**BENGAL ENERGY LTD.**

**ANNUAL INFORMATION FORM**

FOR THE YEAR ENDED

MARCH 31, 2017

June 27, 2017

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## ABBREVIATIONS

| Oil and Natural Gas Liquids | | Natural Gas | |
|---|---|---|---|
| Bbl | barrel | Mcf | thousand cubic feet |
| Bbls | barrels | MMcf | million cubic feet |
| Bopd | Barrels of oil per day | Mcf/d | thousand cubic feet per day |
| Mbbls | thousand barrels | MM | million |
| Bbls/d | barrels per day | MMbtu | million British Thermal Units |
| NGLs | natural gas liquids | Mcfe | thousand feet of gas equivalent |

**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 |
| mD | millidarcy |
| m | metres |
| $m^3$ | cubic metres |
| km | kilometres |
| $km^2$ | square kilometres |
| MBOE | 1,000 barrels of oil equivalent |
| $M | thousands 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 the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**ATP**" means Authority to Prospect.

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

"**Bengal International**" or "**BEII**" means Bengal Energy International Inc., a wholly-owned subsidiary of Bengal 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 maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

"**GLJ**" means GLJ Petroleum Consultants Ltd.

"**GLJ Report**" means the report of GLJ dated June 8, 2017 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at March 31, 2017.

"**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.

"**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*.

"**PEL**" means Petroleum Exploration License.

"**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, 2017.

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 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 presence of a basin centered gas play near the Barrolka permit, the occurrence of natural gas in the Permian Toolachee and Patchawarra sandstone reservoirs, results from drilling of the Nubba-1 exploration well, the timing and occurrence of obtaining final approval from the Ministry of Petroleum and Natural Gas to exit the CY-ONN-2005/1 exploration block in India, the timing of acquiring Barta West 3D seismic, timing of the EPT, 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; and timing of acquisitions. In addition, statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the 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 Australia 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 Australia 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 estimates; the production and growth potential of Bengal's assets; governmental regulation of the oil and gas industry; a failure to obtain required approvals of regulatory authorities, in 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; results of geological, geophysical and reservoir analysis and testing 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; delays resulting from Bengal's inability to obtain required regulatory approvals or other consents, waivers or extensions; imprecision of reserve estimates; 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 Annual Information Form, 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 application for a Potential Commercial Area on ATP 752 Wompi Sub-Block prior to completion and testing of the Nubba-1 Well; the timing of the completion and testing obtaining final approval from the Ministry of Petroleum and Natural Gas to exit the CY-ONN-2005/1 exploration block in India; 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 Annual Information Form 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 Annual Information Form 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 Annual Information Form 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

### Name, Address and Incorporation

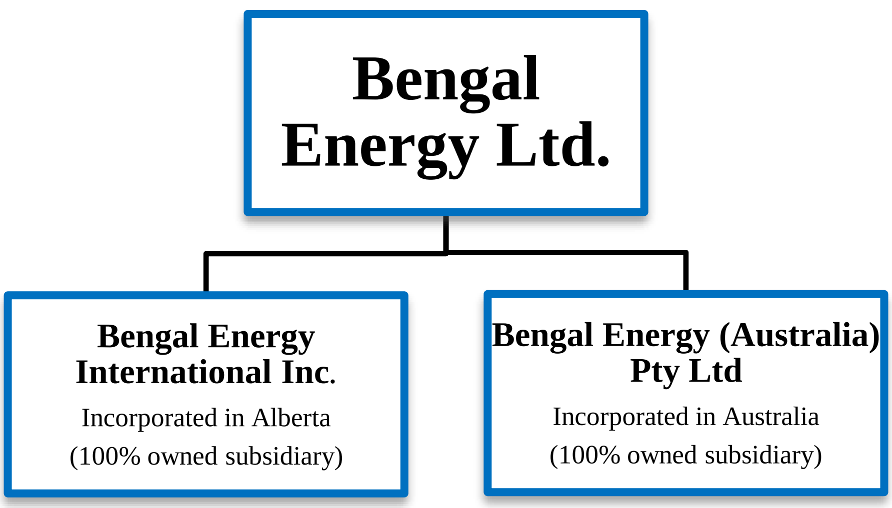
The Corporation was incorporated under the ABCA on May 13, 1996, as "694460 Alberta Inc." On June 18, 1996, the Corporation filed Articles of Amendment to change the Corporation's name to "Briggand Energy Corp.", and on October 8, 1996 to amend its share capital and to remove the private company restrictions 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 2000, 715 – 5th Avenue S.W., Calgary, Alberta T2P 2X6.

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

### Intercorporate Relationships

The following chart illustrates the Corporation's corporate structure as at the date hereof:




## 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 Australia. The Corporation has oil production in the Cooper/Eromanga Basin in Australia and an active inventory of oil and gas opportunities in Australia. The Corporation also has a minor amount of shut in natural gas production in British Columbia, Canada.

