BENGAL ENERGY LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

MARCH 31, 2012

June 29, 2012

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM	million

Other

AECO	a natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
GCA	gas cost allowance
mD	millidarcy
m	metres
m^3	cubic metres
km	kilometres
km^2	square kilometres
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
$M	thousands of dollars
$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Where any disclosure of reserves data is made in this Annual Information Form that does not reflect all reserves of Bengal, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471
Kilometres Square	Acres	247.105

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta).

"**Bengal**" or the "**Corporation**" means Bengal Energy Ltd.

"**Bengal International**" or "**BEII**" means Bengal Energy International Inc., a wholly-owned subsidiary of Bengal Energy Ltd. incorporated in Alberta on February 12, 2008.

"**Bengal Shares**" or "**Common Shares**" means the common shares in the capital of Bengal.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum. (Petroleum Society) as amended from time to time.

"**DeGolyer**" means DeGolyer and MacNaughton Canada Limited.

"**DeGolyer Report**" means the report of DeGolyer dated May 8, 2012 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at March 31, 2012.

"**Gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**Management Committee**" means the committee constituted under the Production Sharing Contract between the Government of India, GAIL India Ltd., Gujarat State Petroleum Corporation Ltd. and Bengal International.

"**Net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

"**PSC**" means Production Sharing Contract.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**TSX**" or "**Exchange**" means the Toronto Stock Exchange.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being March 31, 2012.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain information regarding Bengal set forth in this document contains forward-looking statements. The use of any of the words "plan", "expect", "project", "intend", "believe", "should", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are typically intended to identify forward-looking statements. Forward-looking statements are not based on historical facts, but rather on Bengal's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental regulation and related matters, business prospects and opportunities. These statements are only predictions, not guarantees, and actual events or results may differ materially. In particular, forward-looking statements included in this document include, but are not limited to, statements with respect to: production and performance characteristics of the Corporation's oil and natural gas properties; oil and natural gas production levels and reserve resource estimates; the quantity of oil and natural gas reserves and recovery rates; the extent and results of testing and completion operations with respect to current and future wells, including with respect to the completion of the Cuisinier wells; tie in options; the Corporation's capital expenditure programs; estimated abandonment and reclamation costs and the timing thereof; supply and demand for oil and natural gas and commodity prices; drilling plans and strategy; including, without limitation the timing, location and targeted zones of current and future wells; availability of rigs, equipment and other goods and services; the utilization of the Rig in the Corporation’s drilling program; expectations regarding the Corporation's ability to raise capital and continually add to reserves through acquisitions, exploration and development; treatment under government regulatory regimes and tax laws; expected royalties that will be payable; anticipated work programs and land tenure; the granting of formal permits, licences or authorities to prospect or extensions thereof; timing of acquisitions; and the anticipated benefits of acquisitions, dispositions and the utilization of the Rig. In addition, statements relating to "reserves" or "resources" are by their nature 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.

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause actual results to vary, including but not limited to risks associated with: the impact of general economic conditions in Canada, Australia, India and globally; industry conditions including changes in laws and regulations, including the adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced, in Canada, Australia, India and globally; the level of competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities differing from management's expectations; imprecision in reserve and resource estimates; the production and growth potential of Bengal's assets; governmental regulation of the oil and gas industry; obtaining required approvals of regulatory authorities, in Canada, Australia and India; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; failure to settle native title issues where applicable; volatility in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; general risks and liabilities inherent in oil and natural gas operations; risks associated with the marketing and transportation of oil and natural gas; inability to retain drilling rigs and other services necessary to the Corporation's business; incorrect assessment of the value of acquisitions and/or the failure to realize the anticipated benefits of acquisitions; including the acquisition of the Rig; delays resulting from Bengal's inability to obtain required regulatory approvals or other consents, waivers or extensions; and other factors, many of which are beyond the control of the Corporation. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Bengal's operations and financial results are included in the section entitled “Risk Factors” in this annual information form and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

With respect to forward-looking statements contained in this document, Bengal has made assumptions regarding: the impact of increasing competition; the general stability of the economic and political environment in which Bengal operates; the timely receipt of any required regulatory approvals and extensions; the timely settlement of native title issues, where applicable; the timely execution of required contracts and agreements with appropriate government agencies; the ability of Bengal to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Bengal has an interest in to operate the field in a safe, efficient and effective manner; the ability of Bengal to obtain financing on acceptable terms; the ability of the Corporation to utilize the Rig in its drilling operations and the benefits derived therefrom; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploitation; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Bengal to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Bengal operates; and the ability of Bengal to successfully market its oil and natural gas products. Although the forward-looking statements contained in this document are based upon assumptions, which management believes to be reasonable, there can be no assurance that actual results will be consistent with these forward-looking statements, as such undue reliance should not be placed on forward-looking statements.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this document in order to provide shareholders with a more complete perspective on Bengal's current and future operations and such information may not be appropriate for other purposes. Bengal's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Bengal will derive therefrom. These forward-looking statements are made as of the date of this document and Bengal disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

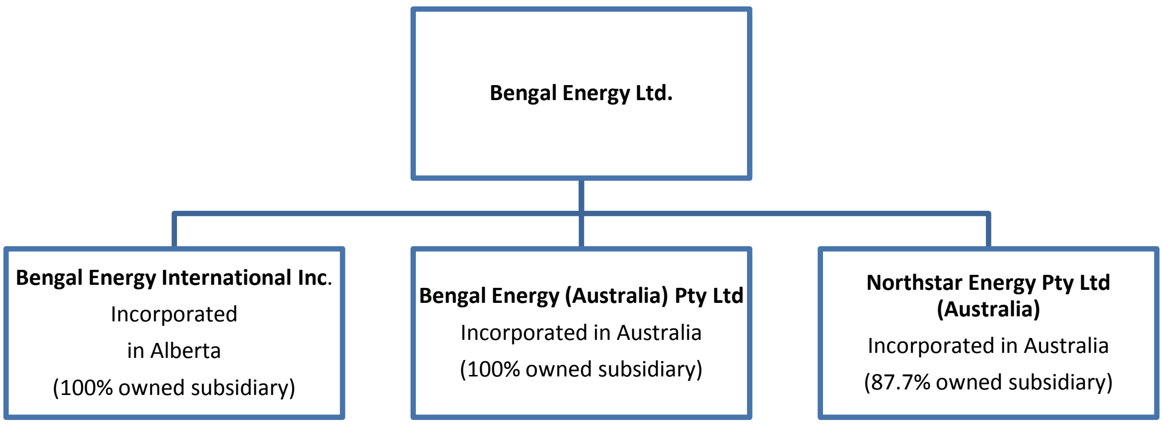
BACKGROUND AND CORPORATE STRUCTURE

The Corporation was incorporated under the ABCA on May 13, 1996, as 694460 Alberta Inc. On June 18, 1996, the Corporation filed Articles of Amendment to change the Corporation's name to Briggand Energy Corp., and on October 8, 1996 to amend its share capital and to remove the private company restrictions from its Articles of

Incorporation. Following the acquisition of Canop International Resource Ventures Inc. ("**Canop IRV**"), the Corporation changed its name to Canop Worldwide Corp. on March 11, 1997. Canop Worldwide Corp. and Canop IRV were subsequently amalgamated on April 1, 1999. On September 25, 2002 the Corporation's name was changed to Avery Resources Inc. and its outstanding shares were consolidated on a ten-for-one basis. On July 17, 2008 the Corporation's name was changed to Bengal Energy Ltd. and the shares were consolidated on a five-for-one basis.

The Corporation has its registered office at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and its head and principal office at 1810, 801 – 8th Avenue S.W., Calgary, Alberta, T2P 3W2.

The Bengal Shares trade on the TSX under the symbol "BNG".



DESCRIPTION OF THE BUSINESS AND OPERATIONS

General

Bengal is an international junior oil and gas company based in Calgary, Alberta, Canada and engaged in the business of acquiring international oil and natural gas properties and exploring for, developing and producing oil and natural gas, primarily in India and Australia. The Corporation has an active inventory of oil and gas opportunities in India and Australia and also has natural gas production in British Columbia, Canada and oil production in the Cooper/Eromanga Basin in Australia.

Corporate Strategy

The business objective of Bengal is to grow its production, reserves and resource base on a per-share basis in the international oil and gas industry, primarily in India and Australia. To accomplish this, Bengal will continue to pursue an integrated growth strategy including focused exploration, controlled exploitation, as well as strategic acquisitions within and in proximity to its primary areas of focus of India and Australia. Bengal intends to grow its resource and reserves base within its existing acreage, most of which were acquired through bid rounds in India and Australia. In addition, Bengal intends to continue to pursue its growth strategy by building strategic alliances with appropriate local partners and large operators in Bengal's primary areas of focus.

Bengal plans to pursue a balance between exploration, exploitation and development drilling. Management of the Corporation will consider asset and corporate acquisition opportunities that meet Bengal's business parameters.

While Bengal believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration and development of oil and gas has a number of inherent risks. See "*Risk Factors*" herein.

In reviewing potential drilling or acquisition opportunities, Bengal considers the following criteria:

(a) risk capital to secure or evaluate the opportunity;

(b) risked return versus cost of capital;

(c) the performance characteristics of the Corporation's oil and natural gas properties;

(d) oil and natural gas production levels;

(e) the quality of oil and natural gas reserves and recovery rates;

(f) the amount of potential for additional reservoir development;

(g) capital expenditure programs;

(h) supply and demand for oil and natural gas and commodity prices;

(i) drilling plans;

(j) availability of rigs, equipment and other goods and services;

(k) whether sufficient infrastructure exists to provide for planned activity;

(l) expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;

(m) treatment under governmental regulatory regimes and tax laws; and

(n) realization of the anticipated benefits of acquisitions and dispositions.

In addition to the above criteria, in circumstances where Bengal seeks to acquire significant assets with proven reserves, prior to the investment decision being finalized, Bengal will look to obtaining an independent engineering report (whether from the vendor of such assets or otherwise) relating to such reserves.

Bengal may approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life, immediacy of production additions, asset quality and acquisition costs.

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of the business operations of the Corporation for the periods shown.

Fiscal Year Ending March 31, 2010

Disposition of Kaybob Assets

On September 25, 2009, the Corporation disposed of non-operated production assets (the "**Kaybob Assets**") located in the Kaybob region of Alberta, Canada for aggregate gross proceeds of $2.1 million. The Kaybob Assets contributed approximately $58,000 to the Corporation's net operating income and 29 BOE/d of production for the fiscal year ended March 31, 2010. In aggregate the Kaybob Assets consisted of less than one net section of land and had been determined by management of the Corporation to be non-strategic assets.

Provisional Award of CY-OSN-2009/1 Block, Cauvery Basin, Offshore India

On October 21, 2009, the Corporation, through its wholly owned subsidiary BEII, was provisionally awarded a 100% working interest in the CY-OSN-2009/1 block (the "**CY-OSN-2009/1 Block**") by the Government of India (the "**GOI**"). The CY-OSN-2009/1 Block measures approximately 340,000 acres located in the shallow offshore area of the Southern Cauvery Basin in the State of Tamil Nadu, India.

Acquisition of ATP 732P Cooper/Eromanga Basin, Queensland, Australia

On December 11, 2009, the Corporation entered into an agreement to acquire, from its joint venture partner (the "**JV Partner**"), a 100% working interest in a an exploration block of land in Australia's Cooper/Eromanga Basin in the State of Queensland, Australia (the "**ATP 732P**"). ATP 732P measures approximately 654,000 acres. Prior to entering into this agreement the Corporation had a farm-in agreement to earn a 35% working interest in ATP 732P and following the acquisition the Corporation will hold the entire 100% working interest. The acquisition is subject to the grant of an Authority to Prospect ("**ATP**") to the Corporation from the State of Queensland, Australia. Prior to entering into the acquisition agreement the JV Partner entered into a native title agreement with the Boonthamurra people, which native title agreement is required in order to obtain authorization from the State government to commence exploration activities in the Cooper Basin Block.

Grant of Petroleum Exploration License CY-ONN-2005/1 Block, Cauvery Basin, Onshore India

On March 3, 2010, Bengal was granted a formal petroleum exploration license for CY-ONN-2005/1.

Fiscal Year Ending March 31, 2011

CY-OSN-2009/1 Block, Cauvery Basin, Offshore India

On June 30, 2010, the Corporation, through its wholly-owned subsidiary BEII, received the formal award from the GOI for the CY-OSN-2009/1 Block and entered into a production sharing contract ("**PSC**") with the GOI. The PSC sets out the terms and conditions for the exploration and development of the CY-OSN-2009/1 Block.

ATP 752P, Cooper/Eromanga Basin, Onshore Australia

Production commenced in May 2010 from the Cuisinier-oil discovery located on ATP 752P in Australia's onshore Cooper/Eromanga Basin (the "**ATP 752P")**. The Cuisinier 1 well (the "**Cuisinier 1 Well**"), which was drilled under a staged farm-in agreement (the "**ATP 752P Farm-in Agreement**") between the Corporation and all of its partners respecting ATP 752P, is located on the approximately 360,033 acre Barta sub-block (the "**Barta Sub-Block**") of ATP 752P and within the 24,958 acre Production License on the Cuisinier block **(**"**PL 303**") which is under application. The Barta Sub-Block is one of two sub-blocks that form the land covered by ATP 752P. The other sub-block is the approximately 215,723 acre Wompi sub-block (the "**Wompi Sub-Block**").

On November 12, 2010, the Barta North 1 Exploration Well ("**Barta North 1 Well**") was cased to 2,090 metres total depth by the operator of the well as a potential Murta zone oil well and, following the release of the rig on the Barta North 1 Well on November 13, 2010, Bengal increased its working interest in the Barta Sub-Block to 25% from 14.26%.

On November 26, 2010, the Cuisinier 2 appraisal well (the "**Cuisinier 2 Well**") was cased to 2,037 metres total depth by the operator of the well as a potential Murta zone oil well. The Cuisinier 2 Well is located on the Barta Sub-Block within ATP 752P and approximately 450 metres northeast of the Cuisinier 1 oil discovery. All drilling costs for the Cuisinier 2 Well were carried by the operator under the terms of the farm-in agreement relating thereto.

Australia's Cooper Basin experienced heavy rain and local flooding in December 2010 that continued through January 2011. The Cuisinier 1 Well was temporarily shut in due to road closures resulting from the flooding, which closures prevented the transportation of the Corporation's crude oil production to processing facilities. Prior to being shut-in, the Cuisinier 1 Well was producing approximately 460 barrels of oil per day (115 barrels of oil per day net to Bengal, calculated on a daily producing basis, being the average production rate for 12 producing days out of 30 days in November, 2010). Production on the Cuisinier 1 Well recommenced on January 26, 2011.

The second appraisal well on the Barta Sub-Block (the "**Cuisinier 3 Well** ") located approximately 750 metres southwest of the Cuisinier 1 Well was cased to 2,040 m total depth by the operator of the well as another potential Murta Zone oil well on March 8, 2011. The Corporation holds a 25 % working interest in the Barta Sub-Block.

ATP 732P, Cooper/Eromanga Basin, Onshore Australia

On March 13, 2011, Bengal completed the acquisition of a 100% working interest in ATP 732P pursuant to a purchase and sale agreement dated December 10, 2009. In connection with the completion of the acquisition the Department of Natural Resources and Mines of the State of Queensland, Australia made the formal grant of ATP 732P to Bengal.

General

In August 2010, Messrs. Robert Steele and Richard A.N. Bonnycastle were appointed to the board of directors of the Corporation.

In September, 2010, Bengal closed a short form prospectus offering of 12,000,000 Common Shares at a purchase price of $1.00 per Common Share for gross aggregate proceeds of $12,000,000. The offering was conducted through a syndicate of agents, led by Wellington West Capital Markets Inc. and including Macquarie Capital Markets Canada Ltd., PI Financial Corp. and Toll Cross Securities Inc.

In October, 2010, Bradley Johnson resigned as the Chief Executive Officer and as a director of the Corporation to pursue other opportunities. Following Mr. Johnson's resignation, Chayan Chakrabarty was promoted to President and Chief Executive Officer. Mr. Chakrabarty was formerly the President of the Corporation.

In January, 2011, Bengal closed a short form prospectus offering, which was conducted on a bought-deal basis, of 7,525,000 Common Shares at an issue price of $1.20 per Common Share, for aggregate gross proceeds of $9,030,000. The offering was conducted through a syndicate of underwriters led by Mackie Research Capital Corporation and including Wellington West Capital Markets Inc. and Toll Cross Securities Inc.

In February, 2011, Mr. Peter Gaffney was appointed to the board of directors of the Corporation.

Fiscal Year Ending March 31, 2012

ATP 752P, Barta and Wompi Sub-Blocks, Cooper/Eromanga Basin, Onshore Australia

At the end of August 2011 Bengal’s Cuisinier 2 and 3 wells located on the Barta Sub-Block of ATP 752P were production tested and brought on stream. Both of these Cuisinier appraisal wells were placed on pump with oil pipelined to the Cuisinier 1 lease and an expanded tank system. In July 2011, the Barta North 1 well, also located on the Barta Sub-Block, was completed as a Murta oil producer approximately 4 km from the infrastructure associated with the Cuisinier 1, 2 and 3 wells. Plans are in place that will see the Barta North 1 well tied in to the Cuisinier 1 tank system.

