Bengal
ENERGY LTD.

International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended
September 30, 2012 and 2011

HIGHLIGHTS

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

- **100% Drilling Success at Cuisinier:** Since March 2012, Bengal has drilled four oil producers, resulting in a drilling success rate of eight for eight in the Cooper Basin of Australia. The Company is currently producing 325 bopd from two of the newly drilled wells, under Extended Production Test, while certain regulatory and capacity constraints limit full production from all the wells. The following presents the current status of the Company's Cuisinier wells:

  The Company is currently trucking its production to a nearby terminal. The operator of the field is progressing plans for facilities upgrades and pipeline connection to large facility at an adjacent field that should handle production from all wells in the field. The operator is also applying for a Petroleum Lease ("PL") that will allow all the wells in the field to produce at their productive capacities. The Company expects regulatory approval and facilities upgrades to be completed in the quarter ending June 30, 2013.

Well	Productive Capacity	Status
Cuisinier 1, 2 and 3	125 bopd (aggregate)	Shut-in, awaiting PL
Cuisinier 4	125 bopd	Shut-in, awaiting tie-in
Cuisinier 5 and 6	325 bopd (aggregate)	Production Test
Barta North and Cuisinier North 1	75 bopd (aggregate)	Shut-in awaiting tests and tie-in
Total	**625 bopd**	

- **Cuisinier Reserves Increase Substantially:** A reserves update completed in September by GLJ Petroleum Consultants Ltd. recognized 717,000 proved barrels (an increase of 904%), 1,550,000 proved plus probable barrels (an increase of 269%) and 7,512,000 proved plus probable plus possible barrels (an increase of 614%) to Bengal. The net present values discounted at 10% amount to $16 million for proved, $37 million for proved plus probable and $164 million for proved plus probable plus possible.

- **Company's New Rig Drills First Well at Tookoonooka:** The Company's recently purchased drilling rig, Bengal 1, has been fully commissioned and, on October 5th commenced drilling of the first well at Tookoonooka on the Company's 100% owned ATP732P in the Cooper Basin. The first exploration well in the Company's Tookoonooka drilling campaign, Caracal-1, has been cased as a potential oil producer awaiting testing results.

- **Bengal Reports Financial Results:** The Company reported that revenues in the three and the six months amounted to $437,000 and $935,000, respectively compared to $1,017,000 and $2,336,000 respectively in 2011. The lower revenues resulted from production reductions primarily related to expiration of Extended Production Tests for the Cuisinier 1, 2 and 3 wells. The net loss for the three and six month periods amounted to ($845,000) or ($0.02) per share and ($1,056,000) or ($0.02) per share, respectively compared to ($4,247,000) or ($0.08) per share and ($5,308,000) or ($0.10) per share, respectively. The 2011 losses were impacted by an impairment loss related to the drilling of two dry holes in 2011 and 2008. The Company spent $10,299,000 in the three-month period ended September 30, 2012 and $17,625,000 in the six- month period ended September 30, 2012 related to the drilling of four Cuisinier wells, the acquisition of the Rig, seismic acquisition in Australia and India and preparation for drilling the Caracal-1 well.

MANAGEMENT'S DISCUSSION AND ANALYSIS – NOVEMBER 9, 2012

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Bengal Energy Ltd. ("Bengal" or the "Company") should be read in conjunction with the unaudited Condensed Consolidated Interim Financial Statements and accompanying notes for the three and six months ended September 30, 2012 and 2011 and the audited Consolidated Financial Statements and accompanying notes for the years ended March 31, 2012 and 2011. Bengal's financial statements were prepared under International Financial Reporting Standards ("IFRS"). Additional information relating to the Company, including detailed reserve disclosures, is included in the Company's Annual Information Form, which is available on SEDAR at www.sedar.com. The reader should be aware that historical results are not necessarily indicative of future performance.

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

OUTLOOK

AUSTRALIA – Onshore

Authority to Prospect ("ATP") 752 Barta Block

Previously the Company participated for its 25% working interest in the drilling of 4 successful Murta formation oil wells. These successful wells have now extended the oil bearing DC 70 trend to 4400 metres from south to north. Completion and tie in activity for the four new wells and the existing Barta North well was initiated during the quarter with expected onstream date of early December.

This successful drilling campaign prompted a review of the Cuisinier reserves with a reserves update completed by GLJ Petroleum Consultants in September (the results of this reserves update were contained in an October 5, 2012 press release).

The GLJ report has assigned 7.5 million Proved plus Probable plus Possible ("3P") barrels of oil to the Company's interest in the Cuisinier property, a 614% increase from March 31, 2012. Proved reserves increased to 0.7 million barrels, a 904% increase from March 31, 2012, while Proved plus Probable ("2P") reserves increased to 1.5 million barrels, a 269% increase.

A new 3D seismic survey covering approximately 224 square kilometers commenced in October north of and adjoining the current 3D seismic data set, Cuisinier wells and development area, and will be aimed at imaging Murta, Birkhead and Hutton anomalies, both structural and stratigraphic.

Engineering work is underway to convert the Cuisinier 1 site to a field satellite to which all well production will be produced and metered. Activities have commenced for the connection of the Cuisinier production to the neighboring and existing Cook production facility via pipeline. Regulatory delays relative to the granting of a long-term Petroleum Production License for Cuisinier continue with the operator estimating approval to be granted in the quarter ended June 30, 2013.

Bengal has recently been advised by the operating company of an expected restart date for Cuisinier 1, 2 and 3 in the second quarter of calendar 2013; however as the current production throughput capacity for all Cuisinier wells is approximately 1,300 barrels per day gross (325 barrels per day net to Bengal), existing production infrastructure will be fully utilized by the 4 new wells and Barta North 1 coming on stream and therefore Cuisinier 1, 2 and 3 will only come on stream once the above mentioned pipeline is complete.

ATP 732 Tookoonooka Block

Utilizing the recently acquired and 100%-owned drilling rig ("Bengal 1" or the "Rig"), drilling operations on the first of three initial exploratory wells on the Tookoonooka Block commenced in October. The Bengal Caracal-1 exploration well was spud on October 5, 2012.

The Rig was shipped, along with various ancillary equipment, from Dubai, UAE and successfully imported into Brisbane, Queensland via the Australian Quarantine and Inspection Service. Since receiving the rig and ancillary equipment from the importation process over the month of July, operations at Bengal's yard in Darra, Queensland focused on bringing the rig, mud and support systems and equipment to a compliant, fit-for purpose condition. Ongoing and final mechanical and electrical inspections confirmed the status of the rig and systems as being at a drill-ready state. The rig was shipped to the newly-constructed site of the initial well in the ATP 732 drilling campaign, Caracal-1, in the first week of September.

The three drill locations selected for the drilling campaign are targeting Cretaceous and Jurassic oil as well as Permian gas. All three locations have been chosen based on their multi-zone potential with as many as three or four prospective targets on each location.