### Corporate Strategy

Bengal is an international oil and gas exploration and production company with producing and prospective light oil-weighted assets in Australia. Bengal offers exposure to lower risk, current production and cash flow, combined with longer-term high potential impact exploration projects. The Corporation's strategy is to achieve per share growth in cash flow, production and reserves while establishing an attractive portfolio of future drilling and exploration opportunities. 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. Bengal intends to grow its resource and reserves base within its existing acreage, most of which were acquired through bid rounds in Australia. In addition, Bengal intends to continue building strategic alliances with appropriate local partners and large operators in Bengal's primary areas of focus.

Management of the Corporation will consider asset and corporate acquisition opportunities that meet Bengal's business parameters. Bengal 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 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 obtain 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.

**Prior to the Fiscal Year Ended March 31, 2015**

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

In March 2013, the five-well development and appraisal 2013 drilling campaign commenced on the Corporation's Barta Sub-Block of ATP 752. Each well in the Cuisinier drilling program targeted the primary Murta Formation and total drill depth averaged approximately 1,750 metres per well. All five wells, Cuisinier 7 through to Cuisinier 11 were cased as future oil producers. Cuisinier 12, the sixth and final well of the 2013 Cuisinier drilling program, was spud on August 17, 2013 and was also a successful oil well. The down-hole completion activities for all of the 2013 Cuisinier wells commenced June 2013 and were completed by October 2013.

In April 2013, the Corporation received the final grant of the 15,815 acre Production License on the Cuisinier block ("**PL 303**") from the Queensland Government in Australia. The Department of Natural Resources and Mines granted PL 303 for a term of 21 years commencing on April 8, 2013 and allows production from all current and future wells in the Cuisinier oil pool. PL 303 is 64 $km^2$ in size and located within the boundaries of the Barta Sub-Block of ATP 752.

In June 2013, the Cuisinier to Cook liquids pipeline, located on the Barta Sub-Block of ATP 752 was commissioned and all eight Cuisinier oil wells commenced production. As a result, produced oil is processed through the Cook oilfield production and de-watering infrastructure with approximately 1,600 barrels of oil being delivered to the sales point through the Cook to Merrimelia Oil Pipeline. The balance of the produced oil is trucked from the Cook Trucking Terminal to the Jackson Oil Terminal and then pipelined to sales at the Moomba Gathering Facility.

On December 18, 2013, Bengal closed its acquisition of additional interests in ATP 752 including an incremental 5.357% working interest in the Barta Sub-Block and an incremental 8.08% working interest in the Wompi Sub-Block for a purchase price of AUS $7.5 million / C$7.2 million. Following the acquisition, the Corporation's total working interest in Cuisinier increased to 30.357%.

***ATP 732, Cooper/Eromanga Basin, Onshore Australia***

In May 2013, the Corporation formed a joint venture (the "**JV**") with Beach Energy Ltd. ("**Beach**"), an Australian energy company (ASX: BPT), for the exploration and development of its 100% Tookoonooka Block ATP 732 in the Cooper Basin of Australia. Bengal and Beach commenced activity under their agreement pursuant to which Beach committed to drilling two wells in Tookoonooka and acquire 300 $km^2$ of new 3D seismic, fully carrying Bengal up to a maximum of AUD$11.5 million. At the end of December 2013, the first well, Tangalooma-1, was drilled but it failed to define a commercial hydrocarbon accumulation. Also through December 2013 and January 2014, the additional 3D seismic was acquired. Bengal maintained a 50% interest in ATP 732 and retained operatorship through to the completion of the work program pursuant to the JV. Beach managed the Tangalooma-1 drilling project on behalf of Bengal.

***General***

On April 12, 2013, the term of the non-convertible notes (the "**Non-Convertible Notes**") of the Corporation, which were originally issued in January 2013, was extended to January 24, 2014 and the interest rate was increased from the prime rate plus 3% to 10% per annum.

On April 16, 2013, Bengal closed a brokered private placement of 9,500,666 Common Shares at a purchase price of $0.60 per Common Share for aggregate gross proceeds of approximately C$5,700,400 (the "**April Private Placement**"). The April Private Placement was conducted through a syndicate of agents including Toll Cross Securities Inc. and National Bank Financial Inc. A total of 2,400,300 Common Shares issued pursuant to the April Private Placement were purchased by insiders of the Corporation.

In July 2013, the Corporation closed a non-brokered private placement of 8,000 units ("**Units**") of Bengal at a price of $1,000 per Unit for aggregate gross proceeds of $8.0 million (the "**July Private Placement**"). Each Unit consisted of $1,000 principal amount of 10% unsecured non-convertible redeemable notes ("**Notes**") and either: (i) 156.25