Bengal holds a 25% interest in the Cuisinier oil discovery, the Barta North oil discovery and the greater 360,000 acre Barta Sub-Block of exploration permit ATP 752P.

Also in August 2011 the Sampdoria well, (the "**Sampdoria Well**") was drilled onshore in the Cooper Basin on the Wompi Sub-Block (being the southern portion of ATP 752). The operator of the Wompi Sub-Block on ATP 752P paid 100% of the drilling costs of the Sampdoria Well pursuant to the Wompi Block farm-in agreement ("**ATP 752P Farm-in Agreement"**) . This well targeted oil accumulations in the Namur, Mid Namur and Basal Birkhead formations. On August 29, 2011 the operator plugged and abandoned the Sampdoria Well.

Following the drilling of the Sampdoria Well, the Corporation holds a 19.5% working interest in the approximately 215,700 acre Wompi Sub-Block. The Corporation will pay 60% of the costs of a second Wompi well by December 31, 2012 in order to complete its commitment under the ATP 752P Farm-in Agreement and increase its interest in the Wompi Sub-Block to 30%.

ATP 732P Tookoonooka Block Cooper/Eromanga Basin, Onshore Australia

The Corporation received the Ministerial Grant of Authority to Prospect 732P (**"ATP 732P**") from the Department of Natural Resources and Mines in Queensland, Australia with an effective date of April 1, 2011.

ATP 934P Barrolka Block Cooper/Eromanga Basin, Onshore Australia

In May 2012 the final Environmental Authority application for the grant of the Authority to Prospect on Barrolka Block, ATP 934P ("**ATP 934P**") was filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the final Ministerial Grant of the tenement is received. The work program consists of 500km of 2D seismic and up to seven wells.

The Corporation holds a 50% operating interest in this 361,000 gross acre permit.

AC/P 47 Block, Bonaparte Basin, Timor Sea, Offshore Australia

In November 2011 Bengal applied for an extension from March 2012 to September 2013 to the term of the large 864,000 acre offshore permit AC/P 47 from Australia's Northern Territory Government Department of Resources. The jurisdiction over the regulation of this permit changed on January 1, 2012 to the National Offshore Petroleum Titles Administration which requested further information be submitted in support of the original application. A final submission relative to the extension application for AC/P 47 was filed by Bengal on June 1, 2012. The requested extension would allow 3D seismic acquisition to be acquired, processed and interpreted prior to June 2, 2013. Assuming this extension is received, the Corporation plans to shoot, process and interpret a minimum of 750 square kilometers of 3D seismic on this permit during 2012 and Q1 2013. Bengal shall then either commit (prior to June 2, 2013) to drill a well on the permit by March 2, 2014, or, if no acceptable prospects are identified from the seismic interpretation, the permit will be relinquished.

The Corporation holds 100% working interest and operates the AC/P 47 permit that measures approximately 864,000 acres and is located off the northern coast of Australia, 150 kilometres west of the Vulcan Graben, an established offshore producing area.

AC/P 24 Block, Bonaparte Basin, Timor Sea, Offshore Australia

In October 2011 the Kingtree 1 well was drilled to evaluate a potential oil target on the 81,000 gross acre offshore exploration permit AC/P 24 in the Ashmore Cartier area, off the north coast of Australia in the Timor Sea. The Kingtree 1 well was drilled approximately 12 kilometres east of Bengal's original Katandra oil discovery. The Corporation holds a 10% working interest in Permit AC/P 24 and the Kingtree 1 well and the net costs to Bengal for the Kingtree 1 well were approximately $1 million. The well encountered significant thicknesses of reservoir sandstone in both the primary and secondary zones; however, no commercial hydrocarbons were encountered and the well has been plugged and abandoned. In December 2011 an extension request for the Kingtree Prospect and initial applications for a retention lease for the Katandra discovery were made to National Offshore Petroleum Safety and Environmental Management Authority ("**NOPSEMA**") and the National Offshore Petroleum Titles Administrator ("**NOPTA**") by the operator on the partners' behalf. Further analysis of the results of the Kingtree 1 well will be integrated into the Corporation's planning for any future exploration activity on AC/P 24 upon receipt of this extension.

CY-ONN-2005/1 Block, Cauvery Basin, Onshore India

On Bengal's non-operated 30% working interest, 233,000 gross acre CY-ONN-2005/1 block (the "**CY-ONN-2005/1**") located onshore India in the Cauvery Basin, the Corporation (and its joint venture partners Gas Authority of India Ltd. and Gujarat State Petroleum Corporation) are continuing the first year work program. Reprocessing of the existing seismic data has been completed. In September, 2011 the seismic acquisition program of 600 km2 of 3D seismic data commenced and was then suspended for late season monsoon rains. The program re-commenced in December 2011 and was increased to 700 km2. Airborne magnetometry work also began in December, 2011. The increased 3D seismic acquisition is intended to help the joint venture to accelerate the drilling of exploration wells on the block.

CY-OSN-2009/1 Block, Cauvery Basin, Offshore India

Evaluation work has continued on the 340,000 acre, 100% owned and operated Block CY-OSN-2009/1 block located in India's offshore Cauvery basin in respect of which Bengal has a 100% interest and is the operator. Activity during this first year work program included reprocessing all available seismic records and acquiring certain 2D and 3D regional surveys previously recorded by other operators. In early 2012, additional pre-existing seismic data was retrieved from government sources and integrated with the existing seismic data set. The acquisition of the additional seismic data was designed to accelerate the timing of the drilling of an exploration well. Recent acquisition activity and exploration success by competitors in the local area provides encouragement for the acceleration of the Bengal activity.

General

In April 2011, Bengal closed a short form prospectus offering, conducted on a bought-deal basis, pursuant to which it issued 14,166,800 Common Shares at an issue price of $1.80 per Common Share for aggregate gross proceeds of $25,500,240. The offering was conducted through a syndicate of underwriters led by Wellington West Capital Markets Inc. and including Mackie Research Capital Corporation and Canaccord Genuity Corp.

In August of 2011 the following persons were appointed as officers of the Corporation: Garrett Wilson, P. Eng. (Vice President, Engineering and Operations); Richard Edgar, P. Geol. (Executive Vice President); and Gordon MacMahon, P. Geol. (Vice President of Exploration). Also in August 2011, the Corporation appointed Dr. John Jackson as its Australian Country Advisor and Mr. J.L. Narasimham, as Advisor of Indian Operations. In October 2011 Mr. Bonnycastle retired from the Board of Directors.

In January 2012 the following persons were appointed as independent directors to the Corporation's Board of Directors: Mr. Stephen N. Inbusch, Dr. Brian J. Moss and Mr. Bill Wheeler. The three new directors provide additional depth in international exploration, development and financial experience to the board of directors.

Recent Developments

On April 5, 2012, Bengal acquired an Ideco H-44 drilling rig (the "Rig") and its associated equipment. The Rig is a 750 HP carrier-mounted Double with depth capabilities of 3,000 m with 3-1/2" drill pipe.As the Owner and Operator of the Rig, the Corporation plans its use initially in the exploratory drilling campaign on the ATP 732P Block located in the Cooper/Eromanga Basin of Queensland, Australia. The Corporation expects the Rig to reduce the cost structure of future drilling programs, reduce program execution risk, allow flexibility in drilling program optimization and provide program control.

The Rig was purchased for US $1.75 million with an additional US $1.0 million of capital allocated to purchase ancillary equipment, complete any required maintenance and transport the Rig from Dubai, UAE to Brisbane, Queensland. Mobilization operations are currently underway, as are efforts to procure the drilling crews required for operation.

On May 20, 2012 the Cuisinier 4 appraisal well (the "**Cuisinier 4 Well**") spud on the Barta Sub-Block portion of ATP 752P in the Cooper Basin, Queensland, Australia. The Cuisinier 4 Well, the first in the 2012 Cuisinier four well drilling campaign, located 600 metres north-west of the Cuisinier 1 discovery well is to be cased as a future oil producer. The second appraisal well Cuisinier 5, (the "**Cuisinier 5 Well**") located approximately 1,600 metres south of Cuisinier 1 was spud on June 10, 2012 and has also been cased as a future oil producer. The third well in the campaign, the Cuisinier 6 appraisal well (the "**Cuisinier 6 Well**") is expected to be drilled immediately after the Cuisinier 5 Well.

Bengal has a 25% working interest in the Barta Sub-Block portion of ATP 752P.

In April 2012, the Corporation completed the acquisition, processing and interpretation of approximately 400 line kilometres of 2D and 50 square kilometres of 3D seismic data over ATP 732P. In conjunction with this seismic data acquisition, the Corporation also completed an evaluation of aeromagnetic and gravity data on ATP 732P, and integrated such information with its seismic data evaluation.

Six potential drilling locations have been identified covering four key play types and targeting multiple zones on ATP 732P along the established southwest flank of the Cooper Basin. The Corporation has submitted an application to the Queensland Government for approval of the drilling plans on ATP 732P. The operational preparation for this drilling project has been completed, however actual timing is subject to the receipt of all regulatory approvals from the Queensland Government. The Corporation intends to deploy the recently acquired Rig for its drilling program on ATP 732P, with drilling expected to commence on the first of three locations in July 2012. Subject to the results of the first three wells, additional wells may be drilled immediately thereafter.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") has an effective date of March 31, 2012 and a preparation date of May 8, 2012.

Disclosure of Reserves Data

The Corporation engaged DeGolyer to provide an evaluation of the Corporation's proved and proved plus probable reserves as at March 31, 2012. The reserves data set forth below (the "**Reserves Data**") is based upon the DeGolyer Report. DeGolyer is an independent reserves evaluator pursuant to NI 51-101 and the COGE Handbook. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The DeGolyer Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. The Reserves Committee of the Board of Directors has reviewed and approved the DeGolyer Report. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

The Corporation's reserves are located in Canada and Australia.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF MARCH 31, 2012
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
TOTAL										
Proved Developed										
Producing	66	59	-	-	415	378	5	5	140.2	127
Non-Producing	15	13	-	-	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	**81**	**72**	**-**	**-**	**415**	**378**	**5**	**5**	**155.2**	**140**
Probable	369	329	-	-	621	423	9	6	481.5	405.5
Total Proved Plus Probable	**450**	**401**	**-**	**-**	**1,036**	**801**	**14**	**11**	**636.7**	**545.5**
CANADIAN PROPERTIES										
Proved Developed										
Producing	-	-	-	-	415	378	5	5	74.2	68
Non-Producing	-	-	-	-	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	**-**	**-**	**-**	**-**	**415**	**378**	**5**	**5**	**74.2**	**168**
Probable	-	-	-	-	621	423	9	6	112.5	76.5
Total Proved Plus Probable	**-**	**-**	**-**	**-**	**1,036**	**801**	**14**	**11**	**186.7**	**144.5**
AUSTRALIAN PROPERTIES										
Proved Developed										
Producing	66	59	-	-	-	-	-	-	66	59
Non-Producing	15	13	-	-	-	-	-	-	15	13
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	**81**	**72**	**-**	**-**	**-**	**-**	**-**	**-**	**81**	**72**
Probable	369	329	-	-	-	-	-	-	369	329
Total Proved plus Probable	**450**	**401**	**-**	**-**	**-**	**-**	**-**	**-**	**450**	**401**

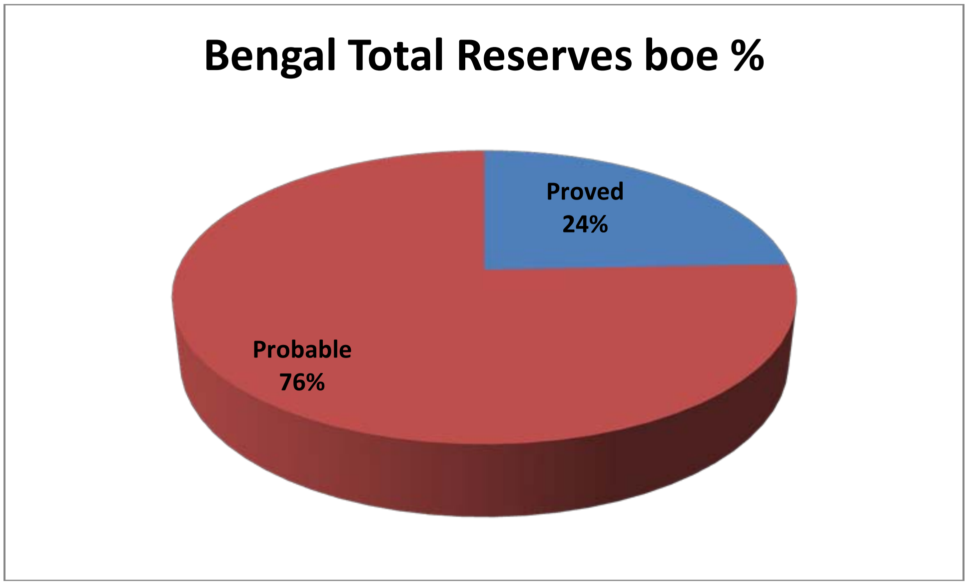
Notes:

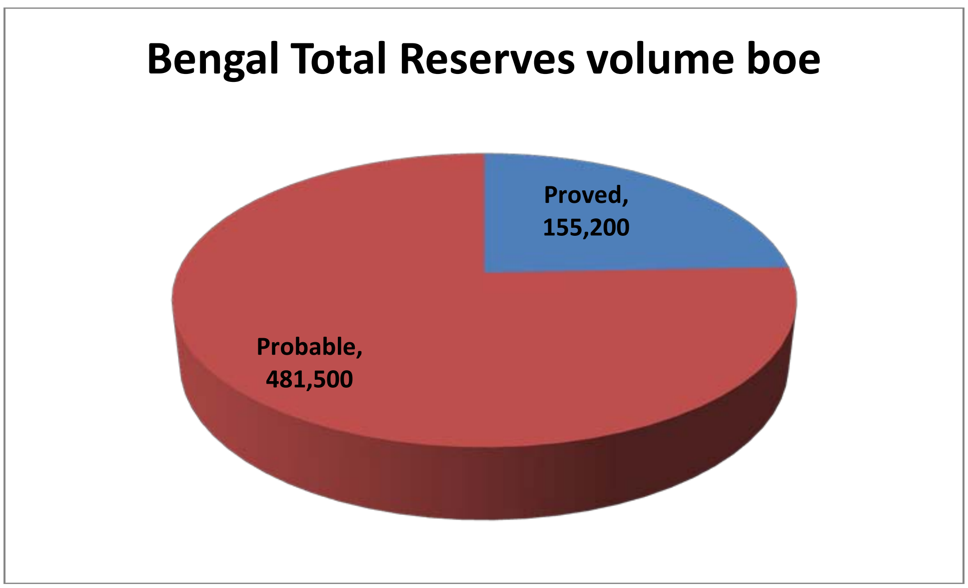
(1) Estimates of Reserves of natural gas include associated and non-associated gas.

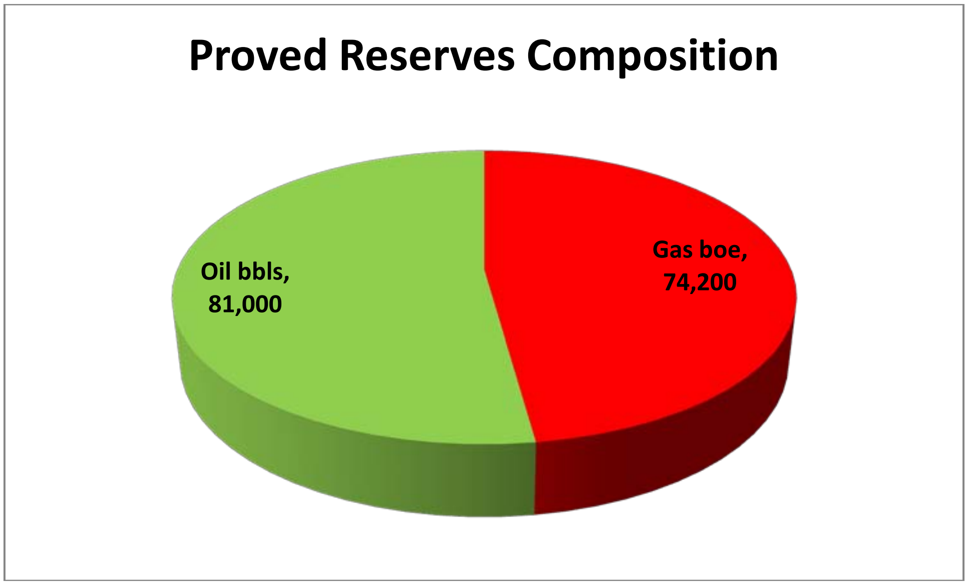
(2) "Gross Reserves" are Corporation's working interest reserves (operating and non-operating) before the deduction of royalties and without including any royalty interest of the Corporation.