The primary target on Caracal-1 was oil in the Cretaceous Wyandra and Murta Formation sandstones with the Jurassic Hutton, Birkhead and Westbourne Formation sandstones as secondary targets. Subsequent to the current quarter end, Caracal 1 has been cased pending perforation and testing to confirm the prospectivity of this well as a future oil producer. The Caracal-1 well encountered a developed sandstone at the Cretaceous Wyandra level. An eighteen meter core was cut over the Wyandra section with preliminary petrophysical analysis indicating a total of 9.2 meters of porous sandstone with an average of 18% porosity. The Company advises that the core, the samples and the subsequently taken sidewall cores all have positive indications of hydrocarbons; yet these indications are not uniform across the entire interval. The Company notes that drilling fluid invasion, which occurred during the coring operation, may have adversely affected the resistivity logging response, as such response is inconsistent with similar data from other Wyandra producers in offset producing fields. Formation fluids will need to be produced from the Caracal-1 well prior to making a final determination of the status of this well and plans are underway to have the well completed and production tested in late November. The Company holds a 100% working interest in ATP 732.

ATP 934 Barrolka Block

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

Australia - Offshore

AC/P 47 Block

On October 19, 2012 Bengal received an extension to the time period to complete the scheduled work commitment for this offshore permit from the National Offshore Petroleum Titles Administrator (NOPTA). If a joint venture partner is found, the Company would then shoot, process and interpret a minimum of 750 square km of 3D seismic on this permit during 2012 and Q1 2013. The results of this seismic program will give Bengal the option of either committing to drill an exploration well or, if no acceptable prospects are identified from the seismic interpretation, relinquishing the permit. If the permit is relinquished, $0.8 million of historical exploration and evaluation costs plus the Company's share of any seismic program costs will be impaired.

India - Onshore

CY-ONN-2005/1 Block

On Bengal's 30% working interest, 233,000 gross acre Block CY-ONN-2005/1 located in the onshore Cauvery Basin, Bengal and its joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, completed the acquisition of approximately 600 square km of 3D seismic in October. Seismic data processing has commenced with preliminary interpretation now underway.

As well, airborne magnetometry work was carried out over the permit in association with the seismic program. These geophysical data sets will allow the joint venture to define drilling locations on the permit early in 2013 with three wells planned. These wells will target Cretaceous reservoirs known to produce from pools offsetting the permit to the north and west. Target depths will be between 1000m and 2500m.

India - Offshore

CY-OSN-2009/1 Block

Evaluation work is continuing on this 340,000 acre, 100% owned and operated Block CY-OSN-2009/1 in India's offshore Cauvery basin. Activity includes acquiring 2D and 3D surveys previously recorded on the block and in this region and reprocessing of certain available seismic records. Interpretation of the various seismic data sets has been completed with several play types and prospects emerging. This has now allowed planning to progress on a new seismic data program, with the acquisition of additional seismic data planned for 2013.

Recent competitor activity in the local area, including the $7.2 billion acquisition by BP of a 30% interest in a number of blocks held by Reliance and the recently announced exploration discoveries by Cairn India in nearby Sri Lankan waters provide encouragement for acceleration of the Bengal activity. Preliminary work suggests that the prospects identified on the Company permit occur in a geological section and with a prospect style similar to that of the Cairn discoveries.

The Company is actively seeking farm-in partners on this block.

Canada

On September 1, 2012 the Company shut in its gas wells at Oak British Columbia due to low gas prices. In the prior two months these wells had contributed 43 and 45 boe/d and nil net operating income. The Company will consider bringing these wells back on production when justified by increased gas prices.

SUMMARY

The Company has an attractive portfolio of both lower-risk and high-impact drilling opportunities. Increasing production from new wells at Cuisinier on the Barta permit should drive operating income for the Company and set the stage for future development. Potential near-term exploration drilling success on permit ATP 732P could create further momentum. Longer term plays in India are designed to potentially add value in 2013 and onward. The Company will continue to evaluate accretive production acquisition, exploration and corporate transaction opportunities, as and where they arise, within and around the Company's core areas.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended September 30			Six Months Ended September 30		
	2012	2011	% Change	**2012**	2011	% Change
Revenue						
Natural gas	**$ 31**	$ 67	(54)	**$ 70**	$ 159	(56)
Natural gas liquids	**19**	13	46	**45**	29	55
Oil	**387**	937	(59)	**820**	2,148	(62)
Total	**437**	1,017	(57)	**935**	2,336	(60)
Royalties	**38**	95	(60)	**83**	216	(62)
% of revenue	**8.7**	9.3	(7)	**8.9**	9.2	(3)
Operating & transportation	**162**	316	(49)	**409**	838	(51)
Netback[1]	**237**	606	(61)	**443**	1,282	(65)
Cash from (used in) operations:	**315**	159	(98)	**(444)**	(1,212)	(63)
Per share ($) (basic & diluted)	**0.01**	0.00	-	**(0.01)**	(0.02)	(50)
Funds from (used in) operations:[2]	**(471)**	(430)	10	**(533)**	(423)	26
Per share ($) (basic & diluted)	**(0.01)**	(0.01)	-	**(0.01)**	(0.01)	–
Net (loss):	**(845)**	(4,247)	(80)	**(1,056)**	(5,308)	(80)
Per share ($) (basic & diluted)	**(0.02)**	(0.08)	(75)	**(0.02)**	(0.10)	(80)
Capital expenditures	**$ 10,299**	$ 2,407	328	**$ 17,625**	$ 4,340	306
Volumes						
Natural gas (mcf/d)	**159**	196	(19)	**192**	221	(13)
Natural gas liquids (boe/d)	**3**	3	-	**4**	3	33
Oil (bbl/d)	**35**	94	(63)	**41**	100	(59)
Total (boe/d @ 6:1)	**65**	130	(50)	**77**	140	(45)
Netback[1] ($/boe)						
Revenue	**$ 73.90**	$ 86.21	(14)	**$ 67.02**	$ 91.20	(27)
Royalties	**6.43**	8.01	(20)	**5.95**	8.42	(29)
Operating & transportation	**27.40**	26.78	2	**29.32**	32.70	(10)
Total	**$ 40.07**	$ 51.42	(22)	**$ 31.75**	$ 50.08	(37)

(1) Netback is a non-IFRS measure. Netback per boe is calculated by dividing the revenue and costs in total for the Company by the total production of the Company measured in boe.
(2) Funds from operations is a non-IFRS measure. The comparable IFRS measure is cash from operations. A reconciliation of the two measures can be found in the table on page 6.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the three and six months ended September 30, 2012. The terms “current quarter” and “the quarter” are used throughout the MD&A and in all cases refer to the period from July 1, 2012 through September 30, 2012. The terms “prior year’s quarter” and “2011 quarter” are used throughout the MD&A for comparative purposes and refer to the period from July 1, 2011 through September 30, 2011.