common share purchase warrants ("**Warrants**"), in the case of subscriptions by non-insiders (the "**Non-Insider Units**"), or (ii) 156.25 value appreciation rights ("**VARs**"), in the case of subscriptions by insiders (the "**Insider Units**"). The Notes bear interest at a rate of 10% per annum, payable quarterly, and have a term of 36 months. Following the first anniversary of the closing date of the July Private Placement, the Corporation was required to make quarterly repayments of the outstanding principal of Notes in an amount equal to 6.25% of the principal amount of Notes outstanding on the last day of each applicable quarter. Each whole Warrant entitles the holder thereof, for a period of 36 months following the closing date of the July Private Placement, to acquire one Common Share at a purchase price equal to $0.75 per share. Each whole VAR entitles the holder thereof, for a period of 36 months following the closing date of the July Private Placement, to exercise the VAR and thereby receive a cash payment equal to the difference between the market price of one Common Share on the exercise date and $0.75. Certain insiders of the Corporation purchased 3,500 Insider Units representing over 40% of the total Units issued, and 4,500 Non-Insider Units were purchased by non-insiders The proceeds from the July Private Placement were used to fund the purchase of an additional 5.357% interest in ATP 752. Following the closing of the acquisition, Bengal's working interest increased to 30.357% and net production participation increased to 30.357%.

In November 2013, Mr. Jerrad Blanchard was appointed as Chief Financial Officer of the Corporation effective December 1, 2013.

On January 24, 2014, the term of the Non-Convertible Notes were further extended to January 24, 2015.

**Fiscal Year Ended March 31, 2015**

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

*Barta Sub-Block*

From late March 2014 to early May 2014, Bengal carried out the first of its calendar 2014 two phase development and appraisal drilling campaign in Cuisinier. Bengal drilled four development wells with a 100% success rate and one exploratory dry hole in Phase One of the campaign. The wells targeted the oil-bearing Cretaceous Murta formation, and Bengal's preliminary petrophysical analysis of the well logs showed results comparable with Bengal's six best Cuisinier wells drilled to date. These four development wells were completed and commenced production during August and September of 2014.

On June 13, 2014, Bengal announced completion of drilling operations at the Koki-1 exploration well (the "**Koki-1 Well**") located on the Barta Sub-Block. The well failed to define a commercial hydrocarbon accumulation and was plugged and abandoned. The location was selected using 3D seismic data and was designed to evaluate the extent of the Murta DC70 trend. The Murta DC70 trend is the potential extension of the DC70 sand, which is a sandstone reservoir of Cretaceous age and is the primary and major producing formation in the offsetting Cuisinier oil field. The Koki-1 Well did not encounter the targeted Murta DC70 reservoir and the secondary target indicated minor, uncommercial oil shows.

The Phase Two drilling program at Cuisinier consisted of three appraisal wells, two development wells and one exploration well. The program was conducted between November 2014 and February 2015. Two of the three appraisal wells were cased as future oil producers with the third being declared a dry hole. The two development wells demonstrated a 100% success rate and were also cased and suspended as future oil producers. The Wicho East exploration well (the "**Wicho East Well**") failed to define a commercial hydrocarbon accumulation and was plugged and abandoned.

The JV initiated tie in operations for the two successful Phase Two development wells, Cuisiner-20 and Cuisnier-21 and determined the remaining two appraisal wells would be tied in once commercial flow rates were established after fracture stimulation to be performed late in 2015.

*Wompi Sub-Block*

In early December 2014, Bengal completed drilling operations of the Nubba-1 exploration well (the "**Nubba-1 Well**"). The Nubba-1 Well encountered multiple oil shows within the Jurassic, as well as up to 6m of Permian Toolachee Formation gas pay. The Nubba-1 Well was cased and suspended as a potential Toolachee gas well. Completion and testing of the Nubba-1 Well were subject to a successful completion of a competitor well nearby. Bengal has 38.08% in the Wompi sub- block and the Nubba-1 Well.

***ATP 732, Cooper/Eromanga Basin, Onshore Australia***

As part of the farm-in agreement with Beach, Beach was required to spend AUD$11.5 million on the drilling of two exploratory wells and the acquisition of 300 $km^2$ of new 3D seismic. As of June 2015, one well had been drilled which was plugged and abandoned. The final processing and interpretation of the seismic was completed.

***ATP 934 Barrolka, Queensland, Australia***

On March 1, 2015, the Minister of the Queensland Department of Natural Resources and Mines granted the exploration block located onshore in Australia's Cooper/Eromanga Basin in the State of Queensland Authority to Prospect 934 ("**ATP 934**") to Bengal and the other joint venture members. Bengal had a 50% working interest in ATP 934 and is operator.

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

In August 2014, Bengal completed early relinquishment on the off shore block with the regulator after establishing insufficient merit in the oil and gas potential of this permit to justify further exploration expenditures. Under the terms of the PSC related thereto, in the event Bengal did not complete the minimum work program it was required to pay liquidated damages in lieu of the work program. This payment was made to the Directorate General of Hydrocarbons in September 2014 in the amount of approximately $150,000.

***General***

On July 5, 2014, Mr. Stephen Inbusch, a director of the Corporation, passed away.

On October 24, 2014, Bengal entered into a US $25.0 million secured credit facility (the "**Credit Facility**") with Westpac Institutional Bank. The Credit Facility is secured by Bengal's producing assets in the Cuisinier field in Australia's Cooper Basin and has a three-year term. In advance of the initial draw, Bengal initiated a program to hedge approximately 280,000 barrels of oil over the term of the Credit Facility. Bengal used the initial draw on the Credit Facility to finance Phase Two of the 2014 Cuisinier drilling program, which commenced in November 2014.