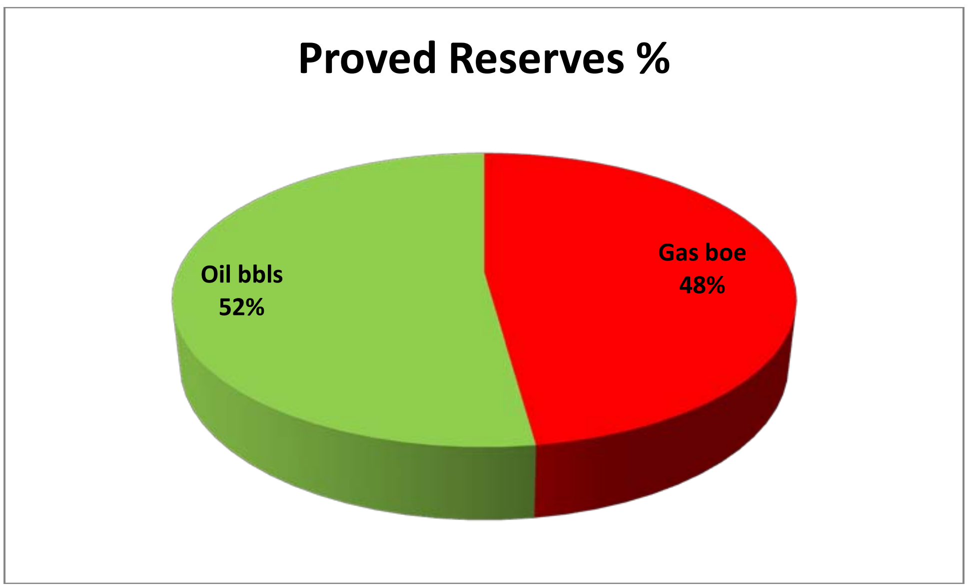
(3) "Net Reserves" are Corporation's working interest reserves (operating and non-operating) after deductions of royalty obligations plus the Corporation's royalty interests.

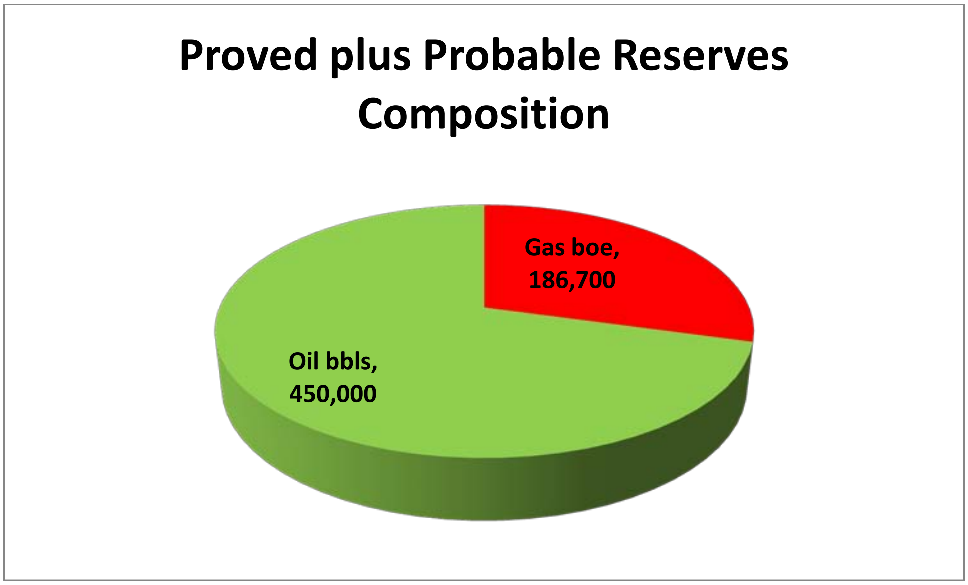
(4) The numbers in this table may not add exactly due to rounding.

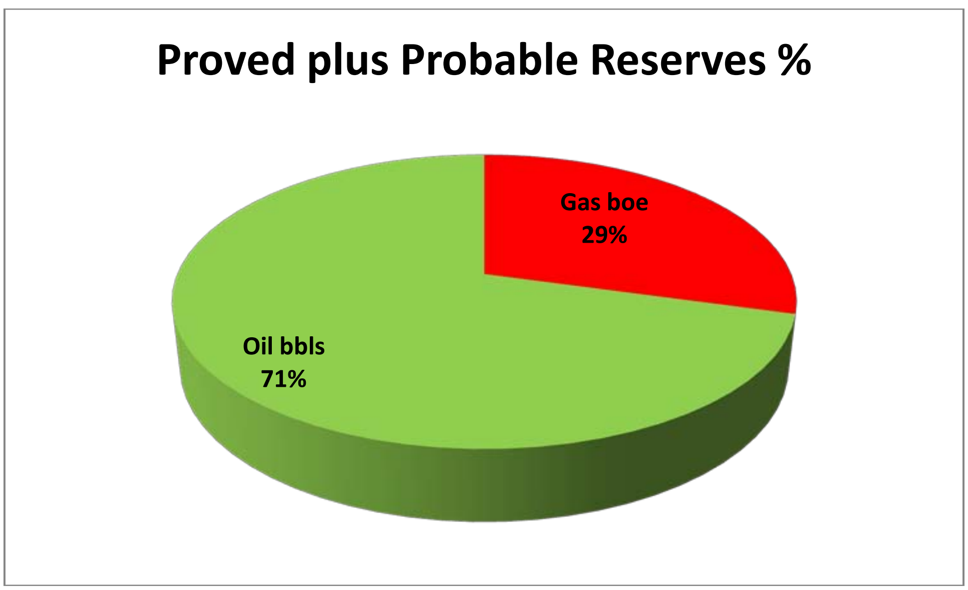

Bengal Total Reserves boe %
Proved
24%
Probable
76%


Bengal Total Reserves volume boe
Proved,
155,200
Probable,
481,500


Proved Reserves Composition
Oil bbls, 81,000
Gas boe, 74,200


Proved Reserves %
Oil bbls 52%
Gas boe 48%

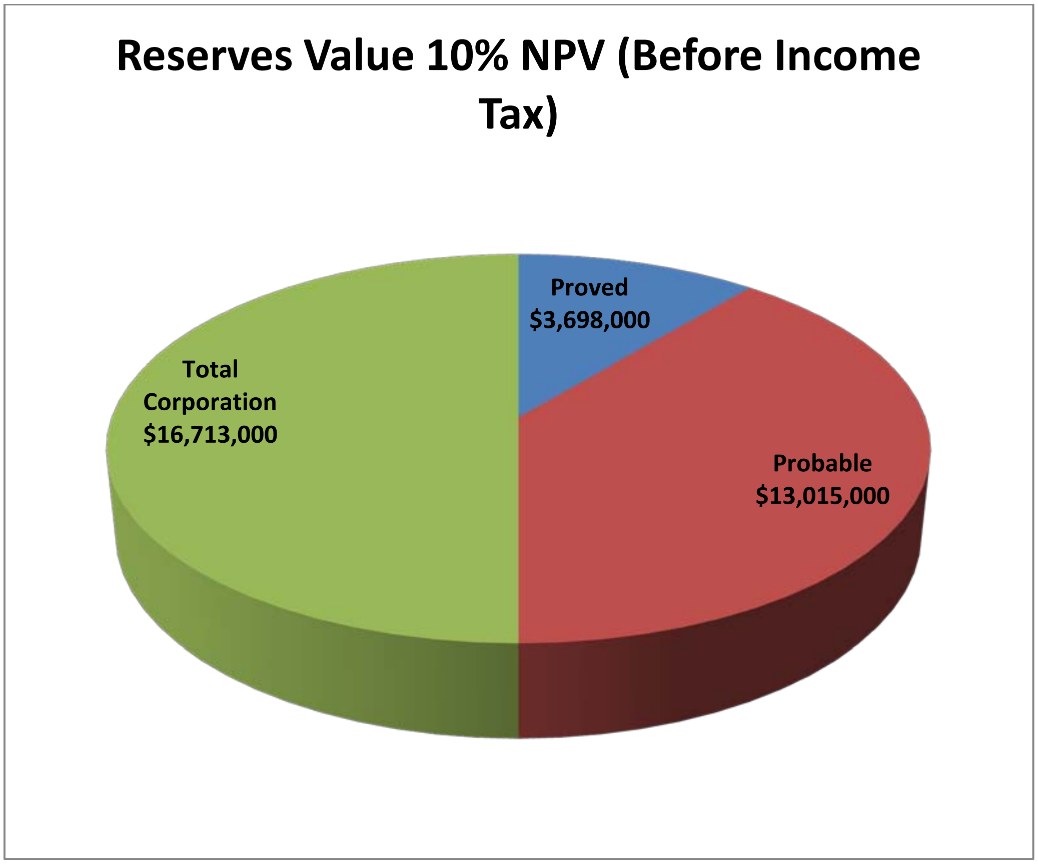

Proved plus Probable Reserves Composition
Gas boe, 186,700
Oil bbls, 450,000


Proved plus Probable Reserves %
Gas boe 29%
Oil bbls 71%

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	($/BOE)
TOTAL											
Proved Developed											
Producing	3,869	3,602	3,364	3,149	2,958	3,869	3,602	3,364	3,149	2,958	26.49
Non-Producing	396	364	334	308	283	396	364	334	308	283	25.69
Proved Undeveloped											
Total Proved	**4,265**	**3,966**	**3,698**	**3,457**	**3,241**	**4,265**	**3,966**	**3,698**	**3,457**	**3,241**	**26.41**
Probable	22,106	16,616	13,015	10,543	8,770	20,111	15,511	12,396	10,194	8,572	32.1
Total Proved Plus Probable	**26,371**	**20,582**	**16,713**	**14,000**	**12,011**	**24,376**	**19,477**	**16,094**	**13,651**	**11,813**	**30.64**
CANADIAN PROPERTIES											
Proved Developed											
Producing	359	320	286	256	231	359	320	286	256	231	4.23
Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	**359**	**320**	**286**	**256**	**231**	**359**	**320**	**286**	**256**	**231**	**4.23**
Probable	197	110	42	(10)	(51)	197	110	42	(10)	(51)	0.55
Total Proved Plus Probable	**556**	**430**	**328**	**246**	**180**	**556**	**430**	**328**	**246**	**180**	**2.27**
AUSTRALIAN PROPERTIES											
Proved Developed											
Producing	3,510	3,282	3,078	2,893	2,727	3,510	3,282	3,078	2,893	2,727	52.11
Non-Producing	396	364	334	308	283	396	364	334	308	283	25.45
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	**3,906**	**3,646**	**3,412**	**3,201**	**3,010**	**3,906**	**3,646**	**3,412**	**3,201**	**3,010**	**47.27**
Probable	21,909	16,506	12,973	10,553	8,821	19,914	15,401	12,354	10,204	8,623	39.44
Total Proved plus Probable	**25,815**	**20,152**	**16,385**	**13,754**	**11,831**	**23,820**	**19,047**	**15,766**	**13,405**	**11,633**	**40.85**

Notes:

(1) Reference Item 2.1(1) and (2) of Form 51-101F1.
(2) Net present value of future net revenue includes all resource income: sale of oil, gas by-product reserves; processing of third party reserves; and other income.
(3) Income Taxes includes all resource income, appropriate income tax calculations and prior tax pools.
(4) The unit values are based on net reserve volumes before income tax (BFIT).
(5) The numbers in this table may not add exactly due to rounding.


Reserves Value 10% NPV (Before Income Tax)
Proved $3,698,000
Probable $13,015,000
Total Corporation $16,713,000

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF MARCH 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOP-MENT COSTS (M$)	WELL ABANDON-MENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	**11,954**	**1,286**	**5,943**	**305**	**155**	**4,265**	**-**	**4,265**
Total Proved plus Probable	**61,282**	**7,369**	**25,848**	**1,443**	**251**	**26,371**	**1,995**	**24,376**
Canadian Properties								
Proved	2,198	224	1,514	-	102	359	-	359
Proved plus Probable	5,900	1,315	3,176	684	169	556	-	556
Australian Properties								
Proved	9,756	1062	4,429	305	53	3,906	-	3,906
Proved plus Probable	55,382	6,054	22,672	759	82	25,815	1,995	23,820

Notes:

(1) BT = Before Taxes and AT = After Taxes.
(2) Reference Item 2.1(3) of Form 51-101F1.
(3) The numbers in this table may not add exactly due to rounding.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF MARCH 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	3,412	$47.27
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)	286	$4.23
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	16,385	$40.85
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)	328	$2.27

Notes Regarding the Reserves Data Tables:

1. **Numbers may not add due to rounding.**

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the DeGolyer Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

3. The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Forecast Costs and Price Assumptions

4. DeGolyer employed the following pricing, exchange rate and inflation rate assumptions in estimating Bengal's reserves data using forecast prices and costs as at March 31, 2012.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (CANADIAN PROPERTIES AS OF MARCH 31, 2012)

	OIL							
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Natural Gas Alberta Spot Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butanes Price Edmonton ($Cdn/Bbl)	Inflation Rates[1] %/Year	Exchange Rate[2] ($US/$Cdn)
Forecast								
2012 (3 mo Act)	102.93	92.04	77.71	2.15	103.92	78.74	1.5	0.998
2012 (9 mo Est)	101.00	96.96	69.09	2.28	98.90	72.72	0.0	0.980
2013	102.00	97.86	69.73	3.24	99.81	73.39	2.0	0.980
2014	104.04	99.81	71.13	3.95	101.81	74.86	2.0	0.980
2015	106.12	101.81	72.55	4.48	103.85	76.36	2.0	0.980
2016	108.24	103.85	74.00	4.88	105.92	77.89	2.0	0.980
2017	110.41	105.92	75.48	5.22	108.04	79.44	2.0	0.980
2018	112.62	108.04	76.99	5.50	110.20	81.03	2.0	0.980
2019	114.87	110.20	78.53	5.79	112.41	82.65	2.0	0.980
2020	117.17	112.41	80.10	6.09	114.66	84.31	2.0	0.980
2021	119.51	114.66	81.70	6.41	116.95	85.99	2.0	0.980
2022	121.90	116.95	83.34	6.75	119.29	87.71	2.0	0.980
2023	124.34	119.29	85.00	7.10	121.67	89.47	2.0	0.980
2024+	Escalate oil, gas and product prices at 2.0% per year thereafter.							

Notes:

(1) 2012 forecast pricing is for last nine months (April 1 - Dec. 31) of 2012.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) Weighted average historical prices realized by the Corporation for the year ended March 31, 2012, were $3.77/Mcf for natural gas, $92.29/Bbl for light crude oil and $50.15/Bbl for NGLs.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (AUSTRALIAN PROPERTIES AS OF MARCH 31, 2012)

Year	**BRENT (CDN$/bbl)**	**$US/$CDN (Exchange Rate)**	**BRENT (US$/bbl)**
Historical			
2009	54.45	0.88	61.87
2010	77.73	0.971	80.05
2011	119.18	1.012	110.88
2012 (3 months actual, Jan.–Mar.)	118.44	0.998	118.70
Forecast			
2012 (9 months estimate, Apr.-Dec.)	118.37	0.98	116.00
2013	115.01	0.98	112.71
2014	112.71	0.98	110.46
2015	110.46	0.98	108.25
2016	108.24	0.98	106.08
2017	110.41	0.98	108.20
2018	112.61	0.98	110.36
2019	114.87	0.98	112.57
2020	117.16	0.98	114.82
2021	119.51	0.98	117.12
2022	121.90	0.98	119.46
2023	124.34	0.98	121.85
Thereafter escalate price at:	2.00%		

Note:

(1) Crude oil pricing has been estimated by DeGolyer as BRENT blend in Canadian dollars.

5. Well abandonment costs for wells with reserves or without reserves assigned have been included. Additional abandonment costs associated with lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. The extent and character of all factual data supplied to DeGolyer were accepted by DeGolyer as represented. No field inspection was conducted.

Reserves Reconciliation

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

(CANADIAN PROPERTIES AS AT MARCH 31, 2012)

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
March 31, 2011	**–**	**–**	**–**	**–**	**–**	**–**
Extensions	–	–	–	–	–	–
Improved Recovery	–	–	–	–	–	–
Technical Revisions[1]	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–
Acquisitions[2]	–	–	–	–	–	–
Dispositions[2]	–	–	–	–	–	–
Economic Factors[3]	–	–	–	–	–	–
Production	–	–	–	–	–	–
March 31, 2012	**–**	**–**	**–**	**–**	**–**	**–**

	NATURAL GAS LIQUIDS			NATURAL GAS			TOTAL		
FACTORS	Gross Proved (Bbl)	Gross Probable (Bbl)	Gross Proved Plus Probable (Bbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (BOE)	Gross Probable (BOE)	Gross Proved Plus Probable (BOE)
March 31, 2011	**5,894**	**6,462**	**12,356**	**638**	**700**	**1,338**	**112,227**	**123,129**	**235,356**
Extensions	–	–	–	–	–	–	–	–	–
Improved Recovery	–	–	–	–	–	–	–	–	–
Technical Revisions[1]	595	2,193	2,788	(142)	(24)	(166)	(23,072	(1,807)	(24,879)
Discoveries	–	–	–	–	–	–	–	–	–
Acquisitions[2]	–	–	–	–	–	–	–	–	–
Dispositions[2]	–	–	–	–	–	–	–	–	–
Economic Factors[3]	–	(513)	(513)	–	(55)	(55)	–	(9,680)	(9,680)
Production	(1,051)	–	(1,051)	(81)	–	(81)	(14,551)	–	(14,551)
March 31, 2012	**5,438**	**8,142**	**13,580**	**415**	**621**	**1,036**	**74,605**	**111,642**	**186,247**

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes; economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions.