The fiscal year for the Company is the 12-month period ended March 31, 2013. The terms “fiscal 2013,” “current year” and “the year” are used in the MD&A and in all cases refer to the period from April 1, 2012 through March 31, 2013. The terms “previous year,” “prior year” and “fiscal 2012” are used in the MD&A for comparative purposes and refer to the period from April 1, 2011 through March 31, 2012.

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

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

Non-IFRS Measurements

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

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

	Three Months Ended September 30		Six Months Ended September 30	
$000s	**2012**	2011	**2012**	2011
Cash flow from (used in) operating activities	**315**	159	**(444)**	(1,212)
Changes in non-cash working capital	**(786)**	(589)	**(89)**	789
Funds from (used in) operations	**(471)**	(430)	**(533)**	(423)

RESULTS OF OPERATONS

Production

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

Production	Three Months Ended September 30			Six Months Ended September 30		
	2012	2011	% Change	**2012**	2011	% change
Natural gas (mcf/d)	**159**	196	(19)	**192**	221	(13)
NGLs (boe/d)	**3**	3	-	**4**	3	33
Oil (bbls/d)	**35**	94	(63)	**41**	100	(59)
Total (boe/d)	**65**	130	(50)	**77**	140	(45)

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

The decrease in oil production is due to the shut-in of the Cuisinier 1 well in January 2012 and shut in of Cuisinier 2 and 3 in August and September of 2013. The Company is awaiting regulatory approval of a Long-Term Petroleum Production License which is expected in the second quarter of calendar 2013.

On September 1, 2012 the Company shut in its gas wells at Oak British Columbia due to low gas prices. In the prior two months these wells had contributed 43 and 45 boe/d. The Company will consider bringing these wells back on production when justified by increased gas prices. As at September 30, 2012 the Company had nil production but in October 2012 production commenced from the Cuisinier 4, 5 and 6 wells at a combined rate of 1,800 b/d gross (450 b/d net). Cuisinier 5 at 500 b/d gross (125 b/d net) was subsequently shut in due to capacity limitations. The capacity of facilities at Cuisinier is 1,300 b/d gross and therefore the wells will produce at restricted rates or alternate between being shut-in and producing in order not to exceed capacity.

Pricing

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

Prices and Marketing				**Three Months Ended September 30**					**Six Months Ended September 30**
		2012		2011	% Change		**2012**		2011	% Change
Average Benchmark Prices										
AECO 30 day firm ($/mcf)	**$**	**2.19**	$	3.72	(41)	**$**	**2.01**	$	3.73	(46)
Dated Brent oil ($US/bbl)		**109.19**		112.08	(3)		**109.00**		114.04	(4)
Number of CAD$ for 1 AUD$		**1.04**		1.03	1		**1.03**		1.03	-
Number of CAD$ for 1 USD$		**1.00**		0.98	2		**1.00**		0.97	3
WTI oil ($US/bbl)		**92.24**		87.90	5		**92.17**		95.80	(4)
Bengal's Realized Price ($CAD)										
Natural gas ($/mcf)	**$**	**2.11**	$	3.73	(43)	**$**	**1.99**	$	3.92	(49)
NGLs ($/bbl)		**68.59**		50.64	35		**69.44**		60.55	15
Oil ($/bbl)		**121.32**		109.51	11		**110.19**		116.86	(6)
Total ($/boe)		**73.90**		86.21	(14)		**67.02**		91.20	(27)

Bengal's total realized price on a boe basis decreased as a result of both lower oil and gas prices.

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 averaged USD$5.28/bbl over Brent for the six month period ended September 30, 2012.

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 ($000s)		**Three Months Ended September 30**					**Six Months Ended September 30**			
		2012		2011	% Change		**2012**		2011	% Change
Natural gas	**$**	**31**	$	67	(54)	**$**	**70**	$	159	(56)
NGLs		**19**		13	46		**45**		29	55
Oil		**387**		937	(59)		**820**		2,148	(62)
Total	**$**	**437**	$	1,017	(57)	**$**	**935**	$	2,336	(60)

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

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

Petroleum and natural gas sales for the are lower in the current quarter and YTD due to lower volumes and prices. The Company's Oak B.C. gas property was shut in September 1, 2013 due to low prices, while the Company's Cuisinier 1, 2 and 3 wells are shut in awaiting a Production License grant by the Queensland Government.

Royalties

Royalties by Type ($000s)		Three Months Ended September 30				Six Months Ended September 30		
		2012		2011	% Change	**2012**		2011	% Change
Canada Crown	**$**	**-**	$	6	(100)	**$**	**3**	$	12	(75)
Can. gross overriding		**3**		3	-		**6**		9	(33)
Australia		**35**		86	(59)		**74**		195	(62)
Total	**$**	**38**	$	95	(60)	**$**	**83**	$	216	(62)
$/boe		**6.43**		8.01	(20)		**5.95**		8.42	(29)
% of revenue		**8.7**		9.3	(7)		**8.9**		9.2	(3)

Royalties by Commodity		Three Months Ended September 30					Six Months Ended September 30		
		2012		2011	% Change		**2012**		2011	% Change
Natural gas										
$000s	**$**	**-**	$	5	(100)	**$**	**1**	$	14	(93)
$/mcf		**(0.01)**		0.26	(104)		**0.02**		0.33	(94)
% of revenue		**-**		7.0	(100)		**1.4**		8.4	(83)
Oil										
$000s	**$**	**35**	$	86	(59)	**$**	**74**	$	195	(62)
$/bbl		**10.97**		10.07	9		**9.94**		10.62	(6)
% of revenue		**9.0**		9.2	(2)		**9.0**		9.1	(1)
NGLs										
$000s	**$**	**3**	$	4	(25)	**$**	**8**	$	7	14
$/bbl		**11.34**		13.95	(19)		**12.88**		14.72	(13)
% of revenue		**15.8**		27.5	(43)		**17.8**		24.3	(27)

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

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

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

Royalties have declined in the current quarter and YTD both on a dollar basis and per boe due to lower prices and volumes.

Operating & Transportation Expenses

Operating Expenses ($000s)		Three Months Ended September 30				Six Months Ended September 30			
		2012		2011	% Change		**2012**		2011	% Change
Australia										
Operating	**$**	**44**		122	(64)	**$**	**133**	$	349	(62)
Transportation		**65**		150	(57)		**147**		323	(54)
		109		272	(60)		**280**		672	(58)
Canada – Oper. costs		**53**		44	20		**129**		166	(22)
Total	**$**	**162**	$	316	(49)	**$**	**409**	$	838	(51)
Australia										
Operating - $/boe		**13.79**		14.23	(3)		**17.87**		18.95	(6)
Transp. - $/boe		**20.38**		17.59	16		**19.75**		17.59	12
Canada - $/boe		**19.46**		13.47	45		**19.82**		22.97	(14)
Total ($boe)	**$**	**27.40**	$	26.78	2	**$**	**29.32**	$	32.70	(10)

Operating and transportation expenses in the quarter decreased by $154,000 to $162,000. The decrease is primarily due to lower sales volumes due to shut-in of the Oak B.C. gas property and the Cuisinier 1 and 2 wells during the quarter. Costs per boe increased in Canada by 45% to $19.46 due to additional costs required to prepare the wells and facilities for shut down.