Additionally, the Corporation utilized the Credit Facility to fund the redemption price of the $7.5 million principal amount of the Corporation's outstanding Notes. Effective November 24, 2014, Bengal redeemed the Notes at a redemption price equal to $1.03 per $1.00 of outstanding principal amount of the Notes, plus all accrued and unpaid interest thereon to, but excluding, November 24, 2014, for an aggregate redemption price of $7,838,014.

On January 21, 2015, $774,000 aggregate principal amount of Non-Convertible Notes, including all accrued and unpaid interest thereon to, but excluding, the January 21, 2015, were redeemed by Bengal for cash. Certain holders of the remaining $976,000 aggregate principal amount of Non-Convertible Notes agreed to receive the redemption price for a portion of the principal amount of their Non-Convertible Notes through the issuance to such holders of Common Shares at a price of $0.28 per Common Share, in lieu of a cash payment for such aggregate principal amount of Non-Convertible Notes owing to each such holders. The remaining principal amount of such Non-Convertible Notes, as applicable, and accrued and unpaid interest on such Non-Convertible Notes was settled in cash.

**Fiscal Year Ended March 31, 2016**

***ATP 752 Barta Block***

During April 2015, the operator completed remediation work at the Cuisinier-6 well by setting a bridge plug to isolate a potential water source below the Murta formation.

In early May 2015, Bengal and its joint venture partners completed the Phase Two drilling campaign on ATP 752 Barta Block Cuisinier oil field (Bengal's working interest is 30.357%). Average gross production from the Cuisinier field in March 2015, prior to the tie-in of the new Phase Two wells and the reactivation of the Cuisinier-6 well, was approximately 1,653 bopd (502 bopd net to Bengal).

Three of the four cased wells were completed as oil wells. The last well of the Phase Two drilling campaign, Cuisinier-21, tested the northwest flank of the Cuisinier structure. The well encountered oil in the Murta DC70 zone with reservoir pressure at approximately 96% of virgin pressure. The Murta DC70 zone in this well came in structurally below what had been established by other producing wells. Upon perforation the Cuisinier-21 well naturally flowed approximately 380 bopd at 100% oil cut. Bengal expected production rates from the well would increase through installation of mechanical lifting equipment. The well established an oil column of at least 42 metres and further increased the areal extent of the Cuisinier pool. Cuisinier-20, the second of the two development wells in the Phase Two drilling campaign, came in on structure, encountering a well-developed Murta DC70 channel sand that is approximately 14 metres thick.

At the end of 2015, the Cuisinier-1 well had cumulative production of over 192,000 barrels of oil. Cuisinier-20 had been perforated and completed as an oil well. Both Cuisinier-20 and 21 had been flow line connected into Cuisinier facilities. The wells were brought on stream at the end of June 2015 at restricted rates. Production testing of the Cuisinier 21 well in July 2015 indicated a downhole flow restriction that was addressed by an optimization work-over in August 2015. The JV completed tie-in operations for the two successful Phase Two development wells, Cuisiner-20 and Cuisnier-21 during the third quarter ended December 31, 2015.

The remaining Phase Two wells, Cuisinier-17 and Cuisinier-19, were drilled on the northwest and southeast flanks of the Cuisinier structure in December 2014 and January 2015. The Cuisinier-17 well was cased and perforated and was suspended. The Cuisinier-19 well encountered a thick Murta DC70 sand within the established oil window and was also cased and suspended. Given the volatility of crude oil prices, Bengal had evaluated various stimulation options for both Cuisinier -17 and 19 prior to committing additional capital. These two remaining appraisal wells (Cuisinier-17 and Cuisinier-19) were not to be tied in unless commercial flow rates were established post fracture stimulation.

In the third quarter ended December 31, 2015, Bengal and its joint venture parties completed a five well hydraulic stimulation program. Four of the five wells were placed back into production during the fiscal fourth quarter of 2016, demonstrating an aggregate incremental rate of approximately 240 gross bopd or 73 bopd net to Bengal, representing an increase in post stimulation production compared to average production prior to the commencement of the program. The aggregate incremental rate of production for all five wells increased to 73 bopd net to Bengal.

***ATP 934 Barrolka Permit***

Effective April 1, 2015, Bengal acquired an additional 30% working interest in ATP 934 from one of its joint venture partners for a total acquisition price of $0.15 million. The acquisition received Ministerial approval in September 2015.

In May 2015, Bengal made an application for special amendment to the Queensland Government for a smaller work program to reflect geographical conditions that may preclude surface access to parts of ATP 934.

During the first quarter ended June 30, 2015, Bengal reduced its ownership position in this operated and gas prone permit to 71.43% through the disposition of 8.57% to the remaining original joint venture party. In July 2015, Bengal as operator received approval from the Queensland authorities for revised work commitments on this gas focused permit.

In September 2015, Bengal was advised by the regulating authority that revisions to its Environmental Authority granted by the Queensland Department of Environment and Heritage Protection relevant to the new Wild Rivers legislation conditions would be forthcoming during the calendar year 2016.