(2) Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.

(3) Includes economic revisions related to price and royalty factor changes.

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

(AUSTRALIAN PROPERTIES AS AT MARCH 31, 2012)

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Bbl)	Gross Probable (Bbl)	Gross Proved Plus Probable (Bbl)	Gross Proved (Bbl)	Gross Probable (Bbl)	Gross Proved Plus Probable (Bbl)
March 31, 2011	**28,699**	**321,287**	**349,986**	**–**	**–**	**–**
Extensions	–	–	–	–	–	–
Improved Recovery	–	–	–	–	–	–
Technical Revisions[1]	82,517	47,420	129,937	–	–	–
Discoveries	–	–	–	–	–	–
Acquisitions[2]	–	–	–	–	–	–
Dispositions[2]	–	–	–	–	–	–
Economic Factors[3]	1,740	597	2,337	–	–	–
Production	(31,957)	–	(31,957)	–	–	–
March 31, 2012	**80,999**	**369,304**	**450,303**	**–**	**–**	**–**

	NATURAL GAS LIQUIDS			NATURAL GAS			TOTAL		
FACTORS	Gross Proved (Bbl)	Gross Probable (Bbl)	Gross Proved Plus Probable (Bbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (BOE)	Gross Probable (BOE)	Gross Proved Plus Probable (BOE)
March 31, 2011	–	–	–	–	–	–	28,699	321,287	349,986
Extensions	–	–	–	–	–	–	–	–	–
Improved Recovery	–	–	–	–	–	–	–	–	–
Technical Revisions[1]	–	–	–	–	–	–	82,517	47,420	129,937
Discoveries	–	–	–	–	–	–	–	–	–
Acquisitions[2]	–	–	–	–	–	–	–	–	–
Dispositions[2]	–	–	–	–	–	–	–	–	–
Economic Factors[3]	–	–	–	–	–	–	1,740	597	2,337
Production	–	–	–	–	–	–	(31,957)	–	(31,957
March 31, 2012	–	–	–	–	–	–	80,999	369,304	450,303

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes; economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions.
(2) Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.
(3) Includes economic revisions related to price and royalty factor changes.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which Bengal attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two-year time frame. The Corporation has no attributed proved undeveloped reserves as at March 31, 2012**.**

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of Bengal's three most recent financial years and before that time, in aggregate:

Year Ending March 31	Light and Medium Oil (Mbbl)	Natural Gas (MMcf)	NGLs (Mbbl)	Total (MBOE)
Prior thereto	6	982	5	175
2010	6	577	6	108
2011	6	584	5	108
2012	0	525	7	95

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

In general, once probable undeveloped reserves are identified they are scheduled into Bengal's development plans.

A number of factors could result in delayed or cancelled development plans. Such factors may include changing economic conditions due to oil and natural gas pricing, operating and capital expenditure fluctuations. Changing technical conditions resulting in production anomalies such as premature water break through or higher than anticipated production declines may result in the delay or cancellation of development plans. In wells that have encountered multiple zones, a prospective zone completion may be delayed until the initial completion is no longer economic. Larger development program may need to be spread out over several years to optimize capital allocation and facility utilization. Surface access issues associated with landowners, weather conditions or regulatory approvals could also influence development plans.

The DeGolyer Report indicates that Bengal has zero barrels of light oil, 525 million cubic feet of natural gas and 6,876 barrels of natural gas liquids reserves defined as "probable undeveloped". The change in “probable undeveloped” light oil reserves year over year results from technical, price and cost related reconciliations associated with the uphole Cadna Owie formation on the Toparoa property. All of the Probable Undeveloped natural gas and natural gas liquids (NGL’s) exist in Canada and are associated with the Oak-Cecil property in North East British Columbia. These reserves are in proposed infill and step out locations offsetting current natural gas producers. These reserves will be developed once natural gas prices return to levels that will support their economic development.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

For additional details of important economic factors or significant uncertainties that may affect the components of the reserves data in this Statement, see the Corporation's management's discussion and analysis of financial condition results of operations and cash flows for Fiscal 2012 as well as the " Risk Factors" "Principal Properties" sections herein.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
TOTAL		
2013	305	305
2014	-	901
2015	-	-
2016	-	-
2017	-	-
Thereafter	-	237
Total Undiscounted	**305**	**1,443**
CANADIAN PROPERTIES		
2013	-	-
2014	-	684
2015	-	-
2016	-	-
2017	-	-
Thereafter	-	-
Total Undiscounted	**-**	**684**
AUSTRALIAN PROPERTIES		
2013	305	305
2014	-	217
2015	-	-
2016	-	-
2017	-	-
Thereafter	-	237
Total Undiscounted	**305**	**759**

Notes:

(1) Future Development Costs shown are associated with booked reserves in the Reserves Report and do not necessarily represent the Corporation's full exploration and development budget.
(2) The numbers in this table may not add exactly due to rounding.

On an ongoing basis, Bengal will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. Bengal estimates that $305,000 will be sufficient to fund the future development costs of its proved reserves disclosed above and $1,443,000 will be sufficient to fund the future development costs of the proved plus probable reserves disclosed above. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue or make the development of a property uneconomic for the Corporation.

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada, Australia and India.

The following is a description of the Corporation's principal oil and natural gas properties as at March 31, 2012, unless otherwise stated. Production stated is gross production to the Corporation and, unless otherwise stated, is average daily production during the year ended March 31, 2012 based on operator statements. The reserve amounts stated are gross reserves, as at March 31, 2012 based on forecast costs and prices as evaluated in the DeGolyer Report (see "*Reserves Data*"). The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Oak, British Columbia, Canada

The Oak area of British Columbia is located in the Peace River Block in Townships 86 and 87-17W6. The Oak area is characterized by multi-zone, gas-prone reservoirs which include the Halfway, Baldonnel and Dunlevy/Gething formations each of which produce gas for Bengal from the property. The Corporation holds 41.9% working interest in Section 30 86-17W6M from P&NG to base of the Charlie Lake formation and 29.7% from below the base of Charlie Lake to the base of the Artex-Halfway-Doig formation. The Corporation also holds 30% working interest in Section 31 86-17W6M and 50% in Section 20 87-17W6M. As per the Dominion Land Survey, each full section is comprised of 640 acres. Additionally, Bengal has 12.2% interest in a gas compressor and related gas gathering system in the local area which offers some competitive advantage. Bengal has identified additional development and the potential for down-spacing opportunities. The Corporation currently has 3 producing gas wells. Bengal's net gas production for the year ended March 31, 2012 averaged 45 BOE/d (6:1 conversion) from the Oak property (down from 62 BOE/d from the year ended March 31, 2011).

Ashmore Cartier Area, Timor Sea, Offshore Australia

Permit AC/P47

On March 3, 2009, Bengal was awarded a 100% interest in exploration permit AC/P47. AC/P47 occupies an area of 3,485 km^2 (Bengal net 864,128 acres) in the Ashmore Cartier area of Timor Sea. The water depth averages less than 400 metres. The anticipated target reservoir zones are high quality Triassic sandstones, as demonstrated to be present by an offsetting well sitting at moderate depths ranging between 1,800 and 2,600 metres. The same Triassic sandstones are productive for oil in the adjoining Vulcan Graben.

Bengal's technical evaluation of the block, based on an existing grid of 2D seismic data, indicated the existence of substantial untested structures, some in excess of 40 km^2 in size, and with potentially in excess of 240 metres of possible closure. The existing lone well drilled in 1973 was evidenced to have been drilled largely off-structure and as such constitutes an incomplete and invalid test of the true hydrocarbon potential of the block.

AC/P47 has an initial six-year term, divided into two three-year phases. The first year of the work program (commencing on March 3, 2009) was varied under the approval of the government regulator whereby a combination of 2D seismic data was reprocessed and 300 km of new 2D seismic data was acquired. The year-one work program has been completed and the permit is currently in the third year. In years two and three, Bengal has committed to acquire and process a minimum of 750 square kilometres of new 3D seismic.

The expiry of the first phase officially occurred on March 3, 2012. During 2011, and in advance of this expiry date, Bengal was in frequent communication with the applicable regulatory body respecting the delayed progress in acquisition of the 3D seismic. Bengal is currently seeking formal approval for the variation and timing of its mandated work program for the second and third year of the work program. This will involve a suspension of the existing schedule and request for an extension allowing for enough time to acquire, process and interpret the full 3D volume well in advance of any potential drilling commitment on the permit. A formal response from the regulators and the approval of applied for changes on the timing of the work program are anticipated sometime in 2012

Subject to these regulatory approvals, and as to whether a partnership or farm-out can be arranged the Corporation will endeavour to see that the new 3D seismic survey will be acquired on AC/P47 in late 2012 or early 2013. The government approval of the applied-for adjustments to the work-program is necessary if the permit tenure is to remain valid. If the seismic is acquired in late 2012, an exploratory well can be drilled as early as Q3/Q4 2013. Following the first three-year phase, Bengal has the option to either relinquish the permit or commit to a subsequent three-year phase of work program. This second phase would involve the planning and drilling of a single offshore exploration well. The anticipated depth of this well test, as currently estimated, would be 2,600 metres from 400m water depth. To prudently manage costs throughout the expected work program, Bengal has been seeking one or more partners to help mitigate capital exposure and help the company accelerate its drilling plans on this permit.

The Corporation filed notification of being the registered titleholder of AC/P 47 as at January 1, 2012 with the newly formed Australian government departments: National Offshore Petroleum Safety and Environmental Management Authority ("**NOPSEMA**") and the National Offshore Petroleum Titles Administrator ("**NOPTA**")

This permit is subject to the reservation of a 10% royalty to the Ashmore-Cartier Territory and Petroleum Resources Rent Tax ("**PRRT**") to the Australian commonwealth.

Permit AC/P24

Bengal holds a 10% working interest in exploration permit AC/P24 ("**AC/P24**") located in the Ashmore Cartier area offshore Australia. Bengal is partnered with PTTEP Australia Timor Sea Pty Ltd. (90% working interest), the operator. Bengal's interest was earned by the drilling of a discovery oil well at Katandra-1 in December 2004. AC/P24 comprises an area of 329 km^2 (gross 81,296 acres) and is penetrated by only the single Katandra-1 well. Though successfully demonstrating that recoverable light oil exists on the Katandra structure, the gross oil column penetrated by the Katandra-1 well, being 8 metres thick at the well, is not economically viable at the present time to propose commercial development without further successful appraisal drilling. The operator applied for an extension and suspension for the term of the tenement and had it successfully extended to February 7, 2013. In addition, an application to have Blocks 3303 and 3304 containing the Katandra deposit declared a location was successfully lodged effective April 4, 2012. This allows the operator a two year period to make a further application to have these two blocks declared either a Petroleum Retention Lease or a Petroleum Production Licence. The operator proposed a new exploratory well, Kingtree-1 be drilled on permit AC/P24 to a depth of approximately 1500 m from 105 m water depth in final fulfillment of the permit's current work-term obligations. The Kingtree-1 well was drilled in September 2011 targeting a large untested structural feature located 14 km southeast of Katandra. The well found only residual evidence of hydrocarbons and was abandoned. The Kingtree-1 well came in well under budget at AUD 10 MM (net $AUD 1.0 MM to Bengal at 10% working interest). This permit is subject to the reservation of a 10% royalty to the Ashmore-Cartier Territory and Petroleum Resources Rent Tax (**PRRT**) to the Australian commonwealth. The PRRT will begin to be paid when production commences.

Cooper/Eromanga Basin, Onshore, Australia

Bengal has a very large acreage position across the onshore Cooper/Eromanga Basin of Australia approaching 2 million gross acres. Bengal's Cooper/Eromanga acreage is split among five separate blocks of land that are covered by: PEL 113, PEL 103A, ATP 732P, ATP 752P and ATP 934P.

PEL 113, Murteree, South Australia

Pursuant to the terms of a farm-in agreement, the Corporation earned a 35% interest in a 13,096 acre sub-block ("**PEL 113M**") of the larger Petroleum Exploration Licence 113 ("**PEL 113**") in the South Australian portion of the Cooper/Eromanga Basin. Bengal earned this interest by funding 3D seismic and subsequently funding the drilling of two wells operated by Stuart Petroleum Ltd. PEL 113M is operated by Senex Energy Limited (65% working interest). Bengal has production from a single oil well, called Toparoa 1, covered by Petroleum Production License (PPL) 215, issued from PEL 113. From October of 2006 the Toparoa 1 well has produced over 270,000 barrels of oil to date (32.67% net revenue to Bengal). The lands are subject to a 10% royalty to the Queensland government and a 1% royalty is reserved to the native title owners. Bengal retains the option to participate in any new wells drilled within defined area on the PEL offsetting PPL 215.

Bengal's net oil production at Toparoa for the year ended March 31, 2012 averaged 13.4 Bbls/d (up marginally from 12 Bbls/d the year before). The nearly consistent average oil rate observed in comparison to last year indicates the well has stabilized. The Corporation's interest in this land is not subject to any further work commitments at present.

PEL 103A, Aspen, South Australia

Bengal formerly participated in the drilling of two unsuccessful exploration wells on Petroleum Exploration License ("**PEL 103**") in South Australia from which Bengal earned a 25% working interest in a 13,838 acre sub-block ("**PEL 103A**") of PEL 103. In 2008, Bengal chose not to exercise its option to earn an additional 25% working interest in another small sub-block on PEL 103. Consequently, Bengal has retained a 25% working interest in PEL 103A. The majority of PEL 103A is situated across much of an ancient geological structure called the Innamincka Dome.

In 2009, the operator agreed to conduct an evaluative work program PEL 103A to test the Innamincka Dome for coal seam gas (coal bed methane) in the shallow coals of the Cretaceous Winton Formation. The operator subsequently drilled three continuously-cored, stratigraphic test holes named Merninie 1, 2 and 3. Within PEL 103A, two test holes, Merninie 2 and 3 were drilled to depths 516 m and 600 m in late October and early November 2009 respectively. The Winton coals appear to be low rank and thin in both wells. Unfortunately, the initial evaluation is that the Winton Formation is likely a sub-economic coal-seam-gas zone where it is located on the Innamincka Dome. The Corporation presently understands that no further coal seam gas evaluation is presently contemplated by the operator on the permit.

The lands are subject to a 10% royalty to the South Australia Government, a 1% royalty reserved to the native title owners along with an additional of 12% to third parties. This property does not have any production or reserves associated with it.

ATP 732P Tookoonooka, Queensland, Australia

Bengal completed the purchase of a 100% interest in ATP 732P and become the operator thereof following the formal grant of the permit by the Queensland Government in March 2011. Native title and cultural heritage agreements have already been arranged with the Boonthamurra aboriginal peoples enabling exploration activities on ATP 732P to commence. The initial four year term of the permit requires only a basic work commitment: basic geological work and seismic reprocessing, 100 km of new 2D seismic acquisition, and a single well. The ATP can be renewed twice for a total tenure period of twelve years subject to the negotiation of an additional work program. The land is subject to a 10% royalty payable on production to the Queensland government along with an added 1% royalty payable to the native title (aboriginal) persons.

Permit ATP 732P is large in size (654,335 acres) and has been tested by only eight explorations wells to date. The permit is surrounded by existing Permian gas fields and Jurassic and Cretaceous oil fields. The block therefore has good oil potential from the shallow sequence and Bengal has also identified large prospective gas in deeper Permian strata on the Permit. Thick coals interbedded with the Permian sands may also offer an associated coal-seam-gas opportunity. The center of the block was the site of what is believed to have been an ancient (Cretaceous) meteor impact structure. Such impact structures are known to be productive for oil and gas in other parts of the world.

Multiple formations are proven productive within the vicinity of the ATP 732 permit. These formations often occur as stacked reservoirs producing in the same pool. Below is a partial list of the prospective reservoirs at Tookoonooka.

The Cretaceous Wyandra Sandstone is interpreted to have been deposited in either fluvial or shore face environment with sands exhibiting porosities ranging from 12% to 33%. The Cretaceous Murta Sandstones was deposited in a meandering fluvial, overbank and lacustrine environment and the Murta sandstones are interbedded with siltstone, shale and minor coal. Sands are up to 10m thick and can be extremely variable in composition. Porosity in area wells ranges from 23% to 26%, and permeability reaches up to 65 mD.

Jurassic Westbourne, Birkhead Sandstones were deposited in a meandering fluvial, overbank and lacustrine environment, the sandstones are interbedded with siltstone, shale and minor coal. Jurassic Hutton Sandstones were deposited in a braided fluvial, environment and the Hutton sandstones are clean quartzose sandstones with well-developed porosities up to 25 percent, permeability up to 2500 mD.

Permian Toolachee sandstones are multi-zone, high-sinuosity fluvial (and overbank) deposits that range from poor to moderate quality reservoirs in the vicinity of ATP 732P. Sands are stacked and interbedded with coals and shales. Sandstone porosities in area wells range from 9% up to 21%.

