pursuing joint venture or farm-out arrangements to finance its exploration commitments under some of these licenses.

At June 30, 2011 the Company had the following lease commitment for office space in Canada:

($000s)	
Fiscal 2011 – July 2011 to March 2012	$ 95

14. RELATED PARTY TRANSACTIONS

The Company paid $33,000 in consulting fees and travel costs to a director of the Company and to a company controlled by a director. The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At June 30, 2011, the Company has an accounts payable balance of $12,600 (March 31, 2011 - $41,328) payable to this director.

15. SEGMENTED INFORMATION

As at June 30, 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 described in Note 3. 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 Three Months Ended June 30, 2011	**Australia**	**Canada**	**Other[1]**	**Total**
Revenue	$ 1,211	$ 108	$ -	$ 1,319
Net loss	(259)	(734)	(68)	(1,061)
Petroleum and natural gas property expenditures	(4)		-	(4)
Exploration and evaluation expenditures	1,836		101	1,937
Impairment losses	(702)	-	-	(702)
As at June 30, 2011				
Petroleum and natural gas properties				
Cost	$ 17,271	$ 4,370	$ 451	$ 22,092
Accumulated depletion, depreciation and accretion	(16,126)	(3,554)	(451)	(20,131)
Net book value	$ 1,145	$ 816	$ -	$ 1,961
Exploration and evaluation assets	$ 8,274	-	841	$ 9,115
Accumulated impairment losses	(702)	-	-	(702)
Net book value	$ 7,572	$ -	$ 841	$ 8,413

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

For the three months ended June 30, 2010	**Australia**	**Canada**	**Other[1]**	**Total**
Revenue	$ 203	$ 146	$ -	$ 349
Net loss	(156)	(518)	(48)	(722)
Petroleum and natural gas property expenditures	$ -	$ -	$ -	$ -
Exploration and evaluation expenditures	$ 18	$ 29	$ 46	$ 93
As at March 31, 2011				
Petroleum and natural gas properties				
Cost	16,733	4,368	451	$ 21,552
Accumulated depletion, depreciation and accretion	(15,551)	(3,520)	(451)	$ (19,522)
Net book value	1,182	848	-	2,030
Exploration and evaluation cost	6,315	-	749	$ 7,064
Accumulated Impairment losses				$ -
Net book value	6,315	-	749	7,064

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

16. TRANSITION TO IFRS

As stated in Note 2, these are the Company's first 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 have been applied in the preparation of these financial statements for the quarter ended June 30, 2011, as well as in the preparation of the comparative information presented for the year ended March 31, 2011, the quarter ended June 30, 2010 and in the opening IFRS balance sheet at April 1, 2010 (the "transition date"), 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 is 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 values 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 the date of transition for the and comparative periods 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

	Note	March 31, 2011 CDN GAAP	March 31, 2011 Adj	March 31, 2011 IFRS	June 30, 2010 CDN GAAP	June 30, 2010 Adj	June 30, 2010 IFRS	April 1, 2010 CDN GAAP	April 1, 2010 Adj	April 1, 2010 IFRS
		($)	($)	($)	($)	($)	($)	($)	($)	($)
ASSETS										
Current assets										
Cash & cash equivalents	**A**	14,623	(23)	14,600	637	-	637	1,055	-	1,055
Restricted cash	**A**	1,212	15	1,227	160	-	160	510	-	510
Accounts receivable		817	-	817	351	-	351	273	-	273
Prepaid expenses & deposits	**A**	95	(4)	91	113	(2)	111	103	(3)	100
		16,747	(12)	16,735	1,261	(2)	1,259	1,941	(3)	1,938
Non-current assets										
Petroleum and natural gas properties	**A & B**	8,777	(6,747)	2,030	5,423	(3,593)	1,830	5,427	(3,505)	1,922
Exploration & evaluation assets	**A & B**	-	7,064	7,064	-	3,604	3,604	-	3,553	3,553
Total assets		25,524	305	25,829	6,684	9	6,693	7,368	45	7,413
LIABILITIES & SHAREHOLDER'S EQUITY										
Current liabilities										
Accounts payable & accrued liabilities		2,672	-	2,672	628	-	628	666	-	666
		2,672	-	2,672	628	-	628	666	-	666
Non-current liabilities										
Decommissioning liability	**C**	138	21	159	94	21	115	93	22	115
		138	21	159	94	21	115	93	22	115
Total liabilities		2,810	21	2,831	722	21	743	759	22	781
Shareholder's equity										
Share capital		62,595	-	62,595	43,468	-	43,468	43,460	-	43,460
Warrants		705	-	705	544	-	544	490	-	490
Contributed surplus	**D**	4,280	(91)	4,189	3,913	8	3,921	3,871	19	3,890
Accumulated other comprehensive income		-	95	95	-	(48)	(48)	-	-	-
Deficit	**A to D**	(44,866)	280	(44,586)	(41,963)	28	(41,935)	(41,212)	4	(41,208)
		22,714	284	22,998	5,962	(12)	5,950	6,609	23	6,632
Total liabilities & shareholder's equity		$ 25,524	305	25,829	$ 6,684	$ (9)	$ 6,693	$ 7,368	$ 45	$ 7,413