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

On March 1, 2016, the operator of the permit applied to the Government of Tamil Nadu's Commissioner of Geology and Mining for a further 3 year extension of the PEL to March 1, 2019. The block remained under force majeure, subject to stakeholder negotiations, which was further extended on February 3, 2016.

***ATP 732 Tookoonooka***

Bengal's farm-in partner on ATP 732 announced its withdrawal from the farm-in and reassigned their 50% equity back to Bengal on January 27, 2016. The farm-in partner drilled one well (Tangalooma-1) and completed the acquisition of 300 $km^2$ of 3D seismic. There are no remaining commitments on this permit until after March 2017, at which time a Phase 2 work program will be considered. Bengal now retains a 100% working interest in this permit.

**General**

On April 23, 2015, the directors of Northstar Energy Pty Ltd., a wholly owned subsidiary of the Corporation, resolved to deregister the company and made application with the Australian Securities Investment Commission ("**ASIC**"). The Corporation received formal notification from the ASIC of the company deregistration on June 28, 2015.

On April 10, 2015, Mr. William Wheeler acquired directly and indirectly an additional 57,000 Bengal Shares through the TSX in reliance on the normal course purchase exemption set out in Section 4.1 of National Instrument 62-104.

**Fiscal Year Ended March 31, 2017**

***ATP 752 Barta Block***

During fiscal Q4 2017, the Corporation completed and tied in the Cuisinier-22, Cuisinier-24, Cuisinier-25 and Shefu-1 wells along with the fracture stimulation program at Barta North 1. All five wells drilled during the year were successful in locating oil-bearing sands and four of these wells were completed and commenced production in May 2017. The fifth well, Cuisinier-23 was suspended as a future fracture stimulation candidate following the evaluation of nearby well performance. This drilling program included one appraisal well ("**Cuisinier-22**") and one exploration well ("**Shefu-1**"). Successful drilling of the appraisal and exploration locations have materially increased the Company’s reserve volumes by expanding the applicable pool boundaries.

***ATP 934 Barrolka Permit***

Bengal completed reprocessing and interpretation of 500 line kilometers of 2D seismic over this permit. Seismic amplitude inversion studies were commence during the year and the most favorable areas of the permit have been high-graded for additional detailed geophysical work that may include the acquisition of 3D seismic in 2017. The Corporation was encouraged by recent natural gas discoveries near the Barrolka permit, which suggest the presence of a basin centered gas play in the region, as well as significant conventional potential for natural gas occurrence in the Permian Toolachee and Patchawarra sandstone reservoirs. Bengal is operator with a 71% working interest in this permit.

***ATP 732 Tookoonooka***

The Corporation applied for the regulatory relinquishment of 1/3 of the block and filed a revised work program covering the period March 2015 through March 2019. During the year, Bengal commenced a study of the Permian gas potential along the northern flank of the permit as well as the largely unexplored oil potential in the southern part of the permit closer to the producing Jackson/Jackson South Field.

***ATP 752 Wompi***

The Nubba-1 well drilled on the Wompi sub-block of ATP 752 encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas. Pressure testing, as well as logging, suggested that this Toolachee gas well could be part of a gas column that may be up to 70 metres in height. This suggested the prospective gas pay extends down dip of the Nubba-1 well where seismic indicated the Toolachee section thickens. On July 13, 2016 the operator applied to the Department of Natural Resources and Mines of the Queensland Government for a 22,487 acre Potential Commercial Area ("**PCA**") which will allow for commercialization. This PCA was granted for a period of 15 years on April 3, 2017. Any produced natural gas would likely be pipeline connected to the nearest gas transmission line in the area, which is approximately 5 kilometres from the Nubba-1 well. Wompi (38% Bengal interest) offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential and evaluation by the joint venture of the appropriate timing to continue the development of this discovery continues.

***PRL 84 (formerly PEL 113, Murteree), & Petroleum Production Licence 215, South Australia***

On September 28, 2016, the Corporation assigned its 35% working interest in Petroleum Retention License 84 ("**PRL**") and its 32.67% working interest in Petroleum Production License 215 ("**PPL**") to the operator, Stuart Petroleum Ltd., for a nominal fee which cannot be disclosed for due to confidentiality obligations. No reserves had been assigned to either tenement in the Corporation's independent reserve assessment and evaluation prepared by GLJ Petroleum Consultants Ltd with an effective date of March 31, 2016. ("**2016 GLJ Reserves Report**").

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

Effective June 1, 2016, Bengal and its joint venture partners unanimously agreed and provided notice to the applicable Government of India Authorities of its intention to exit the CY-ONN-2005/1 exploration block. The joint venture was unable to acquire the land rights required for exploration causing a force majeure condition for the duration of the first term of exploration, and is therefore entitled to exit the permit without penalty for unfinished work program commitments. This triggered a $7.4 million impairment equivalent to the asset's entire carrying value in the fourth quarter of the fiscal year ended March 31, 2016. In April of fiscal 2017, this application was accepted by the Director General of Hydrocarbons and is awaiting final approval from the Ministry of Petroleum and Natural Gas. With the exit from the permit, the Corporation has effectively ceased all operations in India.