In the calendar year 2011 Bengal completed a seismic acquisition program comprised of 420 km new 2D seismic and 50 km^2 of new 3D seismic, an amount greatly in excess of the actual required work commitments. This seismic has now been processed and interpreted to allow for drilling in Q3/Q4 2012. The seismic acquired was concentrated first on the Permian gas plays plus a test area where a Cretaceous oil show was identified. Three firm and three contingent drilling locations have been selected with multiple zones targeted in each location. In addition to the formations listed above Bengal believes that fractured basement is also prospective, especially in proximity to the impact site. Basement potential will be fully evaluated while drilling, with wells drilled sufficiently into basement to allow for proper assessment of its potential on the permit.

While six drilling locations have been selected a number of additional prospects have also been identified. In order to evaluate additional prospects, and to follow up on the 2012 drilling program a large second round of 2D and 3D seismic will likely be planned for in 2013. The Corporation plans to use the recently acquired Rig for this drilling program.

Marketing options for any future commercial oil and gas production from the ATP 732P permit have been investigated through an independent specialist consultant. The results of the study are currently being reviewed. These results, along with the confirmation of initial drill locations, will be utilized in the scoping and final engineering design of any production facilities and associated infrastructure that may be required to bring any commercial production to appropriate markets.

ATP 752P, Queensland, Australia

Bengal has multiple interests in ATP 752P. ATP 752P is located on the Cooper/Eromanga Basin and is subdivided into the Wompi Sub-Block (Bengal 19.5% working interest) and Barta Sub-Block (Bengal 25% working interest). However, Bengal retains the opportunity to increase its interests in the Wompi Sub-Block to 30% by drilling an option well and paying 60% of all drilling costs. Bengal has served notice of its intent to drill the Wompi option well. The option well is expected to be drilled before December 2012.

The end of the first four-year permit term of ATP 752P was July 31, 2010. The ATP 752P permit was renewed for another four year term on July 1, 2010 and is renewable for another four year term after that, subject to negotiation of new work program commitments with the governmental authority and a partial block relinquishment. Pursuant to the expiry of the initial four year term Bengal, together with its joint venture partners, relinquished 33% of the ATP 752P; the bulk of the relinquished area was assessed as poorly prospective or at least having very high exploration risk. The relinquishment does not affect any existing lead or prospects indentified by either Bengal or its partners. A new proposed work program was submitted to the applicable governmental authority, which program was planned as the minimum obligations necessary to validly hold the permit and includes additional seismic reprocessing, 50 km² of new 2D seismic acquisition and the drilling of a single exploration well. The anticipated drilling mandated under the ongoing farm-in agreement will potentially cover or exceed the proposed well commitments under the new work program. The joint venture partners are prepared, and have agreed, to accelerate activity beyond any minimal work program obligation as drilling success and results should warrant.

The Barta Sub-Block comprises 360,033 acres broken into north-eastern and south-western parcels as well as the 24,958 acre Production Licence ("**PL 303**"). The Cook oil field sits immediately east of the south-western parcel and an oil discovery (James-1) offsets the block's west boundary. Two wells drilled on the south-western parcel had oil shows. Existing and new seismic data has identified numerous, large, prospective structures on the sub-block.

Bengal increased its working interest in the Barta Sub-Block to 25% by funding 16.7% of the Cuisinier discovery well 83.3% of the second exploration well (the "**Hudson 1 Well**") and 55.0% of the third exploration well the Barta North well. The first two of the initial Barta farm-in wells were drilled in 2008. The first well, Cuisinier 1 Well, was drilled and although found to be wet in the principal target zone, discovered oil in an uphole zone called the Murta sandstone member of the Mooga Formation, a zone previously not known to be productive in the area. The second, the Hudson 1 Well, proved wet and was abandoned.

The previously equipped Barta North 1 well will be tied into the existing Cuisinier 1 facility via 4.5 km of pipeline. Construction is set to commence upon completion of the wet season in calendar year Q3 2012 with commissioning planned for the end of Q2 2012. In addition to the infrastructure work planned for Barta North 1, strategies to improve the operability and on-stream times of the existing production at Cuisinier are also being evaluated, including the potential connection of the facility at Cuisinier 1 to nearby existing infrastructure and the potential expansion of the existing Cuisinier facility to include water handling infrastructure. Further front end engineering studies are expected to commence during calendar Q3 and Q4 2012 to allow the optimal facility development strategy to be selected with the intent being to commission the upgraded infrastructure early in 2013.

In May 2010, production commenced from the Corporation's Cuisinier 1 oil discovery. The well continues to demonstrate a capability that is in excess of 350 Bbls/d oil (gross production) with no associated water. However, the Cuisinier 1 well suffered from significant shut-in periods through late calendar year 2011 and early 2012 due to the well being shut in at the request of the Department of Employment, Economic Development and Innovation ("**DEEDI**") while they review the application for a Production Licence ("**PL**"). Production is expected to re-commence in July 2012. The operator is investigating improvements in oil storage and the installation of a pipeline connecting Cuisinier to the Cook production infrastructure to the east approximately 6 kms away. The installation of this pipeline will minimize the need for trucking and decrease weather related downtime. The Cuisinier 1 Well was the first well drilled on the Cuisinier structure. The Cuisinier structure is interpreted from 3D seismic data to be one of several culminations in the area. The producing interval is the Murta Sandstone, which is well developed with 8.7 metres net pay over a 12 metre interval (1,622 to 1,634 m depth). Cuisinier 1 is located approximately six kms west of the Santos operated Cook Oil Field in southwest Queensland, near the South Australian border. The adjacent Cook Oil Field produces oil from the prolific Hutton reservoir. The Hutton zone has not yet been found to be productive at Cuisinier. Another oil discovery (James-1) offsets the block's west boundary.

Pursuant to the original farm-in agreement, the operator acquired 103 km^2 of new 3D seismic (at no cost to Bengal) surrounding the Cuisinier discovery. On the basis of this new 3D seismic, the Barta North 1 Well and the Cuisinier 2 and Cuisinier 3 Wells were successfully drilled and cased as new potential oil wells. The new wells demonstrate that the oil discovered at Cuisinier 1 may now be targeted at significant depth below the proven Murta oil zone that was perforated in Cuisinier 1. Furthermore, the Barta North 1 Well indicates that additional Murta zone prospects can be successfully targeted across a greater reservoir fairway southwest and north of Cuisinier. The operator has proposed that 125 km^2 of additional new 3D seismic be acquired to extend the partnership's existing 3D seismic coverage northward from Cuisinier. The intent is to both pursue existing and generate new exploration leads and prospects for drilling in 2013 and 2014. In collaboration with the operator, Bengal has now selected an additional four Cuisinier well locations, three are appraisal wells planned to target pool areas and to better delineate Murta reservoir quality based on seismic attribute analysis of the 3D seismic data. The fourth well, Cuisinier North 1 will target a satellite structure 2.9 kilometers north northwest of Cuisinier 1. This well will target the Murta sands as well as the Jurassic Birkhead / Hutton formations believed to be contained within a separate four way structural closure. This four well Cuisinier drilling campaign commenced in May 2012.

The Wompi Sub-Block comprises a total of 215,723 acres. Pursuant to the original farm-in agreement, the operator also has now completed the acquisition of over 200 km^2 of new 3D seismic over the Wompi Sub-Block of ATP 752P. The new 3D data (the Bowen and Genoa 3D surveys) has been processed, merged with previous 3D datasets and now interpreted by the operator. The operator indentified two principle drilling locations and drilled one of these wells (the Sampdoria Well) in 2011, under an amended farm-in agreement. Bengal's drilling costs were fully carried on this first Wompi farm-in well at Sampdoria Well, however the well was unsuccessful and subsequently abandoned. Bengal has also committed to drill one more well on the Wompi Sub-Block where Bengal will pay 60% of all drilling costs. Bengal requested to have this election well be relocated as one of the 2012 Cuisinier wells. This request was approved by the joint venture partners and the option well is now anticipated to be drilled prior to December 2012 and as a part of the current 2012 Cuisinier drilling campaign. Following the completion of the option well Bengal's working interest in the Wompi Sub-Block is expected to increase to 30%.

The land is subject to a 10% royalty payable on production to the Queensland government along with a 1% royalty reserved to the native title owners.

ATP 934P Barrolka, Queensland, Australia

Bengal and its partners were provisionally awarded a 361,268 acre onshore block of land located in the Cooper/Eromanga Basin in the State of Queensland, Australia. Bengal has a 50% working interest in the Authority to Prospect ("**ATP 934P**") block and is the operator. ATP 934P sits in the heart of the Cooper/Eromanga Basin and is surrounded by known gas fields. ATP 934P flanks the east margin of the large Barrolka gas field. Recent activity west of ATP 934P has resulted in some new oil discoveries. Bengal believes that ATP 934P is prospective for deep basin-centered and tight gas prospects. To date, five undrilled structural leads have been identified as conventional gas drilling opportunities. Bengal and its partners are negotiating a joint operating agreement to be entered into once the permit is formally awarded.

Bengal has successfully completed negotiations and entered into an agreement with the Wongkumara people regarding native title on ATP 934P. The formal grant of the permit will be made following submission of the native title agreement and the completion of an environmental assessment. The Corporation expects to complete the environmental assessment and submit the final documents late in the calendar year 2012. Upon formal grant of the permit the Corporation can commence exploration activities. The work program on ATP 934P will entail at least 500 km^2 of new 2D seismic acquisition in year one, three wells in year two, and three wells or a combination of wells and seismic through years three and four. The exploration term only begins following the execution of a native title agreement and the formal grant of the ATP by the government. The Authority To Prospect for ATP 934P can be renewed twice for a total tenure period of twelve years subject to the negotiation of additional work program. The Queensland Wild Rivers legislation that was recently enacted may compromise the original work program that was bid by Bengal. In this regard Bengal may enter into negotiation with the regulating authority relative to a revised work program.

The land will be subject to a 10% royalty payable on production to the Queensland government and management expects an additional royalty of between 1% to 1.75% subject to certain conditions will be reserved to the native title owners.

Cauvery Basin, Onshore India (CY-ONN-2005/1)

Bengal and its joint venture partners were awarded CY-ONN-2005/1 in December 2008 upon the signing of a PSC with the GOI on December 22, 2008. CY-ONN-2005/1 is located onshore in the Cauvery Basin, in the state of Tamil Nadu, India. Pursuant to a joint operating agreement, Bengal has a 30% working interest and is partnered with GSPC (30% interest) and GAIL (40% interest), the operator. CY-ONN-2005/1 measures 946 km^2 in area (233,760 gross acres). The State of Tamil Nadu awarded a petroleum exploration license in March, 2010. The permit CY-ONN-2005/1 is now currently within its second year work term. All available older 2D seismic data (732 km) has been reprocessed and additional interpretation work is underway by the operator. Under the minimum work program, 575 km^2 of new 3D seismic and 3 new exploration wells are required through the first four year phase of tenure, expiring March 2, 2014. The current year budgeted work program through to March 31, 2013, as approved by the joint venture partners, entails gross estimated expenditures of US$10.5 MM (US$ 3.2MM net to Bengal) and includes acquisition and processing of 2,300 line kilometres of aeromagnetic data, an initial environmental impact review and the expanded acquisition of 600 km^2 of new 3D seismic (including a high resolution seismic survey). Identification and drilling of prospects is now anticipated prior to the end of 2013. These lands are subject to 12.5% royalty payable to the GOI on production. Bengal itself has identified basement highs, fluvial channel systems and reefal structures in this property through its own evaluation of existing 2D seismic data and the review of analog pools in this basin.

Cauvery Basin, Offshore India (CY-OSN-2009/1)

In October 2009, Bengal bid on and was awarded 100% working interest in exploration permit CY-OSN-2009/1 located in the offshore portion of the Cauvery Basin, in the Gulf of Mannar, State of Tamil Nadu, India. The Production Sharing Contract with the GOI was formally signed in June 2010. The Indian State of Tamil Nadu granted a Petroleum Exploration License for the CY-OSN-20009/1 block in August, 2010. The permit is granted for an initial (Phase 1) term of four (4) years, with three one-year extensions being available (three years total Phase 2) afterward. A royalty payment of 10% is due to the GOI on any successful production. In the event a discovery is drilled in waters deeper than 400 metres, the royalty to the GOI is reduced to 5%. The Phase 1 (permit years 1 through 4) work program entails a minimum 310 km of new 2D seismic and 81 km^2 of new 3D seismic acquisition. Phase 2 will require one exploratory well be drilled for each extension year that the block is retained. The permit measures 340,000 acres in size and despite its large size, has been previously tested by only 3 wells. Most of the permit sits in shallow waters. Bengal has itself identified a large seismically defined structure from the older existing 2D seismic data with an aerial extent estimated to measure 10,749 acres. The second prospect lies within a previously untested sequence and covers an area of approximately 7,240 acres and has been characterized on existing 3D seismic. Bengal has carried out 2D data reprocessing which has further enhanced both structural and stratigraphic elements of the zones of interest. New 3D seismic to be acquired in late 2012 or early 2013 is aimed at identifying potential future drilling candidates. In the block immediately adjacent to Bengal's block, the operator has committed to three new exploratory wells within the permit's initial four year term. In certain circumstances, success of any of these adjacent exploratory wells on the adjoining permit may prove up plays on Bengal's own permit. During the previous twelve months Bengal has acquired all available 2D and 3D seismic data over the permit concluding a preliminary seismic interpretation. Two preliminary geological exploration models were developed late in calendar year 2011. In early 2012 detailed seismic mapping and seismic reprocessing of some 500 kms of 2D have further enhanced these preliminary models to where there are now deemed to represent valid exploration prospects. The primary targets on these prospects are within the Cretaceous Nannilam and Bhuvanigiri formations as well as the pre-Cretaceous Karoo formation.

Oil and Gas Wells

The following table sets forth the number and status of oil and gas wells in which the Corporation had a working interest as at March 31, 2012.

As at March 31, 2012, the Corporation had an interest in 8 gross (2.46 net) oil and natural gas wells as follows, all such wells are onshore wells.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Total	**3**	**0.83**	**2**	**0.5**	**3**	**1.14**	**0**	**0**
Canada	0	0	0	0	3	1.14	0	0
Australia	3	0.83	2	0.5	0	0	0	0

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at March 31, 2012.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Total	**26,458**	**15,151**	**3,139,457**	**2,254,641**	**3,166,555**	**2,269,792**
Canada	1,920	796	-	-	1,920	796
Australia	25,178	14,355	2,565,695	1,844,513	2,590,873	1,858,868
India	-	-	573,762	410,128	573,762	410,128

Note:

(1) Bengal calculates both its gross and net acres on a per lease basis.

The Corporation does not expect that any rights to explore, exploit or develop its current oil and gas acreage will necessarily expire before March 31, 2013, unless the Corporation should deem such relinquishment as appropriate or prudent.

Significant Factors or Uncertainties Relevant to Properties with No Attributable Reserves

For further information relative to economic factors and economic uncertainties that may affect the Bengal properties with no attributable reserves please refer to the "*Risk Factors*" section of this Annual Information Form.

Forward Contracts and Marketing

Although Bengal has no set policy, management of Bengal may use financial instruments to reduce corporate risk in certain situations. Risk management policies will be developed over time as Bengal builds a production base to support sustainable growth. Management will further develop a strategy over time to hedge existing liquids and natural gas production to help protect a base development capital program, guarantee a return or to facilitate financings when concluding a business transaction. Currently, Bengal has no hedging commitments due to the nature of its current asset portfolio.

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment costs related to a property have been taken into account by DeGolyer in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. The Corporation uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at March 31, 2012, the Corporation had 2.46 net wells for which it expects to incur zonal abandonment costs. The total abandonment and reclamation costs as at March 31, 2012 in respect of proved and probable reserves using forecast prices is $251,000 (undiscounted) and $128,000 (discounted at ten percent). One hundred percent of such amounts were deducted as abandonment and reclamation costs in estimated future net revenues of Bengal in respect of proved and probable reserves as disclosed above. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

Forecast Prices and Costs (MM$)	Total Proved	Total Proved plus Probable
	Abandonment Costs (Undiscounted)	Abandonment Costs (Undiscounted)
Year		
2013	13	-
2014	36	36
2015	27	-
Thereafter	79	215
Total Undiscounted	**155**	**251**
Total Discounted @ 10%	104	128

Bengal expects to pay approximately $76,000 in the next three financial years in respect of its abandonment and reclamation costs.

Tax Horizon

The Corporation does not expect to pay current income tax for the 2013 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2016 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended March 31, 2012:

	Canada (M$)	Australia (M$)	India (M$)	Total (M$)
Property acquisition costs- Proven	–	–	–	–
Property acquisition costs- Unproven	–	–	–	–
Exploration:				
Geological and Geophysical	4	5,714	1,559	7,277
Drilling	–	–	–	–
Completions	–	–	–	–
Exploration Subtotal	4	5,714	1,559	7,277
Development:				
Geological and Geophysical	–	–	–	–
Drilling	–	–	–	–
Completions	–	–	–	–
Development Subtotal	–	–	–	–
TOTAL EXPENDITURES	**4**	**5,714**	**1,559**	**7,277**

Notes:

(1) The numbers in this table may not add due to rounding.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended March 31, 2012:

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
TOTAL	**2**	**.295**	**–**	**–**
Canadian Properties				
Light and Medium Oil	–	–	–	–
Heavy Oil	–	–	–	–
Natural Gas	–	–	–	–
Dry	–	–	–	–
Service/Other	–	–	–	–
Stratigraphic Test	–	–	–	–
Total Canadian	**–**	**–**	**–**	**–**
Australian Properties				
Light and Medium Oil	–	–	–	–
Heavy Oil	–	–	–	–
Natural Gas	–	–	–	–
Dry	2	0.295	–	–
Service/Other	–	–	–	–
Stratigraphic Test	–	–	–	–
Total Australian	**2**	**0.295**	**–**	**–**

In the fiscal year ended March 31, 2012, the Corporation participated in the drilling of 2 (net 0.295) oil wells. Both were drilled and abandoned. The Sampdoria Well was drilled on the Wompi Block of ATP 752 at no cost to Bengal and was plugged and abandoned.