Reconciliation of Net Earnings for the Year Ended March 31, 2011 and the Quarter Ended June 30, 2010.		March 31, 2011			June 30, 2010		
		CDN GAAP	Adj	IFRS	CDN GAAP	Adj	IFRS
		$000's	$000's	$000's	$000's	$000's	$000's
Petroleum and natural gas		1,853	-	1,853	349	-	349
Royalties		(181)	-	(181)	(28)	-	(28)
Revenue		1,672	-	1,672	321	-	321
Operating expenses							
General and administrative	**	3,277	(19)	3,258	687	(17)	670
Operating and transportation		883	-	883	179	-	179
Depletion and depreciation	B	610	(267)	343	98	(19)	79
Pre-licensing and impairment	B	-	82	82	-	2	2
Stock-based compensation	D	641	(110)	531	104	(11)	93
Total expenses		5,411	(314)	5,097	1,068	(45)	1,023
Operating loss		(3,739)	314	(3,425)	(747)	45	(702)
Other income (expenses)							
Interest income		119	-	119	-	-	-
Finance and accretion		-	(20)	(20)	-	(18)	(18)
Foreign exchange gain (loss)		(34)	20	(14)	(4)	2	(2)
		85	-	85	(4)	(16)	(20)
Net Loss		(3,654)	314	(3,340)	(751)	29	(722)
Exchange differences on translation of foreign operations	A	-	(22)	(22)	-	(48)	(48)
Total comprehensive loss for the period		(3,654)	292	(3,362)	(751)	(19)	(770)

** At June 30, 2010 letter of credit charges of $17,000 (March 31, 2011 $19,000) 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 year ended March 31, 2011 as follows: Decrease in cash of $23,000; increase in restricted cash of $15,000; decrease in prepaid expenses and deposits of $4,000; increase in Exploration and Evaluation ("E&E") assets of $83,000 and an increase in Development & Production ("D&P") assets of $54,000 offset by $125,000 decrease to deficit.

The impact for the three months ended June 30, 2010 is as follows: decrease in prepaid expenses and deposits of $2,000 and a decrease in E&E assets of $3,000 offset by an increase to deficit of $5,000.

The impact at April 1, 2010 is as follows: decrease in prepaid expenses and deposits of $3,000; increase in E&E assets of $9,000 and an increase in D&P assets of $46,000 offset by a decrease to deficit of $51,000.

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 may be deemed zero at the date of transition.

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 22)

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:

At April 1, 2010, $3,544,000 reclassified from property, plant and equipment to E&E assets; for the three months ended June 30, 2010 a reduction in D&P assets of $3,610,000 with an corresponding increase in E&E assets of $3,607,000 and $3,000 charged to the statement of operations and loss for pre-licensing costs; for the year ended March 31, 2011 a reduction in D&P assets of $7,064,000 with a corresponding increase in E&E assets of $6,982,000 and $82,000 charged to the statement of operations and loss for 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 three months ended June 30, 2010 the use of proved plus probable reserves resulted in a decrease to depletion of $17,000 (year ended March 31, 2011 $263,000) 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.

The IFRS 1 exemption was utilized for decommissioning obligation associated with oil and gas properties and the Company re-measured asset retirement obligations as at April 1, 2010 under IAS 37 with a corresponding adjustment to opening retained deficit. Upon transition to IFRS this resulted in a $22,000 increase in the decommissioning obligations with a corresponding decrease in deficit.

At June 30, 2010, using a risk free rate of four percent, the Company increased its decommissioning obligations by $21,000 (March 31, 2011 - $21,000) from the previous GAAP amount. The Company also increased the value of its D&P assets for June 30, 2010 and March 31, 2011 by $21,000.

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 stock-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 occured. 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 decrease in the deficit at April 1, 2010.

An increase of $23,000 has also been made as at June 30, 2010 (March 31, 2011 - $36,000) in the stock based compensation expense offset by a decrease in Warrant amortization of $34,000 (March 31, 2011 - $144,000) in order to reflect the difference of the expense recognized under GAAP and IFRS.

E. Cash flow statement

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

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Valiant Trust Corporation • Calgary, Canada

INVESTOR RELATIONS

Bryan Mills Iradesso • Calgary, Canada

DIRECTORS

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

GOVERNANCE AND DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Bryan 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