**General**

On August 25, 2016, Bengal negotiated the extension of the term of its secured credit facility ("**Credit Facility**") with Westpac Institutional Bank to December 31, 2018. The Credit Facility provides a borrowing base of US$15 million, which is to be reduced to US$10 million on December 31, 2017, US$5 million on June 30, 2018 and to nil on December 31, 2018 in the event that it is not further extended.

On December 29, 2016, Bengal completed a fully subscribed rights offering (the "**Rights Offering**") whereby Bengal issued 34,088,898 Common Shares at a subscription price of $0.12 per Common Share for aggregate gross proceeds of $4,090,667.76. Pursuant to the Rights Offering and a standby purchase agreement entered into between Bengal and Texada Capital Management Ltd. (a corporation controlled by Mr. William Wheeler), Mr. Wheeler acquired directly and indirectly an additional 13,201,418 Common Shares. As a result, Mr. Wheeler currently owns, directly or indirectly, or exercises control or direction over 26,891,489 Common Shares, representing approximately 26.3% of the total issued and outstanding Bengal Shares as at the date of this Annual Information Form. The net proceeds from the Rights Offering have been allocated to fund Bengal's development program on the Barta Sub-Block of ATP 752 in Australia's onshore Cooper/Eromanga Basin. This has included the completion and tie in of Cuisinier -22, Cuisinier -24, Cuisinier -25 and Shefu -1 wells, which occurred in Q1 2017, fracture stimulation of Barta North and Cuisinier-22 wells, which occurred in December 2016 and January 2017 and funding the acquisition of Barta West 3D seismic, which is expected to commence following the wet season in calendar during Q3 2017.

**Recent Developments**

***ATP 732 Tookoonooka***

On April 28, 2017 the Corporation lodged a Relinquishment Notice nominating the relinquishment of 290 sub-blocks (33.33% of the original size of the tenement or approximately 218,000 acres) pursuant to the mandatory relinquishment requirement for the permit. If accepted, this relinquishment will reduce the remaining permit area of ATP 732 to 576 sub-blocks (436, 223 acres) effective March 31, 2017. At the same time Bengal lodged an application for the ATP 732 second term Later Work Program ("**LWP**") for the period March 31, 2015 to March 31, 2019. This application was granted May 30, 2017 and was based on additional geological and geophysical studies of previously acquired technical data.

***PCA 155 Nubba/Yilgarn, ATP 752 Wompi Sub Block***

A Potential Commercial Area ("**PCA**") application for the areas surrounding the Nubba-1 well and the previously drilled Yilgarn-1 well was lodged by the operator of this block and PCA 155 Nubba/Yilgarn was subsequently granted by the Queensland Government on April 3, 2017. The PCA has a 15-year term. An Extended Production Test ("**EPT**") of the Nubba-1 well on PCA 155 is planned; however, the operator has not yet communicated the timing for this work.

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

The Government of India Authorities advised at the April 25, 2017 Management Committee Meeting that the operator's request to exit for the CY-ONN-2005/1 without payment of cost for any unfinished work program is now formally under consideration**.**

## 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, 2017 and a preparation date of June 8, 2017.

### Disclosure of Reserves Data

The Corporation engaged GLJ to provide an evaluation of the Corporation's proved, proved plus probable and proved plus probable plus possible reserves as at March 31, 2017. The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. GLJ is an independent reserves evaluator pursuant to National Instrument 51-101 ("**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 GLJ 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 of the Corporation has reviewed and approved the GLJ 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.

All of the Corporation's reserves are located in Australia. In discussion with GLJ during the preparation of the GLJ Report, the reserves previously attributed to Bengal's Oak, British Columbia and Toparoa, Australia properties were written off during the year ended March 31, 2016, and, as such, no reserves have been assigned to those properties in the GLJ Report for the year ended March 31, 2017**.**