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

Operating costs decreased 51% on a year over year basis due to lower production volumes.

General and Administrative (G&A) Expenses

General and Admin. Expenses ($000s)	**Three Months Ended September 30**			**Six Months Ended September 30**		
	2012	2011	% Change	**2012**	2011	% Change
G&A	**$ 1,113**	$ 1,026	8	**$ 2,196**	$ 1,788	23
Capitalized G&A	**(238)**	–	100	**(238)**	–	100
Net G&A	**$ 875**	$ 1,026	(15)	**$ 1,958**	$ 1,788	10

For the quarter, gross G&A expenses increased $87,000 or 9% to $1,113,000 compared to $1,026,000 in the 2011 quarter. The increase is due to costs associated with the mid-year reserve update on the Cuisinier property in Australia and higher rents in the current quarter as the Company moved on April 1, 2012 from lower cost sub-let space to new space due to the expiry of the sub-lease.

YTD gross G&A has increased $408,000 or 23% from the prior YTD. The increase in costs is due to the mid-year Cuisinier reserve update, higher rent and higher salaries from hiring a Vice President, Engineering and Operations and a Senior Geologist and Geophysicist.

During the quarter, the Company began capitalizing G&A expenses associated with geological, geophysical and engineering expenses associated with exploration and development activities concurrent with the Company being operator for the first time and similar expenses associated with its newly acquired drilling rig.

Share-based Compensation (SBC)

Stock-Based Compensation ($000s)	**Three Months Ended September 30**			**Six Months Ended September 30**		
	2012	2011	% Change	**2012**	2011	% Change
SBC – options	**$ 163**	$ 240	(32)	**$ 370**	$ 517	(28)
SBC – capitalized	**(83)**	-	100	**(117)**	-	100
Stock-based compensation	**$ 80**	$ 240	(67)	**$ 253**	$ 517	(51)

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

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

During the current period and subsequently to the date of this report, no stock options were granted; exercised, expired or forfeited. The decrease in share-based compensation, before capitalization, from $517,000 to $401,000 YTD and $240,000 to $156,000 in the current quarter is a result of having an option grant in the six month period ended September 30, 2011 and none in the current period.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2012	2011	% Change	**2012**	2011	% Change
DD&A – Australia	**$ 66**	$ 75	(12)	**$ 124**	$ 138	(10)
DD&A – Canada	**30**	29	3	**65**	63	3
Total	**$ 96**	$ 104	(8)	**$ 189**	$ 201	(6)
$/boe – Australia	**20.69**	8.78	136	**16.66**	7.51	122
$/boe – Canada	**11.02**	8.90	24	**9.99**	8.70	15
$/boe – Total	**$ 16.24**	$ 8.81	84	**$ 13.55**	$ 7.84	73

Depletion per boe increased in Australia due to the increase in future capital costs related to the significant increase in reserves at September 30, 2012.

Impairment

Impairment ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2012	2011	**% Change**	**2012**	2011	% Change
	$ 89	$ 3,638	(98)	**$ (758)**	$ 4,340	(118)

At June 30, 2012 the Company reported an $847,000 impairment recovery against the aforementioned well as a result of a settlement agreement reached with the operator which was partially offset by the final costs billed for the Kingtree well drilled and abandoned in October 2011.

At September 30, 2011 the Company reported a $4,340,000 impairment loss against exploration and evaluation assets. The impairment related to costs incurred on permit AC/P24 which were determined to be impaired after drilling the Kingtree well in October 2011 and, drilling costs charged in the period for the dry and abandoned Hudson well which was drilled in 2008.

Finance Income

Finance income ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2012	2011	% Change	**2012**	2011	% Change
Interest income	$ **65**	168	**(61)**	**$ 157**	$ 308	(49)

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

Finance Expenses

Finance Expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2012	2011	% Change	**2012**	2011	% Change
Accretion expense on decommissioning liabilities	**$ 1**	$ -	100	**$ 4**	$ 2	100
Performance Security Guarantee fee	**-**	2	(100)	**23**	44	(48)
Finance expenses	**$ 1**	$ 2	(50)	**$ 27**	$ 46	(41)

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

Funds from (used in) Operations and Net Loss

For the three months ended September 30, 2012 funds used in operations was $471,000 or $0.01 per basic and diluted share compared to funds used in operations of $430,000 or $0.01 per basic and diluted share in the 2011 quarter. The changes in non-cash working capital and abandonment expenditures are removed from the IFRS measure cash flow from (used in) operations to arrive at the non-IFRS measure funds from (used in) operations (see reconciliation on page 7).

The net loss for the three months ended September 30, 2012 was $845,000 or $0.02 per basic and diluted share compared to a loss of $4,247,000 or $0.08 per basic and diluted share in the 2011 quarter. The reduced loss was due to the impairment of the offshore Australia Kingtree well in the prior year.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	**Three Months Ended September 30**			**Six Months Ended September 30**		
	2012	2011	% Change	**2012**	2011	% Change
Geological and geophysical	**$ 1,618**	$ 696	98	**$ 2,689**	878	179
Drilling	**6,183**	1,362	348	**9,072**	2,064	335
Drilling Rig	**1,317**	-	-	**4,334**	-	-
Completions	**1,181**	349	238	**1,518**	1,398	9
Total oil & gas expenditures	**10,299**	2,407	318	**17,613**	4,340	300
Office	**-**	-	-	**12**	-	-
Total expenditures	**$ 10,299**	$ 2,407	318	**$ 17,625**	$ 4,340	300
Exploration & evaluation expenditures	**$ 6,327**	$ 2,055	208	**$ 8,477**	$ 3,992	112
Development & production expenditures	**2,655**	352	654	**4,814**	348	1,283
Property, plant and equipment	**1,317**	-	-	**4,334**	-	100
Total net expenditures	**$ 10,299**	2,407	328	**$ 17,625**	$ 4,340	306

The Company incurred $2,404,000 in seismic expenditures on its onshore India permit CY-ONN-2005/1 to complete a 502 square kilometer 3D seismic shoot and a 75 square kilometer high resolution 3D seismic shoot in the six months ended September 30, 2012.

In the six months ended September 30, 2012, drilling and completion expenditures were incurred to drill and complete four Cuisinier appraisal wells on the Company's ATP 752 permit and for drilling and lease preparation costs required for the Company's upcoming operated drilling program on permit ATP 732 in the Cooper Basin onshore Australia.