Offshore in the Ashmore Cartier region on AC/P-24 the Kingtree well was drilled and abandoned. Bengal participated for its 10% working interest share of this well at a cost of approximately $1,000,000.

No other drilling was undertaken. Bengal did not relinquish any exploration acreage during the fiscal year ended March 31, 2012.

Canada

No new activity occurred on the Oak property in British Columbia. Bengal sold its entire interest in the Kaybob gas property for cash consideration in September 2009.

Australia

Please see "*General Development of the Business – Fiscal Year Ended March 31, 2012*", "*General Development of the Business – Recent Developments*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*" for a summary of the current and expected exploration and development activities for Bengal's Australia properties.

In 2010, the company fulfilled its earning obligations on the Barta Sub Block by funding 55% of the cost of the Barta North 1 Well. Bengal now holds a 25% non-operated working interest in the greater Barta Sub Block and the existing Cuisinier 1 Murta-zone oil discovery. The Cuisinier 1 well began producing in May 2010 and has produced 120,000 bbls of oil as of April 30, 2012 without any appreciable water cut. At the direction of the Department of Employment, Economic Development and Innovation (DEEDI), the well was shut-in on January 13, 2012 while the approval of a Production License for Cuisinier is being sought by the Operator. Immediately prior to the shut-in, the well illustrated a capability of 250 bopd (62 bopd net to Bengal) of clean, 52^{o} API oil. The well had previously operated under annual Extended Production Tests (EPT) until the expiration of the most recent EPT on December

17, 2011. Production is stored at surface however due to the remote location, must be trucked to a pipeline terminal near Jackson for sales.

The Cuisinier 2 and Cuisinier 3 Wells were drilled offsetting the Cuisinier 1 Murta-zone oil discovery. The Cuisinier 2 Well was drilled approximately 450m northeast of the Cuisinier 1 Well and encountered three separate Murta pay sands to a depth 27m below the perforations at the Cuisinier 1 Well. Swab results from the lowest pay sand recovered 95 Bbls oil over approximately a 6 hour swab period. The upper Murta zones, including the equivalent pay zone at the Cuisinier 1 discovery, showed poor inflow and may require reservoir stimulation before they can produce. The Cuisinier 3 Well was drilled 700m southwest from Cuisinier 1. Cuisinier 3 encountered two apparent log-pay sands. Early swabbing results from the lower sand recovered a combination of oil and water. The origin and nature of the water recovery is as yet undetermined. Swabbing of the upper Murta pay sand, the equivalent to the producing Murta pay sand in Cuisinier 1, recovered 37 Bbls of oil over an approximately 5 hour period (mechanical difficulties prevented full evaluation). The swab results require further analysis. Production from Cuisinier 2 and 3 commenced in September and August of 2011 respectively, with initial combined production rates of approximately 240 bopd (60 bopd net to Bengal). Production from Barta North 1 is expected to commence August 1, 2012 after the 4.5 km pipeline tie-in is completed to the Cuisinier 1 site.

The well results at Cuisinier indicate at least a 19m gross oil column exists within the original upper Murta discovery zone. Additional deeper, lower Murta oil pay, as has been demonstrated at Cuisinier 2, looks to extend at least an additional 21m deeper. The different Murta pay zones may prove to have different oil-water contacts. Further analysis and appraisal drilling is required to determine and more fully understand the extent of the oil discovered to date. Petrophysical analysis carried out in 2011 has demonstrated that the formation water within the Murta is more saline then that of the underlying McKinley and Namur formations. There is continuous 3-4 meter thick shale often referred to as the McKinley shale, which separates the Murta from the McKinley. This shale is present in all the Cuisinier wells and in the Barta North 1 well and it is believed to potentially act as a bottom seal separating a pervasively oil saturated Murta from the water prone McKinley and Namur section.

The Barta North 1 Well was drilled approximately five km southwest of Cuisinier 1 on what was mapped as a separate structure. The well was cased by the operator as a potential oil producer with an apparent 5m gross log-pay zone. Completion and testing is expected late in calendar Q2 2011 or early in calendar Q3 2011 to verify the log results and productive capability of the well. The Barta North 1 Well demonstrates that oil has migrated through a large fairway of varying quality Murta reservoir and therefore indicates that numerous additional exploration plays and leads can be found from which to target the Murta sandstone over a very large area of the Barta Sub-Block. Detailed seismic attribute analysis of the 3D which covers Cuisinier and Barta North has provided a better understanding of reservoir sand geometry specifically within the Upper Murta sand. This analysis was used in the selection of well locations for the 2012 drilling campaign with all three appraisal wells targeting seismic amplitude expression similar to that found at the Cuisinier 1 location. Cuisinier 1 has the best developed Upper Murta sand of all wells drilled to date. The operator has proposed that an additional 125 km^2 of 3D seismic be shot in 2013 to extend the existing 3D seismic coverage northward from Cuisinier in order to pursue and generate new exploration leads and prospects.

As a condition of permit ATP 752P moving into the second of three (four year) terms, one third of the original permit area was mandatorily relinquished. However, the portion of the Barta Sub Block that was retained remains very large (1,457.1 km^2). Bengal now holds a 25% working interest in the Barta Sub-Block. The permit is valid for another eight years to July 31, 2018. The expected work commitments as applied for under the second permit term entail 100 km 2D seismic reprocessing, 50 km of new 2D seismic and a single exploration well. The government's confirmation of the application for the work program remains pending, however, the exploration activity undertaken thus far since July 31, 2010 will likely prove in excess of the required work program necessary to hold the permit in good standing.

Tookoonooka - ATP 732P

Bengal has a 100% interest in the Tookoonooka, ATP 732P permit. This permit is located on the southeast flank of the Copper Basin and covers some 654,335 acres. In 2011, the company acquired 420 kms of 2D and 50 sq kms of 3D seismic on the permit. In addition, the company acquired government areomag and gravity data across its

Queensland permits, including ATP 732P. This data was integrated with existing and newly acquired seismic to delineate prospects and define drilling locations. At this time the Corporation has identified 3 firm and 3 contingent drilling locations targeting gas in the Permian Toolachee Formation and oil in the Jurassic Hutton and Birkhead Formations as well as oil in the Cretaceous Murta and Wyandra Formations.

The ATP 732P permit is the site of a meteor impact event, which occurred in the Cretaceous approximately 125 million years ago. This impact event created numerous rim structures, which are the key targets in the 2012 drilling campaign.

AC/P47

Bengal completed its seismic reprocessing efforts and managed its first year work program regarding permit AC/P47 in the Timor Sea. Planning for a 750 km^2 new 3D survey in the second year work program has commenced, but the 3D acquisition has not been undertaken. Instead the Corporation has sought to find a partner or prospective farmee for the permit in order to mitigate the Corporation’s capital exposure and ultimately, to better possibly accelerate drilling on the permit. Bengal currently still holds a 100% working interest in AC/P47.

The permit and associated prospects were initially marketed on behalf of the Corporation by IndigoPool (Schlumberger) however a joint venture partner was not identified through this process. Late in calendar year 2011 Bengal defined an alternate exploration model on the permit which is focussed SE of the North Hibernia -1 well in an area where both Jurassic and Triassic sections are preserved and where a move favourable structural style has been identified. Additional seismic reprocessing has further supported this revamped model. The Corporation believes prospective partners will more favourably receive this new model and several companies have now been contacted to further discussions towards a potential joint venture prior to proceeding with the 3D seismic acquisition

In the meantime, Bengal has sought approval for the variation in the timing of its mandated work program by application to the Ashmore-Cartier (Northern Territory) and Australian Commonwealth regulatory authorities. Formal response from the regulators and the approval of applied for changes on the timing of the work program are anticipated now sometime in Q3 calendar year 2012. Subject to these regulatory approvals, and as to whether a partnership or farm-out can be arranged, the Corporation will endeavour to see that the new 3D seismic survey will be acquired on AC/P47 very late in calendar year 2012 or early in 2013. If the seismic is acquired in late calendar year 2012, an exploratory well could be drilled as early as Q4 in calendar year 2013.

India

Please see "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" for a summary of the current and expected exploration and development activities for Bengal's Indian properties.

CYN-ONN-2005/1

Bengal holds a 30% interest in a permit located in the onshore portion of the Cauvery Basin, in southeast India and the permit covers some 946 square kilometers. The operator of the permit GAIL is in the process of acquiring approximately 600 sq kms of 3D seismic covering most of the prospective areas on the block. In addition to the seismic the operator acquired 2300 kms of aeromagnetic data over the permit to better evaluate regional structure and to further integrate the existing 2D and new 3D seismic when it is complete.

Once the seismic acquisition is complete and the data processed and fully interpreted there will be three wells drilled later in calendar year 2013.

CYN-OSN-2009/1

Bengal has a 100% interest in offshore Cauvery permit CYN-OSN-2009/1. Located in the shallow waters of the Gulf on Mannar at the south-eastern end of India between India and Sri Lanka this permit covers 1,362 square kilometers. In the last year Bengal has acquired all available 2D and 3D seismic data over the permit concluding a preliminary seismic interpretation. Late in calendar year 2011 two preliminary geological exploration models were developed. In early 2012 detailed seismic mapping and seismic reprocessing of some 500 kms of 2D have further enhanced these preliminary models to where there are now deemed to represent valid exploration prospects. The primary targets on these prospects are within the Cretaceous Nannilam and Bhuvanigiri formations as well as the pre-Cretaceous Karoo formation.

In the fall of calendar year 2011 Cairn India subsidiary, Cairn Sri Lanka announced two gas condensate discoveries in Sri Lanka waters, approximately 50-60 kilometers southeast of Bengal's block. Subsequently Cairn has announced commerciality of their Sri Lanka permit with further activity to follow.

Bengal has now initiated the process to acquire 3D seismic on the prospects identified with data acquisition to occur late in calendar year 2012 or early 2013 depending on vessel availability. In conjunction with planning and execution of data acquisition, Bengal will be seeking a joint venture partner on the block and to this end has initiated discussions with several parties interested in the area.

Production Estimates

The following tables disclose, by product, the total volume of the Corporation's gross production estimated by DeGolyer for the fiscal year ending March 31, 2012 for year 2012.

From Gross Proved Reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Total	**84**	**-**	**281**	**4**	**135**	**100**
Canadian Properties-Oak	-	-	281	4	51	38
Australian Properties:						
Cuisinier	70	-	-	-	70	52
Toparoa	14	-	-	-	14	10

Note:

(1) The numbers in this table may not add due to rounding.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2012	2011		
	March 31	Dec. 31	Sept. 30	June 30
Average Daily Production(1)				
Total				
Oil (Bbls/d)	50	108	94	108
Natural Gas Liquids (Bbls/d)	2	4	3	2
Natural Gas (Mcf/d)	304	271	196	249
Total (BOE/d)	**103**	**157**	**130**	**152**
Canadian Properties				
Natural Gas Liquids (Bbls/d)	2	4	3	2
Natural Gas (Mcf/d)	304	271	196	249
Total (BOE/d)	53	49	36	44
Australian Properties				
Oil (Bbls/d)	50	108	94	108
Total (BOE/d)	50	108	94	108
Average Price Received (net of transportation)				
Total				
Oil ($/Bbls)	121.06	122.62	109.51	122.37
Natural Gas Liquids ($/Bbls)	77.37	60.42	50.64	72.22
Natural Gas ($/Mcf)	2.14	3.68	3.73	4.07
Total ($/BOE)	**66.80**	**92.14**	**86.20**	**94.88**
Canadian Properties				
Natural Gas Liquids ($/Bbls)	77.37	60.42	50.64	72.22
Natural Gas ($/Mcf)	2.14	3.68	3.73	4.07
Total ($/BOE)	15.29	25.20	24.76	26.62
Australian Properties				
Oil ($/Bbls)	121.06	122.62	109.51	122.37
Total ($/BOE)	121.06	122.62	109.51	122.37
Royalties Paid				
Total				
Oil ($/Bbls)	11.1	10.85	10.62	11.09
Natural Gas Liquids ($/Bbls)	17.77	15.84	14.72	15.55
Natural Gas ($/Mcf)	0.09	0.41	0.33	0.38
Total ($/BOE)	**6.02**	**8.57**	**8.54**	**8.74**
Canadian Properties				
Natural Gas Liquids ($/Bbls)	17.77	15.84	14.72	15.55
Natural Gas ($/Mcf)	0.09	0.41	0.33	0.38
Total ($/BOE)	2.03	4.11	3.09	2.08
Australian Properties				
Oil ($/Bbls)	11.10	10.85	10.62	11.09
Total ($/BOE)	11.10	10.85	10.62	11.09

	Quarter Ended			
	2012	2011		
	March 31	Dec. 31	Sept. 30	June 30
Operating Expenses				
Total				
Oil ($/Bbls)	50.56	40.35	31.81	40.65
Natural Gas and NGLs ($/BOE)	17.18	19.24	13.47	30.67
Total ($/BOE)	**33.33**	**33.71**	**26.78**	**37.77**
Canadian Properties				
Natural Gas and NGLs ($/Mcf)	2.86	3.20	2.25	5.11
Total ($/BOE)	17.16	19.20	13.50	30.66
Australian Properties				
Oil ($/Bbls)				
Transportation	42.69	17.93	17.59	17.58
Operating Expenses	7.86	22.41	14.23	23.07
Total ($/BOE)	50.55	40.34	31.82	40.65
Netback Received(2)(3)				
Total				
Oil ($/Bbls)	59.40	71.42	67.63	71.52
Natural Gas and NGLs ($/BOE)	(2.84)	2.94	8.65	(6.61)
Total ($/BOE)	**27.27**	**49.89**	**51.43**	**48.93**
Canadian Properties				
Natural Gas and NGLs ($/Mcf)	(2.84)	2.94	8.65	(6.61)
Total ($/BOE)	(2.84)	2.94	8.65	(6.61)
Australian Properties				
Oil ($/Bbls)	59.40	71.42	67.63	71.52
Total ($/BOE)	59.40	71.42	67.63	71.52

Notes:

(1) Before deduction of royalties.
(2) Amounts from physical gas contracts are included in the gas prices shown.
(3) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues. GCA is excluded.

The following table indicates the Corporation's average daily production from its important fields for the year ended March 31, 2012:

	Light and Medium Crude Oil	Heavy Oil	Gas	NGLs	BOE
	(Bbls/d)	(Bbls/d)	(Mcf/d)	(Bbls/d)	(BOE/d)
Total	**90**	**-**	**254**	**3**	**135**
Cuisinier and Toparoa	90	-	-	-	90
Oak	-	-	254	3	45

Note:

(1) Natural gas volumes are non-associated sales gas volumes.
(2) The totals shown above may not match the corporate totals due to rounding.

The Corporation's production for the year ended March 31, 2012 was 67% light quality crude oil (32° API or greater), 0% heavy oil, 31% natural gas, and 2 % liquids.

For the twelve months ended March 31, 2012, approximately 91.2% of the Corporation's gross revenue was derived from crude oil production and 8.8% was derived from natural gas and natural gas liquids production.

DIVIDEND POLICY

Bengal has not paid any dividends on outstanding Bengal Shares. The Board of Directors of Bengal will determine the actual timing, payment and amount of dividends, if any, that may be paid by Bengal from time to time based upon, among other things, the cash flow, results of operations and financial condition of Bengal, the needs for funds to finance ongoing operations and other business considerations as the Board of Directors of Bengal considers relevant. Payment of dividends is subject to the consent of the Corporation's lenders.

DESCRIPTION OF CAPITAL STRUCTURE

Bengal is authorized to issue an unlimited number of Common Shares, of which 52,110,177 are issued and outstanding as of the date hereof, and an unlimited number of preferred shares ("**Preferred Shares**"), of which none are issued and outstanding as of the date hereof. There are 3,611,667 stock options outstanding with an average exercise price of $1.14 of which 2,123,339 are vested.

The holders of Common Shares are entitled to receive notice of, to attend and vote at any meetings of the Shareholders, to receive such dividends declared by Bengal and to receive the remaining property of Bengal on dissolution after creditors of Bengal and holders of any Preferred Shares outstanding at the time have been satisfied.

The Preferred Shares are issuable in series, with each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of Bengal, whether voluntary or involuntary, the Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of each series. The Preferred Shares do not have the right to vote at meetings shareholders, except as may be provided for under applicable law.

MARKET FOR SECURITIES

Trading Price Volume

The Bengal Shares are listed and posted for trading on the TSX under the symbol "BNG". The following sets forth the price range and trading volume of the Bengal Shares (as reported by such exchange) for the periods indicated.