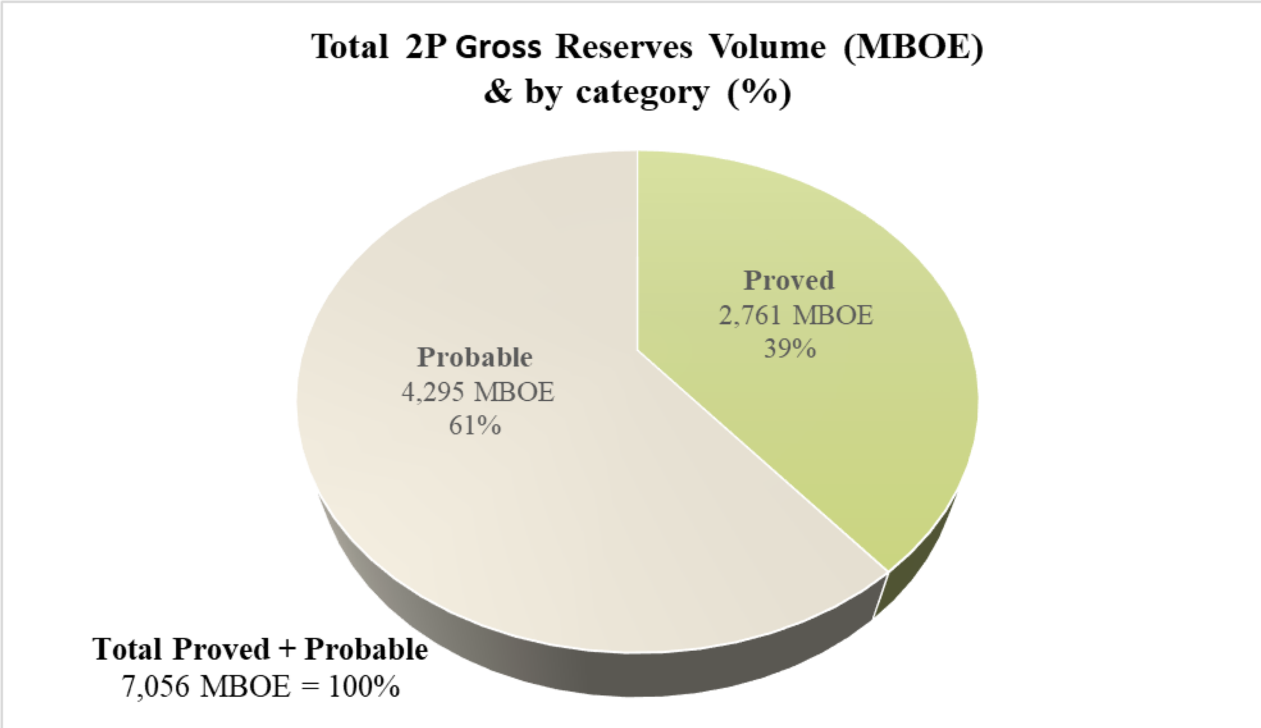
All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables 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.

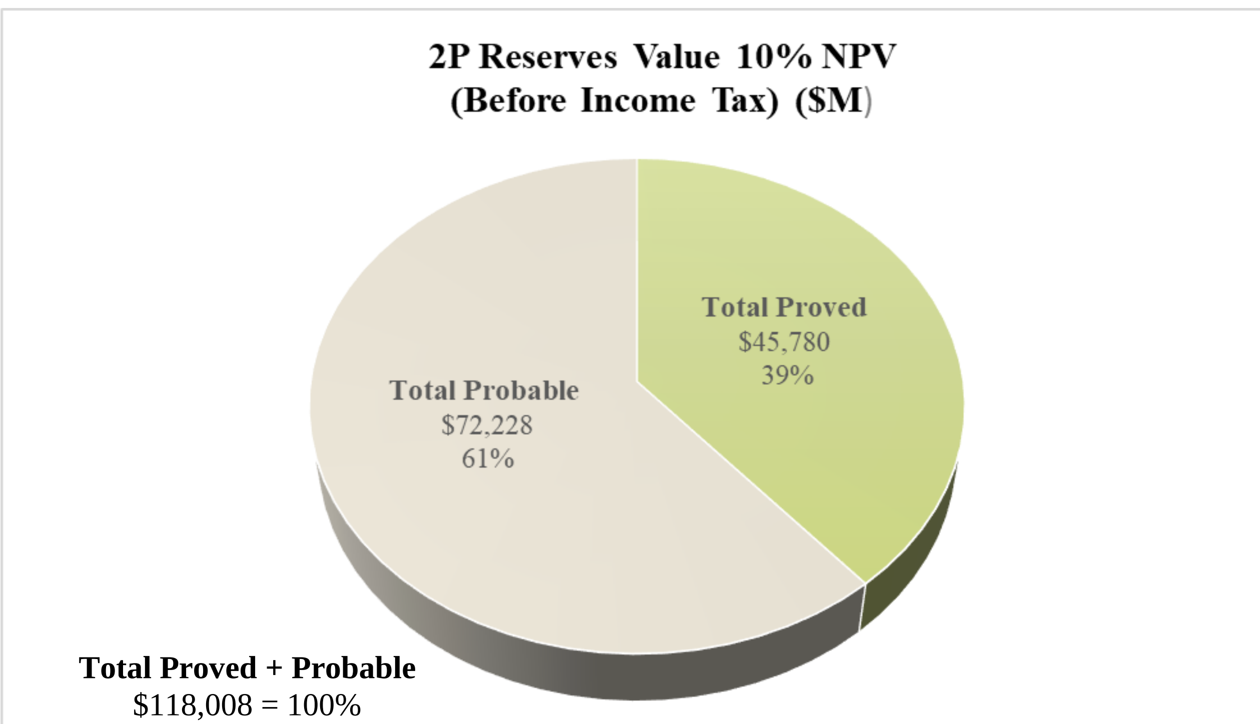
***Reserves Data (Forecast Prices and Costs)***