Expenditures of $1,751,000 million were incurred to purchase an Ideco H-44 drilling rig. The Company spent a further $2,583,000 to transport the rig to Australia from its point of purchase, to clear customs, to buy certain ancillary equipment required for drilling operations and to make the rig ready for use.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. At November 9, 2012, there were 52,110,117 common shares issued and outstanding.

At November 9, 2012, there were 3,611,665 employee stock options outstanding with an average exercise price of $1.14 per share. Of these, 2,256,567 are exercisable at an average price of $1.11 per share. These options expire between 2012 and 2017 with an average remaining life of 3.1 years.

Trading History	Three Months Ended September 30					Six Months Ended September 30				
		2012		2011	% Change		**2012**		2011	% Change
High	**$**	**0.90**	$	1.44	(38)	**$**	**1.05**	$	2.06	(49)
Low		**0.58**		1.00	(42)		**0.52**		1.00	(48)
Close	**$**	**0.76**	$	1.25	(39)	**$**	**0.76**	$	1.25	(39)
Volume (000s)		**3,295**		4,722	(30)		**6,621**		10,332	(36)
Shares outstanding (000s) Basic and diluted		**52,110**		51,961	-		**52,110**		51,961	-
Weighted average shares outstanding (000s) Basic and diluted		**52,110**		51,961	-		**52,110**		50,878	2

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2012 the Company had working capital of $7.6 million, including cash and short term deposits of $12.3 million and restricted cash of $0.1 million, compared to working capital of $33.1 million, including cash and short term deposits of $35.2 million and restricted cash of $0.1 million at September 30, 2011.

The Company's existing cash and cash equivalents and operating cash flows are not expected to be sufficient to meet all of its commitments under its capital program (see Note 11 to the Financial Statements), and accordingly the Company will need to raise additional equity capital, debt financing or farm out portions of its property interests.

The Company is actively marketing the opportunity for interested parties to farm in to its operated oil and gas permits in 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.

COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. 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. See note 2 of the Financial Statements for further details with respect to financing alternatives for fulfilling these obligations.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 752	shoot 224 km² 3D seismic	December 31, 2012	$ 1.2
Offshore Australia – AC/P47	750km^2 3D seismic	January 2, 2013(2)	$7.1
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$ 3.3
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$ 5.2

(1) Translated at September 30, 2012 exchange rate of US $1.0000 = CAD $0.9833 and AUD $1.0000 = CAD $1.0204

(2) Bengal received an extension to the time period to complete the scheduled work commitment for this offshore permit from the National Offshore Petroleum Titles Administrator (NOPTA) to January 2, 2013. Refer to Note 4 of the financial statements for measurement uncertainty associated with this permit.

CONTINGENCIES

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

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)[(1)]
Onshore Australia – ATP 934P	Awaiting Ministerial approval of Environmental Application before granting of ATP[(3)]	4 years after grant of ATP	$ 11.9

Guarantees – India Permits

($000s) CAD	**Quarter Ended September 30, 2012**	**Year ended March 31, 2012**
CY-ONN-2005/1 – Onshore India – year 1	**$ –**	**$ 1,104**
CY-OSN-2005/1 – Onshore India – year 2	**809**	**820**
CY-OSN-2009/1 – Offshore India	**149**	**151**
Total Guarantees	**$ 958**	**$ 2,075**

These performance guarantees are based on a percentage of the capital commitments shown in the table above and are not reflected in the statement of financial position as they are secured by Export Development Canada. These guarantees are cancelled when the Company completes the work program commitment required for the applicable exploration period.

Other

At September 30, 2012, the contractual obligations for which the Company is responsible are as follows:

Contractual Obligations ($000s)	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Office lease	$ 1,124	$ 251	$ 494	$ 379	$ -
Decommissioning obligations	296	-	-	-	296
Total contractual obligations	$ 1,420	$ 251	$ 494	$ 379	$ 296

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts	Sep. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sep. 30 2011	Jun. 30 2011	Mar. 31 2011
Petroleum and natural gas sales	**$ 437**	$ 498	$ 622	$ 1,328	$ 1,017	$ 1,319	$ 691
Cash from (used-in) operations	**315**	(759)	486	(417)	159	(1,371)	(725)
Per share Basic and diluted	**0.01**	(0.01)	0.01	(0.01)	0.00	(0.03)	(0.02)
Funds from (used in) operations[1]	**(471)**	(62)	(635)	(402)	(430)	7	(669)
Per share Basic and diluted	**(0.01)**	0.00	(0.01)	0.00	(0.01)	0.00	(0.02)
Net loss	**$ (845)**	$ (211)	$ (1,424)	$ (477)	$ (4,247)	$ (1,061)	$ (890)
Per share Basic and diluted	**(0.02)**	0.00	(0.03)	(0.01)	(0.08)	(0.02)	(0.03)
Capital expenditures	**$ 10,299**	$ 7,326	$ 2,233	$ 4,265	$ 2,407	$ 1,933	$ 1,978
Working capital	**7,578**	18,425	25,722	28,798	33,109	35,691	14,063
Total assets	**46,557**	44,484	43,696	44,899	45,696	51,072	25,829
Shares outstanding Basic and diluted	**52,110**	52,110	52,110	52,110	51,961	51,961	37,795
Operations							
Average daily production							
Natural gas (mcf/d)	**159**	225	304	271	196	249	348
Oil and NGLs (bbls/d)	**38**	51	52	112	97	110	59
Combined (boe/d)	**65**	89	103	157	130	152	117
Netback ($/boe)	**$ 40.07**	$ 24.51	$ 27.27	$ 49.89	$ 51.42	$ 48.92	$ 31.31

(1) See “Non-IFRS Measurements” on page 6 of this MD&A.

Beginning in the quarter ended March 31, 2010 and continuing through to the quarter ended December 31, 2011, oil volumes were increasing due to commencement of production from the Cuisinier 1 well in the Cooper Basin of Australia in May 2010 and the Cuisinier 2 and 3 wells in the quarter ended September 2011. Oil sales 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. Oil sales in the three most recent quarters have been impacted by the temporary shut in of Cuisinier 1 on January 13, 2012 and Cuisinier 2 and 3 in August and September 2012 while the Company waits for approval of a Production License. Gas volumes declined in the quarter ended September 30, 2011 due to a plant turnaround at the Oak B.C. property and are in a general decline due to natural reservoir declines. Gas volumes also declined in the quarter ended June 30, 2012 due to the removal of a rental screw compressor (due to low gas prices and the cost of the rental plus associated maintenance) and an unscheduled plant shutdown at the Oak property due to a leak in the line to the flare stack. Gas volumes declined in the quarter ended September 30, 2012 as the Company’s Oak B.C. gas property was shut in due to low gas prices.

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

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and includes controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company’s management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

The Chief Executive Officer and Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and Chief Financial Officer have individually signed certifications to this effect.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were ineffective at March 31, 2012 due to the material weaknesses noted below.