Period	High ($)	Low ($)	Volume
2011			
March	2.25	1.62	4,371,916
April	2.06	1.57	2,165,731
May	1.63	1.38	1,959,608
June	1.51	1.03	1,484,492
July	1.44	1.19	1,162,749
August	1.28	1.00	1,268,895
September	1.35	1.01	2,290,441
October	1.48	1.00	1,368,343
November	1.09	0.78	1,716,651
December	0.89	0.72	1,984,915
2012			
January	0.94	0.78	1,560,864
February	1.20	0.88	1,014,087
March	1.19	0.95	1,167,477
April	1.01	0.79	1,214,453
May	1.05	0.64	1,461,073
June (1-28)	0.80	0.52	635,731

Prior Sales

During the year ended March 31, 2012 Bengal issued an aggregate of 2,420,000 options to acquire Common Shares with exercise prices ranging from $1.05 to $1.32. No additional unlisted securities were issued during the year ended March 31, 2012.

Escrowed Securities

As of March 31, 2012 no securities of the Corporation were subject to escrow.

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
Chayan Chakrabarty Calgary, Alberta, Canada	President, Chief Executive Officer and Director	February 13, 2008	Appointed Chief Executive Officer of Bengal on November 26, 2010. President of Bengal since February 13, 2008. Vice President, International with Daylight Resources Trust, previously Sequoia Oil & Gas Ltd., from February 2006 to November 2007.
Ian J. Towers (3) Calgary, Alberta, Canada	Director (Chairman)	November 24, 2005	President, Chief Executive Officer and Director of Dolomite Energy Inc., a private oil and gas company, since February 2005.

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
Peter D. Gaffney [(2) (3)] Alton, Hampshire, United Kingdom	Director	January 30 2011	Independent advisor to international oil and gas industry. Director of Dominie Enterprises Ltd. from November 2005 to present. Director of Gaffney, Cline & Associates Services from 1987 to December 2009. Senior partner and Director of Gaffney, Cline & Associates Ltd. from 1963 to April 2008.
James B. Howe [(1)] Calgary, Alberta, Canada	Director	November 24, 2005	From January 1982 to present, President of Bragg Creek Financial Consultants Ltd. (a private financial consulting corporation). Mr. Howe is a Director of various public companies including Pason Systems Ltd., Ensign Energy Services Ltd., Wrangler West Energy Inc. and Holloway Lodging Real Estate Investment Trust.
Stephen Inbusch [(1) (2)] The Woodlands, Texas, USA	Director	January 6, 2012	From April 2011 to present, President of Dynamic Energy Partners and from November 2009 to present, Chief Financial Officer of Dynamic Global Advisors. Previously held position of Managing Director of CIBC World Markets from November 2005 to July 2009.
Brian Moss [(2) (3)] Calgary, Alberta, Canada	Director	January 6, 2012	June 2012 appointed Executive Vice President and Chief Operating Officer of Crown Point Ventures Ltd. and named to the Board of Directors of Crown Point Ventures Ltd. in May 2012. From January 2008 to May 2012 Executive Vice President (Latin America) of Antrim Energy Inc. Director of Antrim Energy Inc. from April 2006 to June 2012. Prior to January 2008 President and CEO of Los Altares Resources Ltd. a private oil and gas company incorporated in Alberta.
Robert Steele [(1) (3)] Calgary, Alberta, Canada	Director	August 27, 2010	Independent businessman. On the Board of Directors of Raise Production Inc. (formerly Global Energy Services Ltd.) since June, 2011. Director of Marquee Energy Ltd (formerly Skywest Energy Ltd.) since June 22, 2010. From 2001 to the May 2011 sale, a Director of Technicoil Corporation. Chairman and Chief Executive Officer of Berens Energy Ltd. from February 2002 to the sale in March 2010.
William (Bill) Wheeler [(1)] Vancouver, British Columbia, Canada	Director	January 6, 2012	Private investor. Chairman and co-founder of Leith Wheeler Investment Counsel founded in 1982. Director of Azabache Energy Inc. from June, 2010. President of Texada Capital Management, a private company since September, 2011.

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
Richard Edgar Calgary, Alberta, Canada	Executive Vice President	N/A	President of Poplar Creek Resources since July 2009. Director of Shelton Petroleum AB since December 2009. Chairman of Shelton Canada Corp. from June 1998 to Dec. 2009. Executive Chairman of Arrow Energy Ltd. from April 2008 to April 2009. Prior thereto, President of Avery Resources Inc. from November 2005 to February 2008.
Bryan Goudie Calgary, Alberta, Canada	Chief Financial Officer	N/A	Chief Financial Officer of Bengal since April 2006.
Garrett Wilson Carstairs, Alberta, Canada	Vice President, Engineering and Operations	N/A	Held various management positions at Penn West Exploration which included Development Team Manager from June 2005 to January 2009 and Production Engineering Manager from February 2009 to June 2011 prior to joining Bengal Energy Ltd.
Gordon MacMahon Calgary, Alberta, Canada	Vice President, Exploration	N/A	Vice President Exploration of Bengal since September 2011. Independent consultant to oil and gas industry March 2008 to August 2011. Vice President Exploration Trident Exploration Corp. January 2006 to Feb 2008**.**

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at June 29, 2012, the directors and officers of Bengal set forth above, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 6,642,383 Bengal Shares or approximately 12.8% of the issued and outstanding Bengal Shares and 17% on a fully diluted basis.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed herein, no director or executive officer of the Corporation: (i) is, or has been in the last 10 years, a director, chief executive officer or chief financial officer of an issuer (including the Corporation) that, (a) while that person was acting in that capacity was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days (an "**order**"), (b) was subject to an order that was issued after the proposed director ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer, (ii) is, or has been in the last 10 years, a director or executive officer of an issuer (including the Corporation) that while that person was acting in such capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (iii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver, receiver manager or trustee appointed to hold his or her assets; or (iv) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable security holder in deciding whether to vote for a proposed director.

Mr. Edgar was a director of Shelton Canada Corp. which company was listed on the TSX Venture Exchange. Shelton Canada Corp. was suspended from trading for failure to file its 2008 annual financial statements within the timeframe allowed. Shelton Canada Corp. has since filed its annual financial statements and was relisted in June 2009 and subsequently delisted January 4, 2010.

Mr. Wheeler was a director of Azabache Energy Inc ("**Azabache**") when the company was subject to a cease trade order by the Albert Securities Commission (the "**ASC**") on Nov 5, 2010 for failure to file annual audited financial statements within the time frame allowed. Azabache Energy Inc subsequently filed its annual audited financial statements and the order was lifted by the ASC on December 16th 2010.

Dr. Moss was an independent director of Richards Oil & Gas Limited which was listed on the TSX Venture Exchange when it faced severe liquidity problems in early 2010 as a result the collapse in natural gas prices, causing its senior lender to enforce its security. The Company was issued cease trade orders by the ASC, BCSC, and OSC on May 7, 2010, May 11, 2010, and May 26, 2010, respectively, for failing to make required annual continuous disclosure filings for the year ended December 31, 2009. The Company was granted protection from its creditors under the Bankruptcy and Insolvency Act ("**BIA**") on May 5, 2010. The Company's shares were de-listed from the TSXV on July 9, 2010 for failure to pay corporate sustaining fees. The Company filed a proposal under the BIA on September 24, 2010 naming Alger & Associates Inc. as the trustee, which was accepted by the Company's creditors on September 24, 2010 and the Alberta Court of Queen's Bench on October 22, 2010. The cease trade orders by the ASC and OSC were varied in December 2010 to allow certain trades as part of the proposal. After assisting the Company with its successful restructuring process, Dr. Moss, along with the rest of the Board of Directors of the Company, resigned on December 31 2010."

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The members of the Audit Committee are James Howe (Chairman), Stephen Inbusch, William (Bill) Wheeler and Robert Steele. The members of the Audit Committee are independent (in accordance with National Instrument 52-110 – Audit Committees) and are financially literate. The following is a description of the education and experience of each member of the Audit Committee.

Mr. James Howe, Chairman

Mr. Howe is a Chartered Accountant and currently serves on the Board of Directors, including Audit Committees, for various public companies. Mr. Howe graduated from the University of Western Ontario with a Bachelor of Arts (Honours) in Business Administration in 1973.

Mr. Robert Steele

Mr. Steele graduated in Electrical Engineering from the University of Saskatchewan in 1970. Mr. Steele is a professional engineer and independent businessman. He currently sits on the Board of Directors, Reserves & Environmental Health and Safety Committee and the Corporate Governance, Compensation and Nomination Committee of Marquee Energy Ltd (TSXV: MQL) (formerly Skywest Energy Ltd.). He also has been a member of the Board of Directors of Raise Production Inc. (formerly Global Energy Services Ltd.) (TSXV: RPC) since June, 2011.

Mr. Steele served on the Board of Directors for Technicoil Corporation until the May 2011 sale and also served as both Chairman of the Board and Chief Executive Officer of Berens Energy Ltd.

Mr. Stephen Inbusch

Mr. Inbusch received his Bachelor of Arts degree from Colgate University in 1971. He is currently the Chief Financial Officer of Dynamic Global Advisors and has held that position since 2009. He also has been President of Dynamic Energy Partners since April 2011. During his career, Mr Inbusch held the position of Managing Director at CIBC World Markets and other various senior positions with Canadian and U.S. banking firms and public oil and gas companies.

Mr. William (Bill) Wheeler

Mr. Wheeler holds a Chartered Financial Analyst designation and received his Bachelor of Commerce degree from the University of British Columbia in 1970. Mr. Wheeler co-founded Leithe Wheeler Investment Counsel in 1982 and currently serves as its Chairman of the Board. He also sits on the Board of Directors of Azabache Energy Inc. (TSXV: AZA) and is President of Texada Capital Management Ltd., a private company.

Pre-Approval of Policies and Procedures

Pursuant to the requirements of the Audit Committee charter, the Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services as described in the Audit Committee Mandate and Terms of Reference as set forth in Schedule "C" attached hereto.

External Auditor Service Fees

	Financial Year Ending March 2012	Financial Year Ending March 2011
Audit Fees	$115,500	$90,000
Audit Related Fees	$45,000	$78,500
Tax Fees	$42,305	$15,750
All Other Fees	$-	$-

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of The Corporation's consolidated financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) "All Other Fees" include all other non-audit services including the audit of a company acquired by us.

CONFLICTS OF INTEREST

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

HUMAN RESOURCES

As at March 31, 2012, Bengal employed 10 full-time employees and 3 part-time consultants at the head office**.** The Corporation also uses consulting services from a number of service providers on an as need basis. Bengal intends to add additional professional and administrative staff as the need arises.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, Chartered Accountants, Suite 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

Valiant Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the Bengal Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that Bengal is or was a party to, or that any of its property is or was a subject of, during the last completed financial year that were or are material to the Corporation, nor are any such material legal proceedings known to Bengal to be contemplated, that were material.

During the year ended March 31, 2012, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Corporation entered into with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding voting securities of the Corporation, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation or any of its subsidiaries.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), neither the Corporation nor any of its subsidiaries has entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than DeGolyer, the Corporation's independent engineering evaluators, and KPMG LLP, the Corporation's auditors. None of the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of National Instrument 51-102 of the Canadian Securities Administrators) of DeGolyer**]** have or are to receive any registered or beneficial interest, direct or indirect, in any of

Bengal's securities or other property of Bengal or of Bengal's associates or affiliates, either at the time DeGolyer, prepared the report, valuation, statement or opinion or any time thereafter. KPMG LLP, Chartered Accountants, the Corporation's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and foreign countries, such as India and Australia, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry**,** in the areas in which the Corporation has operations.

Pricing and Marketing

Canada:

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made, pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Australia

There is a free market for oil, condensate and liquid petroleum gas in Australia. As a result, there are no price controls and export or import approvals are not applied. Markets for crude oil and condensate exist in Australia and low-sulphur light crude oil finds a ready domestic and overseas market.

India

Under the terms of the PSCs to which the Corporation is a party, the Corporation is required to sell all of its oil to the GOI in order to meet total national demand. The oil price is determined by reference to an internationally recognized crude oil of similar properties and adjusted for differences in specific gravity and impurities. Natural gas is to be sold into the Indian domestic market at competitive fair market arm's length prices. The Corporation has the right to invest and repatriate foreign currency freely.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oilsands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Australia

In Australia taxes are payable to the Federal Government and royalties are also payable to the government of the State in which production is taking place. The principal federal taxes potentially applicable are Income Tax and the recently introduced Petroleum Resource Rent Tax (PRRT). The general income tax rate applying to corporations is 30% of taxable income where income of the Corporation is subject to the Australian tax regime. From 1 July 2012, PRRT will apply to on shore oil and gas projects (having previously only applied to off shore projects). If PRRT applies, PRRT is payable at a rate of 40% of a project's taxable profit which is determined after deducting certain project expenses (including exploration and drilling costs). PRRT payments are deductable for company income tax purposes. Credits also apply for current State royalties paid by a corporation and native title compensation. Due to significant deductions available it is generally anticipated that it would be many years into the life of a project before PRRT becomes payable. Depending on the circumstances, an excise licence and excise duty may apply to exports of crude oil once a threshold of 30 million barrels is reached and if then exceed 3 million barrels annually. A credit is allowed for the purposes of PRRT.

The current royalty imposed by State governments on oil and gas production in Australia is generally 10% of wellhead value. The royalty is based on gross revenue less an allowance for certain operating expenses and capital. The amount on which the 10% royalty is payable is generally the arm's length market price for the petroleum less operating costs that relate directly to treating, processing, refining or transporting petroleum (including wages, accommodation, catering and consumables) and less a depreciation allowance (depending on the specific regulations of the relevant State government

In onshore areas that are effected by native title (which has been recognised since the mid-1990s) additional compensation may be payable to recognized indigenous Australian title holders. This compensation is negotiable and generally varies from project to project**.** Compensation may be payable as a lump sum, by payments over time or in the form of a royalty. Native title holders do not own petroleum. Compensation payments relate to the impact of activities on traditional Aboriginal rights. Compensation is typically negotiated on a good faith basis at the beginning of a project. The Courts may determine compensation if parties can not agree or in limited circumstances may determine that a project may not proceed without the consent of native title holders.

In Australia, landholders are also entitled to compensation for the impacts of exploration or drilling activities on their land (for example, impacts on farming or grazing). Landholders do not own petroleum and are not entitled to a royalty on this basis. Compensation may be determined by the Courts if landholders and a petroleum tenement holder are not able to agree.

India

In case of onshore blocks, the royalty payable to the appropriate state government is 12.5% of the well-head value of crude oil and natural gas. For offshore blocks, the royalty payable to the GOI is 10% of the well-head value of crude oil and natural gas. A PSC with the GOI will provide, among other things, for the sharing of the production from profitable wells drilled on the basis of accumulated net income to accumulated investment as a ratio This ratio determines the portion of production attributable to the government which is determined on a year by year basis. All royalty payments paid to the GOI or a state government are included under costs that are considered allowable for cost recovery purposes under a PSC with the GOI.

Land Tenure

Canada

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The province of British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Australia

For the most part, mineral ownership in Australia is governed by the respective state governments who grant tenements for the exploration of petroleum and natural gas. While not exactly the same, largely the process from state to state is similar. Oil and gas companies typically submit applications to the applicable state government for exploration permits or an ATP in response to invitations to bid made in government gazettals (onshore and offshore). Within the applications, companies outline a schedule of work programs which include both an estimate of the financial commitments to be spent on the property(s) year over year along with a certain amount of seismic and/or exploration wells to be drilled. Depending on the location of the permit, state governments will award the permits subject to the Corporation successfully negotiating native title agreements with Aboriginal surface owners. After a successfully negotiated native title agreement, the Corporation is then formally granted the ATP or exploration permit by the State. The permits typically provide the Corporation with at least four (4) years and in some States, up to a maximum of 12 years to conduct its proposed work program with the opportunity for potential extensions. Generally, each state government will reserve unto itself a royalty when production commences which runs with the life of the relevant Production Licence (see comments above). It should also be noted that for each ATP or exploration permit issued there is a minimum work program which the applicable state authority expects to be met or exceeded. If the minimum work commitment set forth in the work program is not completed then there is a risk that the ATP or exploration permit is terminated. In most States a small amount is payable by way of annual fee or rent. Failure to pay may also result in termination.

In most cases ATP's held by the Corporation are granted for a period of twelve years. Where the ATP has an initial term of twelve years, this period may be subdivided into three, four year periods. During the first four year period, work commitments are completed and at the end of the period one third of the land that was originally granted must be relinquished back to the state. Following such relinquishment the next four year period commences and at the end of the last period remaining land must be relinquished. Alternatively, the conditions of an ATP may require relinquishment of 8.33% of area per year over a 12 year period. Generally at the end of the twelfth year, all of the land will have been relinquished that has not been a part of a commercial discovery. Commercial discoveries are held under 'Production Licenses' which are exempt from relinquishment and stay active until final field abandonment or the end of the specified term of the Production Licence (generally 30 years). *India*

The oil and gas industry in India is subject to extensive regulations governing its operations including land tenure, exploration, development, production, refining, transportation and marketing through legislation enacted by various levels of government. Although the GOI has ultimate ownership and responsibility for oil and gas operations, various state governments also have input into industry activities. During the past several years, the GOI regulations have been revised to include tax holidays and permit foreign ownership levels of up to one hundred percent in the Indian oil and natural gas industry. In response to invitations to bid made by the GOI through the New Exploration Licensing Policy ("**NELP**") bid rounds in India, domestic and international oil and gas companies submit bids to win tenements for the exploration of petroleum and natural gas. Within the bid applications, companies outline a schedule of work activities along with an estimate of associated financial commitments on each tenement on an annual basis; in addition, companies submit a fiscal package which offers the economic terms under which a company would operate the tenement. The fiscal or economic terms and the duration of the land tenure are confirmed at the time of signing a PSC between a company and the GOI. Most PSCs in India grant the companies 20-25 year tenure with a provision for up to two 5 year extensions.

There is usually an initial exploration period and at the end of it and after having conducted a minimum work program the company may relinquish its entire interest or continue with a subsequent exploration period. As in Australia, commercial discoveries are held through the production phase and no relinquishments are required.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

The Corporation is subject to significant environmental and other regulations in respect of its exploration activities in Australia and India and has tried to earnestly undertake its operations in an environmentally responsible manner and to maintain compliance with the relevant regulations. Rehabilitation of individual field projects is completed progressively to ensure necessary rehabilitation restoration is kept to a minimum at any particular time.

In Australia the Queensland Wild Rivers legislation that was recently enacted regulates new development and the taking of natural resources from within a declared wild river and its catchment area. Wild river areas are relatively untouched areas in near natural condition with all or also most all of their natural values intact. To preserve these river systems Wild River Areas have been declared. A wild river declaration means extra protection for the river system. From nomination to potential declaration as a wild river, there is a lengthy process of consultation between the Queensland Government and residents, businesses and interested parties. All parties have an opportunity to submit any issues or views about proposed wild rivers. All issues and views raised are considered before a final decision on a declaration is made.

The Wild Rivers legislation may compromise the original work program that was bid by Bengal on its ATP 934 as well as drilling operations on parts of the Corporations ATP 732. In this regard Bengal may enter into negotiation with the regulating authority relative to a revised work program and will stay committed to understanding and supporting the Wild Rivers legislation intent and purpose.

Management is satisfied that no material breaches of the environmental legislation have occurred with respect to any of the Corporation's properties. No notices of any material breaches have been received from any authority by the Corporation.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011, Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 BOE/d/company. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities were able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide omissions from coal fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

To the knowledge of the Corporation, there is no ownership or working interests in facilities that are subject to reporting/verification requirements.

Australia

In Australia, the Federal Government is implementing the Clean Energy Futures package, a set of measures aimed at reducing greenhouse gas emissions and increasing the use of renewable energy. The package includes a carbon pricing mechanism, which from 1 July 2012 will impose a price on emissions of greenhouse gases.

The carbon pricing mechanism applies to four of the six greenhouse gases covered by the Kyoto Protocol. Most sectors are included, other than agriculture, which instead is given an incentive to undertake projects to reduce or store emissions. Most sectors are covered by an emissions trading scheme established under the Clean Energy Act 2011, other than transport, where an equivalent carbon price will be applied through reductions to fuel excise and rebate arrangements.

In the first three years, the emissions trading scheme operates as a tax, after which it moves to a conventional cap-and-trade model. Broadly, two activities give rise to liability under the emissions trading scheme. The first is having operational control of a facility (defined as an activity or series of activities forming a single undertaking or enterprise) with annual emissions of at least 25,000 tonnes (measured in CO2 equivalent). The second is being a supplier of natural gas for use, where the gas is withdrawn from a natural gas pipeline for the purposes of the use. There is also an opt-in mechanism, principally intended for the aviation sector, and some limited flexibility to transfer liability. Unincorporated joint ventures are covered by rules that enable liability to be allocated to the joint venture participants. The scheme includes some flexibility to transfer liability.

In the case of facilities, liability is based on direct emissions from the facility, such as emissions from the combustion of gas or coal. For gas suppliers, liability is based on the potential emissions embedded in the gas they supply. Emissions from large gas consuming facilities such as power stations are captured under the facilities mechanism, rather than through the gas supplier.

For each tonne of emissions, a liable entity must either surrender one eligible emissions unit, or pay the shortfall charge. The charge is set high enough for there to be a strong incentive to buy and surrender units.

The price for carbon units is fixed for the first three years of the scheme, initially at AUD $23 per unit. During that first phase, carbon units are available in unlimited quantities. From 1 July 2015, the scheme enters the flexible price phase. The scheme's regulator will issue carbon units by auction and the total number of carbon units will be capped at a level to be set by Government. For at least the first three years of the flexible price phase, auctions will be subject to a price ceiling, initially AUD $20 per unit above international prices. A price floor will also apply, being initially AUD $15.00 per unit.

The carbon pricing mechanism is linked to Australia's Carbon Farming Initiative (CFI), a scheme for land based projects to reduce or store greenhouse gas emissions and earn tradeable credits. Liable entities will be able to use eligible credits from the CFI for up to 5% of liability in the fixed price phase and in unlimited quantities after that.

As to international markets, some classes of international units will also be eligible for surrender, but only in the flexible price phase and, at least initially, only for up to 50% of liability. International units will also be subject to a surrender charge to ensure the effective price is equivalent to the auction floor price.

India

On June 30, 2008, Prime Minister Manmohan Singh released India's first National Action Plan on Climate Change (NAPCC) outlining existing and future policies and programs addressing climate mitigation and adaptation. The plan identifies eight core "national missions" running through 2017 building on the Energy Conservation Act 2001

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits or not be covered, in which event the Corporation could incur significant costs.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Risks Associated with Foreign Operations

International operations are subject to political, economic and other uncertainties including, among others, risk of war, risk of terrorist activities, border disputes, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labour disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Corporation's international operations. With respect to taxation matters, the governments and other regulatory agencies in the foreign jurisdictions in which Bengal operates and intends to operate in the future may make sudden changes in laws relating to taxation or impose higher tax rates which may affect Bengal's operations in any significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductable under applicable laws or may have differing views as to values of transfer properties. This can result in significantly higher tax payable than initially anticipated by Bengal. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Bengal which can result in the Corporation having to pay significant penalties and fines. The Corporation's international operations may also be adversely affected by laws and policies of Canada and the United States and other jurisdictions affecting foreign trade, taxation and investment. For example, the Corporation may be at a disadvantage in that it may be required to compete against corporations or other entities from countries that are not subject to Canadian laws and regulations, including the *Foreign Corrupt Practices Act* or similar legislation in other jurisdictions, including the United States. Residents or nationals of countries not subject to such legal regimes may offer inducements to foreign public officials to entice such governments and officials to deal with them to the disadvantage of the Corporation. Furthermore, in the event of a dispute arising from international operations, the Corporation may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada. The Corporation operates in such a manner as to minimize and mitigate its exposure to these risks; however, there can be no assurances that Bengal will be successful in protecting itself from the impact of all of these risks.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, North Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. The market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of the common shares of the Corporation that are unrelated to the Corporation's performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which the common shares of the Corporation will trade cannot be accurately predicted.

Variations in Foreign Exchange Rates and Interest Rates

Bengal receives Canadian dollars for gas sales from its Oak property. These Canadian dollars are then expended on operations and administration in Canada. The Corporation's expenses on Canadian operations are denominated in Canadian dollars and the Corporation's operating income is therefore not generally impacted by the Canadian to US dollar exchange rate.

The exchange rate for the Australian dollar has strengthened against the Canadian dollar throughout the year. Bengal, through its subsidiary Bengal Energy (Australia) Pty Ltd., received revenue from Australian oil sales in US dollars. These US dollars are then converted to Australian dollars and remain in Australian dollars until expended on operations or capital in Australia and therefore the Australian dollar to Canadian dollar exchange rates do not materially impact the Corporation's overall profitability. Historically, declines in world oil prices which are denominated in US dollars have been offset by increases in the value of the Australia versus the US dollar. As a result, Bengal's Australian netbacks are not overly affected by the Australian dollar to US dollar exchange rates.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. As a result of the global economic volatility, the Corporation, along with many other oil and natural gas entities, may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, possible future borrowings and equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of the capital markets, the Corporation's credit rating (if applicable), interest rates, tax burden due to new tax laws and investor appetite for investments in the energy industry and the Corporation's securities in particular. Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Some of Bengal's oil and gas interests are in offshore properties. Offshore operations involve a significant degree of risk including all of the risks associated with all petroleum operations which can be magnified due to operating in remote offshore locations. Fires and explosions on drilling rigs and other offshore platforms are more likely to result in personal injury, loss of life and damage to property due to the remote locations and time required for rescue personnel to get to the locations. Blow-outs and spills are more likely to result in significant environmental damage to the marine environment, can be difficult to contain and difficult and expensive to remediate. Although Bengal intends to operate in accordance with all recommended and required health, safety and environment practices, which will reduce such risks, there can be no assurance that these risks can be avoided. The occurrence of any of these events could have a materially adverse effect on the Corporation.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Bengal has entered into agreements with respect to various permit areas in Australia. The formal grant of some of these permits by Australian government authorities is conditional on and subject to the successful conclusion of Native Title negotiations. Accordingly, there is a risk that the native claims may not be resolved and the permits may not be issued.

There are no such aboriginal claims in India.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Australia

All phases of the oil and gas exploration, development and production activities are regulated in varying degrees by the Australian Federal government and relevant State government, either directly or through one or more governmental entities. The areas of government regulation include matters relating to restrictions on production, , income taxes, PRRT, royalties, expropriation of property, environmental protection, land access, rig safety, workplace health and safety and fair employment conditions. In addition, the award of an ATP or PEL and matters relating to the implementation and conduct of operations under these agreements are subject to the consent of the relevant government. Generally all future drilling and production programs by the Corporation in Australia must also be approved by or be subject to review by the Australian Federal government and relevant State governments. This regulatory environment and possible delays inherent in that environment may increase the risks associated with the Corporation's exploration and production activities and increase the Corporation's costs of doing business.

India

All phases of the oil and gas exploration, development and production activities are regulated in varying degrees by the Indian government, either directly or through one or more governmental entities. The areas of government regulation include matters relating to restrictions on production, price controls, export controls, income taxes, expropriation of property, environmental protection and rig safety. In addition, the award of a PSC and matters relating to the implementation and conduct of operations under the PSC are subject to Government of India consent. As a consequence, all future drilling and production programs and by the Corporation in India must be approved by the Indian government. This regulatory environment and possible delays inherent in that environment may increase the risks associated with the Corporation's exploration and production activities and increase the Corporation's costs of doing business.

The Corporation and its partners are required under the NELP fiscal regime to submit annual expenditure budgets to the Government of India for approval on all Indian fields and blocks. Expenditures in excess of the budget are subject to approval by the Government of India. In the case of cost over-runs, those expenditures not ratified by the Government of India, the allowable expenditure limit for any given year may be reduced and this would affect the investment multiple, potentially affecting the petroleum profit share calculation.

The Corporation will be required to submit a bank guarantee of the first year's estimated expenditure.

The Corporation has performance security guarantees to the Government of India. The Government of India has the right to collect on the guarantees if the Corporation does not carry out the work commitment required under the various concession agreements (PSC's).

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In both India and Australia the level of activity and production may be influenced by seasonal weather fluctuations such as, but not limited to, flooding and monsoons. During these flooding and monsoon events it is usual that access roads and oil hauling roads are impacted for periods of time with the resulting down time for oil production activities. In Australia, access to roads and properties may be restricted or prohibited during times of severe flooding. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that existing or newly enacted environmental laws and regulations will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title to the oil and natural gas properties that the Corporation controls that, if successful, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

India

The PSCs contain certain terms that may affect the revenues and create additional risks for the Corporation. These terms include, possibly among others, the following:

- The Corporation and its partners are required to complete certain minimum work programs during the three or four year phases of the terms of the PSCs. In the event the venture participants fail to fulfill any of these minimum work programs, the Corporation and its partners must pay to the Government of India their proportionate share of the amount that would be required to complete the minimum work program. Accordingly, the Corporation could be called upon to pay its proportionate share of the estimated costs of any incomplete work programs.

- Until such time as the Government of India attains self sufficiency in the production of crude oil and condensate and is able to meet its national demand, the Corporation and its partners are required to sell in the Indian domestic market their entitlement under the PSCs to crude oil and condensate produced from the exploration blocks. In addition, the Indian domestic market has the first call on natural gas produced from the exploration blocks and the discovery and production of natural gas must be made in the context of the government's policy of utilization of natural gas and take into account the objectives of the government to develop its resources in the most efficient manner and promote conservation measures. Accordingly, this provision could interfere with our ability to realize the maximum price for our share of production of hydrocarbons.

- The Corporation, which is not an Indian company, is required to negotiate technical assistance agreements with the Government of India or its nominee whereby such foreign company can render technical assistance and make available commercially available technical information of a proprietary nature for use in India by the government or its nominee, subject, among other things, to confidentiality restrictions. Although not intended, this could increase the Corporation's cost of operations.

- The Corporation and its partners are required to give preference, including the use of tender procedures, to the purchase and use of goods manufactured, produced or supplied in India provided that such goods are available on equal or better terms than imported goods, and to employ Indian subcontractors having the required skills insofar as their services are available on comparable standards and at competitive prices and terms. Although not intended, this could increase the Corporation's cost of operations.

- Bengal cannot guarantee its ability to obtain the required consents, waivers and extensions from the Director General of Hydrocarbons or Government of India as and when required to maintain compliance with the Corporation's PSCs. Any delays experienced in receiving those consents, waivers and extensions may result in liabilities incurred under the PSCs for failure to maintain compliance with and timely completion of the related work programs, or that the Corporation's partners may not be successful in its efforts to obtain payment from Bengal on account of exploration costs it has expended for which they assert the Corporation is liable or otherwise seek to hold it in breach of that PSC or commence arbitration proceedings against the Corporation.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in British Columbia or that may be enacted in other provinces or countries. The Corporation may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Conflicts of Interest*".

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of security holders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Bengal Energy Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2012, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and,

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and,

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATED as of this 29 day of June, 2012.

(signed) "*Chayan Chakrabarty*"
Chayan Chakrabarty
President and Chief Executive Officer

(signed) "*Bryan C. Goudie*"
Bryan C. Goudie
Chief Financial Officer

(signed) "*Peter Gaffney*"
Peter Gaffney
Chairman of the Reserves Committee

(signed) "*Brian Moss*"
Brian Moss
Director and Reserve Committee Member

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

Report on Reserves Data

To the Board of Directors of Bengal Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's Reserves Data as at March 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2012, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

			Net Present Value of Future Net Revenue (before income tax, 10% discount rate – CAN$)			
Independent Qualified Reserves Evaluator	**Description & Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
DeGolyer and MacNaughton Canada Limited	Appraisal Report as of March 31, 2012 on Certain Properties owned by Bengal Energy Ltd. in Canada and Australia dated May 8, 2012	Canada	-	328	-	328
		Australia	-	16,385	-	16,385
		Total	**-**	**16,713**	**-**	16,713

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated May 8, 2012

DEGOLYER and MACNAUGHTON
CANADA LIMITED

(signed) *"Douglas Christie"*
Douglas S. Christie, P. Geol.
President

SCHEDULE "C"
AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Bengal Energy Ltd. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the Committee are as follows:

1. To assist directors on meeting their responsibilities in respect of the review and approval of the financial statements of the Corporation and related documentation;

2. To provide a communication link between independent directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of the Corporation, none of whom are members of management of the Corporation and all of whom "independent" (as such term is used in National Instrument 52-110 — Audit Committees ("**NI 52-110**") unless the Board shall have determined that the exemption contained in NI 52-110 is available and has determined to rely thereon.

2. The Board shall appoint the Committee Chair, who shall be an independent director.

3. All of the members of the Committee shall be "financially literate" (as defined in NI 52-110) unless the Board shall determine that an exemption under NI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

1. The Committee shall provide oversight on the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. The Committee shall satisfy itself on behalf of the Board with respect to the Corporation's Internal Control Systems and its ability to:

   - identify, monitor and mitigate business risks; and
   - ensure compliance with legal, ethical and regulatory requirements.

3. The primary responsibility of the Committee is to review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtaining explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, MD&A, annual information forms and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information.

5. With respect to the appointment of external auditors by the Board, the Committee shall:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor,
   - including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors.

The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

7. The Committee shall review risk management policies and procedures of the Corporation (e.g. hedging, litigation and insurance).

8. The Committee shall establish a procedure for:

   - the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

9. The Committee shall review and be apprised of any intent of the Corporation regarding the hiring of partners and employees who work on the Corporation's account and former partners and employees of the present and former external auditors of the Corporation.

10. The Committee shall have the authority to investigate any financial activity of the Corporation. All employees of the Corporation are to cooperate as requested by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of the Corporation without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every motion shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.

5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the yearend financial statements) and at such other times as the external auditor and the Committee consider appropriate. At each of these meetings, the Committee will have an "in-camera" session with the external auditors.

6. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Committee Chair.

Definitions — In these Terms of Reference:

"Financially literate" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

Review of Terms of Reference

The Committee shall review and assess these Terms of Reference periodically as it deems appropriate and recommend changes to the Board.

Approved and adopted by the Board: June 10, 2009