No changes in internal controls over financial reporting were identified during the period that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

While Bengal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design and operating effectiveness assessment certain material weaknesses in internal controls over financial reporting were identified, as follows:

- Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general and administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs;
- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advice on complex financial accounting issues and for tax planning, tax provision and compilation of corporate tax returns.

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

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 June 29, 2012 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 1810, 801 6th Avenue SW., Calgary, Alberta T2P 3W2, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

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

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

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Expectations that Bengal's future realized gas and oil prices will coincide with the B.C Station 2 and Brent daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cashflows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective;*
- *Commencement of exploration and development activities on Block CY-OSN-2009/1;*
- *Continuation of exploration, development activities on Permit AC/P 47 offshore Australia and whether the Company will be granted an extension to the time period to complete the work program on this permit to September 2, 2013 and whether a farm-out partner will be found on acceptable terms to the Company and if not, whether the Company will shoot seismic on this permit;*
- *Obtaining Native Title Agreement on ATP 934P in Australia and commencement of exploration activities;*
- *That drilling activities on ATP 732P will occur;*
- *That tie-in of five wells will occur on ATP 752P in calendar Q3 and Q4 of 2012 and seismic activity will follow drilling and that production from Cuisinier 2 and 3 will continue as expected and that a production license will be granted for Cuisinier 1 and it will re-commence production and that Cuisinier 4 through 6 and Cuisinier North 1 will produce oil and that transportation of the oil will occur.*

With respect to the forward looking statements contained in the MD&A, Bengal has made assumptions regarding: future commodity prices; the impact of royalty regimes; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital; the continued availability of undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continued stability of political, regulatory; tax and fiscal regimes in which the Company has operations.

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

- *Volatility in market prices for oil and natural gas;*
- *Liabilities inherent in oil and natural gas operations;*
- *Uncertainties associated with estimating oil and natural gas reserves;*

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

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

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

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Valiant Trust Corporation • Calgary, Canada

INVESTOR RELATIONS

Bryan Mills Iradesso • Calgary, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Bryan C. Goudie, Chief Financial Officer
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 Consolidated Interim Financial Statements (unaudited)

Three and six months ended September 30, 2012 and 2011

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(unaudited)

As at	Notes	September 30, 2012	March 31, 2012
ASSETS			
Current assets:			
Cash and cash equivalents		**$ 12,307**	$ 26,934
Restricted cash		**135**	135
Accounts receivable		**1,307**	1,009
Prepaid expenses and deposits		**110**	127
		13,859	28,205
Non-current assets:			
Exploration and evaluation assets	4	**18,763**	10,526
Petroleum and natural gas properties	5	**9,356**	4,735
Property, plant and equipment	6	**4,579**	230
		32,698	15,491
Total assets		**$ 46,557**	$ 43,696
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		**$ 6,281**	$ 2,483
Non-current liabilities:			
Decommissioning liability	7	**296**	228
Shareholders' equity:			
Share capital		**$ 86,246**	$ 86,246
Contributed surplus		**6,149**	5,779
Accumulated other comprehensive income		**398**	717
Deficit		**(52,813)**	(51,757)
		39,980	40,985
Total liabilities and shareholders' equity		**$ 46,557**	$ 43,696

Commitments (note 11)

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

		Three months		Six months	
For the three months ended September 30,	**Notes**	**2012**	**2011**	**2012**	**2011**
Income					
Petroleum and natural gas revenue		$ 437	$ 1,017	$ 935	$ 2,336
Royalties		(38)	(95)	(83)	(216)
		399	922	852	2,120
Operating expenses					
General and administrative		875	1,026	1,958	1,788
Operating and transportation		162	316	409	838
Depletion and depreciation	5	96	104	189	201
Pre-licensing and impairment	4	89	3,638	(758)	4,340
Share-based compensation		80	240	253	517
		1,302	5,324	2,051	7,684
Operating loss		(903)	(4,402)	(1,199)	(5,564)
Other income (expenses)					
Finance income		65	168	157	308
Finance expenses		(1)	(2)	(27)	(46)
Foreign exchange gain (loss)		(6)	(11)	13	(6)
		58	155	143	256
Net Loss		(845)	(4,247)	(1,056)	(5,308)
Exchange differences on translation of foreign operations		(518)	19	(319)	229
Total comprehensive loss for the period		$ (1,363)	$ (4,228)	$ (1,375)	$ (5,079)
Earnings per share	8				
- Basic & Diluted		$ (0.02)	$ (0.08)	$ (0.02)	$ (0.10)
Weighted average number of shares outstanding (000s)	8				
- Basic & Diluted		52,110	51,961	52,110	50,878

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

(unaudited)

	Shares outstanding	Share capital	Warrants	Contributed surplus	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2011	37,794,549	$ 62,595	$ 705	$ 4,189	$ 95	$ (44,586)	$ 22,998
Net loss for the period	-	-	-	-	-	(5,308)	(5,308)
Comprehensive loss for the period	-	-	-	-	229	-	229
Issue of share capital (Note 8)		23,478	-	-	-	-	23,478
Expiry of warrants			(705)	705			
Share based payments	-	-	-	519	-	-	519
Balance at September 30, 2011	**51,961,349**	**$ 86,073**		**$5,413**	**$ 324**	**$(49,894)**	**$ 41,916**
Balance at April 1, 2012	**52,110,177**	**$ 86,246**	**$**	**$ 5,779**	**$ 717**	**$ (51,757)**	**$ 40,985**
Net loss for the period	**-**	**-**	**-**	**-**	**-**	**(1,056)**	**(1,056)**
Comprehensive loss for the period	**-**	**-**	**-**	**-**	**(319)**	**-**	**(319)**
Share based payments - expensed	**-**	**-**	**-**	**253**	**-**	**-**	**253**
Share based payments - capitalized	**-**	**-**	**-**	**117**	**-**	**-**	**117**
Balance at September 30, 2012	**52,110,177**	**$ 86,246**	**$ -**	**$ 6,149**	**$ 398**	**$ (52,813)**	**$ 39,980**

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

(unaudited)

For the periods ended September 30,	Notes	Three months 2012	Three months 2011	Six months 2012	Six months 2011
Operating activities					
Net loss		**$ (845)**	$ (4,247)	**$ (1,056)**	$ (5,308)
Non-cash items:					
Depletion and depreciation		**96**	104	**189**	201
Pre-licensing and impairment		**89**	3,638	**89**	4,340
Accretion		**2**	-	**4**	2
Share-based compensation		**80**	240	**253**	517
Unrealized foreign exchange (gain) loss		**107**	(165)	**(12)**	(175)
Change in non-cash working capital	**10**	**786**	589	**89**	(789)
Net cash flow from (used in) operating activities		**315**	159	**(444)**	(1,212)
Investing activities					
Exploration and evaluation expenditures		**(6,327)**	(2,055)	**(8,477)**	(3,992)
Petroleum and natural gas properties		**(2,655)**	(352)	**(4,814)**	(348)
Property, plant & equipment		**(1,317)**	-	**(4,334)**	-
Change in restricted cash		**-**	-	**-**	1,092
Changes in investing working capital	**10**	**2,627**	(408)	**3,387**	1,380
Net cash flow used in investing activities		**(7,672)**	(2,815)	**(14,238)**	(1,868)
Financing activities					
Proceeds from issuance of shares, net of issuance costs		**-**	-	**-**	23,478
Changes in financing working capital	**10**	**-**	-	**-**	(82)
Net cash flow from financing activities		**-**	-	**-**	23,396
Impact of foreign exchange on cash and cash equivalents		**(84)**	255	**55**	331
Net increase/(decrease) in cash and cash equivalents		**$ (7,441)**	$ (2,401)	**$ (14,627)**	$ 20,647
Cash and cash equivalents, beginning of period		**19,748**	37,648	**26,934**	14,600
Cash and cash equivalents, end of period		**$ 12,307**	$ 35,247	**$ 12,307**	$ 35,247

See accompanying notes to condensed consolidated interim financial statements.

1. REPORTING ENTITY:

Bengal Energy Ltd (the “Company” or “Bengal”) is incorporated under the laws of the Province of Alberta and is involved in the exploration for and development of oil and gas reserves in Australia, India and Canada. The condensed consolidated interim financial statements (the “financial statements”) of the Company as at September 30, 2012 and for the three and six months ended September 30, 2012 and 2011 are comprised of the Company and its wholly owned subsidiaries Bengal Energy International Inc. and Bengal Energy (Australia) Pty Ltd. which are incorporated in Canada and Australia respectively. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company’s proportionate interest in such activities.

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

2. BASIS OF PREPARATION

These condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard (“IAS”) 34, “Interim Financial Reporting”. These condensed consolidated interim financial statements do not include all of the information required for full annual financial statements.

These condensed consolidated interim financial statements are stated in Canadian dollars and have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company for the year ended March 31, 2012. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company’s annual filings for the year ended March 31, 2012.

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 had $12.3 million in cash (March 31, 2012 - $26.9 million), $0.1 million in restricted cash (March 31, 2012 - $0.1 million) and working capital of $7.6 million at September 30, 2012 (March 31, 2012 - $25.7 million).

The Company’s existing cash and cash equivalents and operating cash flows are not expected to be sufficient to meet all of its commitments under its capital program (see Note 11), and accordingly the Company will need to raise additional equity capital, debt financing or farm out portions of its property interests. In the event that additional equity or debt financing or a joint venture partner/ farm out arrangement is not obtained, $0.8 million in capital costs associated with permit AC/P 47 will be impaired.

These interim consolidated financial statements were authorized for issuance by the Board of Directors on November 9, 2012.

3. SIGNIFICANT ACCOUNTING POLICIES

a) Property and equipment – drilling rig

i) Recognition and measurement

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

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

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

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

ii) Depreciation

The net carrying value of drilling and workover rig components is depreciated using the unit of production method so as to depreciate the cost, less an estimated residual value of 20%, over the days in which the rig components are expected to be utilized during its useful life. Utilization days for depreciation purposes exclude initial mobilization, inter-well moves and final demobilization.

The estimated useful lives for certain rig components:

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

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

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

		Exploration and Evaluation Expenditures
Balance at April 1, 2011	$	7,064
Additions		10,213
Capitalized share based compensation		29
E&E impairment loss		(4,194)
Transfer to petroleum and natural gas properties		(2,705)
Exchange adjustments		119
Balance at March 31, 2012	**$**	**10,526**
Additions		8,477
Capitalized share based compensation		87
E&E impairment loss		(89)
Exchange adjustments		(238)
Balance at September 30, 2012	**$**	**18,763**

Exploration and evaluation assets consist of the Company's exploration projects in Australia and India which are pending the determination of proved or probable reserves. Costs primarily consist of acquisition costs, geological & geophysical work, seismic and drilling and completion costs until the drilling of the well is complete and the results have been evaluated.

The original time period in which to complete the seismic work program on the offshore Australia AC/P 47 permit expired on March 2, 2012. On October 19, 2012, the Company has been granted an extension to January 2, 2013 to the time period for completing the work program from the National Offshore Petroleum Titles Administrator (NOPTA). The Company is attempting to farm out this work program prior to its expiry and if unsuccessful in its efforts to farm out or obtain a further extension, then the work program will not be fulfilled and $0.8 million in costs will be impaired.

As a result of a final settlement agreement, $0.8 million of previously impaired costs on an abandoned well were recovered in the period on the statement of loss and comprehensive loss.

5. PETROLEUM AND NATURAL GAS PROPERTIES

	Petroleum and Natural Gas Properties $000s	Corporate Assets $000s	Total $000s
Cost:			
Balance at April 1, 2011	2,168	196	2,364
Additions	520	105	625
Capitalized share based compensation	2	–	2
Change in asset retirement obligation	67	–	67
Transfers from E&E assets	2,705	-	2,705
Exchange adjustments	35	-	35
Balance at March 31, 2012	**$ 5,497**	**$ 301**	**$ 5,798**
Additions	4,697	117	4,814
Capitalized share based compensation	15	–	15
Change in asset retirement obligation	64	–	64
Exchange adjustments	(83)	–	(83)
Balance at September 30, 2012	**$ 10,190**	**$ 418**	**$ 10,608**

	Petroleum and Natural Gas Properties $000s	Corporate Assets $ 000s	Total $000s
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2011	283	51	334
Depletion and depreciation charge	383	37	420
Exchange adjustments	(2)	-	(2)
Impairment expense	311	-	311
Balance at March 31, 2012	**$ 975**	**$ 88**	**$ 1,063**
Depletion and depreciation charge	156	33	189
Balance at September 30, 2012	**$ 1,131**	**$ 121**	**$ 1,252**
Net book value			
At March 31, 2012	**$ 4,522**	**$ 213**	**$ 4,735**
At September 30, 2012	**$ 9,059**	**$ 297**	**$ 9,356**

The calculation of depletion for the three months ended September 30, 2012 included $29,609,000 and $684,000 for estimated future development costs associated with proved and probable reserves in Australia and Canada respectively (March 31, 2012 - $758,000 and $684,000).

6. PROPERTY, PLANT AND EQUIPMENT

		Rig Equipment
Balance at March 31, 2011	$	–
Additions		230
Balance at March 31, 2012	**$**	**230**
Additions		4,334
Capitalized share based compensation		15
Balance at September 30, 2012	**$**	**4,579**

On April 5, 2012 the Company purchased an Ideco H-44 drilling rig. The purchase price of the Rig was US $1.75 million. Additional costs have been incurred to transport the rig from its point of purchase, prepare the rig and buy certain ancillary equipment required for drilling operations. No depreciation was recognized in the quarter as drilling did not commence until October 2012.

7. DECOMMISSIONING LIABILITIES

		September 30, 2012		March 31, 2012
Decommissioning liabilities, beginning of period	**$**	**228**	$	159
Revision		**–**		67
Additions		**64**		–
Expenditures		**–**		(3)
Accretion		**4**		5
Decommissioning liabilities, end of period	**$**	**296**	$	228

The Company's decommissioning liabilities result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning liability is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning liabilities to be $296,000 as at September 30, 2012 (March 31, 2012 - $228,000) based on an undiscounted, inflation adjusted, total future liability of $368,000 (March 31, 2012 - $283,000). These payments are expected to be made over the next 14 years with the majority of costs to be incurred between 2020 and 2026. A discount factor, being the risk-free rate related to the liability, of between 2.0% and 3.0% (March 31, 2012 – 2.0% to 3.0%) and an inflation rate of between 2.0% and 3.25% (March 31, 2012 – 2.0% to 3.0%) were used to calculate the net present value of the decommissioning liability.

8. LOSS PER SHARE

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

At September 30, 2012, there were 3,611,665 (September 30, 2011 – 2,998,667) options considered anti-dilutive.

9. FINANCIAL RISK MANAGEMENT

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 denominated in local currencies:

As at September 30, 2012 ($000s)			
	CAD	AUD	USD
Cash and cash equivalents	$ 8,923	$ 1,637	1,724
Restricted cash	135	-	-
Accounts receivable	54	651	599
Accounts payable and accrued liabilities	(1,244)	(4,132)	(834)
	$ 7,868	($ 1,844)	1,489

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 September 30, 2012, Bengal's receivables consisted of $0.6 million (March 31, 2012 - $0.6 million) from joint venture partners and $0.7 million (March 31, 2012 - $0.4 million) of other trade receivables.

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 September 30, 2012, the Company had $nil (March 31, 2012 - $0.1 million) 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 September 30, 2012 (March 31, 2012 - $nil) and did not provide for any doubtful accounts nor was it required to write-off any receivables during the quarters ended September 30, 2012 or September 30, 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.

10. CHANGES IN NON-CASH WORKING CAPITAL

Periods Ended ($000s)	September 30, 2012		September 30, 2011	
Accounts receivable	$	(298)	$	(419)
Prepaid expenses and deposits		17		(19)
Accounts payable and accrued liabilities		3,757		947
Total	$	3,476	$	509
Relating to:				
Operating	$	89	$	(789)
Financing		–		(82)
Investing		3,387		1,380
Total	$	3,476	$	509

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

The following represents the cash interest received in each period.

Quarters Ended ($000s)	September 30, 2012		September 30, 2011	
Cash interest received	$	249	$	194

11. COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. 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. See note 2 for further details with respect to financing alternatives for fulfilling these obligations.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 752	shoot 224 km² 3D seismic	December 31, 2012	$ 1.2
Offshore Australia – AC/P47	750km^2 3D seismic	January 2, 2013(2)	$7.1
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$ 3.3
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$ 5.2

(1) Translated at September 30, 2012 exchange rate of US $1.0000 = CAD $0.9833 and AUD $1.0000 = CAD $1.0204

(2) Bengal received an extension to the time period to complete the scheduled work commitment for this offshore permit from the National Offshore Petroleum Titles Administrator (NOPTA) to January 2, 2013. Refer to Note 4 for measurement uncertainty associated with this permit.

12. CONTINGENCIES

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

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)
Onshore Australia – ATP 934P	Awaiting Ministerial approval of Environmental Application before granting of ATP	4 years after grant of ATP	$ 11.9

At September 30, 2012 the Company had the following lease commitment for office space in Canada and an equipment yard in Darra, Queensland, Australia:

($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease/ Darra yard	$ 1,124	$ 251	$ 494	$ 379	$ –

Effective April 1, 2012 the Company has entered into a new head office lease in Calgary, Canada for a term of five years. Effective May 14, 2012 the Company has entered into an equipment yard lease in Darra, Australia for a rolling term of six months per term.

13. SEGMENTED INFORMATION

As at September 30, 2012, 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 include India.

Revenue reported below represents revenue generated from external customers. There were no inter-segment sales in any of the reported periods.

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

For the six months ended September 30, 2012 ($000)	Australia	Canada	New cost centres	Total
Revenue	$ 820	$ 115	$ -	$ 935
Interest revenue	75	79	3	157
Depletion and depreciation	124	65	-	189
Net earnings (loss)	591	(1,231)	(416)	(1,056)
Exploration and evaluation expenditures	5,961	-	2,516	8,477
Petroleum and natural gas property expenditures	4,802	12	-	4,814
Recovery of impairment loss	758	-	-	758
Property, plant & equipment expenditures	$ -	4,334	-	4,334

As at September 30, 2012 ($000)	Australia	Canada	New cost centres	Total
Petroleum and natural gas properties				
Cost	9,401	1,207		$ 10,608
Impairment losses	-	(311)	-	(311)
Accumulated depletion, depreciation and accretion	(528)	(413)	-	(941)
Net book value	$ 8,872	$ 483	$ -	$ 9,356
Exploration and evaluation assets	18,290	-	4,756	23,046
Accumulated impairment loss	(4,283)	-	-	(4,283)
Net book value	$ 14,007	$ -	$ 4,756	$ 18,763
Property, plant & equipment	$ -	$ 4,579	$ -	$ 4,579

For the six months ended September 30, 2011 ($000)	Australia	Canada	New cost centres	Total
Revenue	$ 2,148	$ 188	$ -	$ 2,336
Interest revenue	-	-	-	-
Depletion and depreciation	138	63	-	201
Net loss	(252)	(4,927)	(129)	(5,308)
Exploration and evaluation expenditures	3,482	-	510	3,992
Petroleum and natural gas property expenditures	348		-	348
Impairment loss	(4,340)	-	-	(4,340)

As at September 30, 2011 ($000)	Australia	Canada	New cost centres	Total
Petroleum and natural gas properties				
Cost	$ 18,554	$ 4,370	$ 451	$ 23,375
Accumulated depletion, depreciation and accretion	(15,809)	(3,604)	(451)	(19,864)
Net book value	$ 2,745	$ 766	$ -	$ 3,511
Exploration and evaluation assets	8,503	-	1,294	9,797
Accumulated impairment loss	(4,340)	-	-	(4,340)
Net book value	$ 4,163	$ -	$ 1,294	$ 5,457

CORPORATE INFORMATION

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Allens Arthur Robinson • Brisbane, Australia

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

DISCLOSURE COMMITTEE

All Directors are members of the Committee

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Stephen N. Inbusch
Robert D. Steele
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Richard N. Edgar, Executive Vice President
Bryan C. Goudie, Chief Financial Officer
D. Garrett Wilson, Vice President, Engineering and Operations
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

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