**SUMMARY OF OIL AND GAS RESERVES**
**AS OF MARCH 31, 2017**
**FORECAST PRICES AND COSTS**

| **CORPORATE TOTAL** | LIGHT CRUDE OIL AND MEDIUM CRUDE OIL | | HEAVY CRUDE OIL | | CONVENTIONAL NATURAL GAS | | NATURAL GAS LIQUIDS | | TOTAL | |
|---|---|---|---|---|---|---|---|---|---|---|
| RESERVES CATEGORY: TOTAL | Gross (Mbbl) | Net (Mbbl) | Gross (Mbbl) | Net (Mbbl) | Gross( MMcf) | Net (MMcf) | Gross (Mbbl) | Net (Mbbl) | Gross (MBOE) | Net (MBOE) |
| Proved Developed | | | | | | | | | | |
| Producing | 406 | 382 | - | - | - | - | - | - | 406 | 382 |
| Non-Producing | 149 | 140 | - | - | - | - | - | - | 149 | 140 |
| Proved undeveloped | 2,207 | 2,069 | - | - | - | - | - | - | 2,207 | 2,069 |
| **TOTAL PROVED** | **2,761** | **2,590** | - | - | - | - | - | - | **2,761** | **2,590** |
| PROBABLE | 4,295 | 4,027 | - | - | - | - | - | - | 4,295 | 4,027 |
| **TOTAL PROVED PLUS PROBABLE** | **7,056** | **6,618** | - | - | - | - | - | - | **7,056** | **6,618** |

Notes:
(1) Estimates of reserves of natural gas include associated and non-associated gas.
(2) "Gross Reserves" are the 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 the 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.
(5) See definitions for reserve categories in the "Notes Regarding the Reserves Data Tables" below.


Total 2P Gross Reserves Volume (MBOE)
& by category (%)
Proved
2,761 MBOE
39%
Probable
4,295 MBOE
61%
Total Proved + Probable
7,056 MBOE = 100%


2P Reserves Value 10% NPV
(Before Income Tax) ($M)
Total Proved
$45,780
39%
Total Probable
$72,228
61%
Total Proved + Probable
$118,008 = 100%

**SUMMARY OF NET PRESENT VALUES**
**OF FUTURE NET REVENUE**
**AS OF MARCH 31, 2017**
**FORECAST PRICES AND COSTS**

| **CORPORATE TOTAL** | BEFORE INCOME TAXES DISCOUNTED AT (%/year) | | | | | AFTER INCOME TAXES DISCOUNTED AT (%/year) | | | | | Unit Value Before Income Taxes Discounted at 10%/year | Unit Value Before Income Taxes Discounted at 10%/year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ($M) | 0% | 5% | 10% | 15% | 20% | 0% | 5% | 10% | 15% | 20% | ($/BOE) | ($Mcfe) |
| PROVED | | | | | | | | | | | | |
| Developed Producing | 10,338 | 9,617 | 8,840 | 8,128 | 7,509 | 10,338 | 9,617 | 8,840 | 8,128 | 7,509 | 23.17 | 3.86 |
| Developed Non-Producing | 5,163 | 4,597 | 4,123 | 3,734 | 3,415 | 5,163 | 4,597 | 4,123 | 3,734 | 3,415 | 29.50 | 4.92 |
| Undeveloped | 61,451 | 44,632 | 32,816 | 24,547 | 18,679 | 46,067 | 34,231 | 25,564 | 19,357 | 14,879 | 15.86 | 2.64 |
| **TOTAL PROVED** | **76,951** | **58,846** | **45,780** | **36,410** | **29,603** | **61,567** | **48,445** | **38,527** | **31,219** | **25,803** | **17.67** | **2.95** |
| Probable | 174,913 | 109,771 | 72,228 | 49,870 | 35,981 | 121,117 | 77,045 | 51,183 | 35,708 | 26,085 | 17.93 | 2.99 |
| **TOTAL PROVED PLUS PROBABLE** | **251,864** | **168,617** | **118,007** | **86,280** | **65,584** | **182,685** | **125,490** | **89,711** | **66,928** | **51,888** | **17.83** | **2.97** |

Notes:
(1) 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.
(2) Income taxes includes all resource income, appropriate income tax calculations and prior tax pools.
(3) The unit values are based on working interest reserve volumes before income tax (BFIT).
(4) The numbers in this table may not add exactly due to rounding
(5) See definitions for reserve categories in the "Notes Regarding the Reserves Data Tables" below.

**TOTAL FUTURE NET REVENUE**
**(UNDISCOUNTED)**
**AS OF MARCH 31, 2017**
**FORECAST PRICES AND COSTS**

| ($M) Reserves Category: | Revenue | Royalties | Operating Costs | Development Costs | Abandonment and Reclamation Costs[3] | Future Net Revenue Before Income Taxes | Income Taxes | Future Net Revenue After Income Taxes |
|---|---|---|---|---|---|---|---|---|
| **TOTAL PROVED RESERVES** | 259,349 | 16,089 | 127,469 | 33,039 | 5,801 | 76,951 | 15,384 | 61,567 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **TOTAL PROVED PLUS PROBABLE RESERVES** | **723,961** | **45,052** | **341,592** | **73,431** | **12,021** | **251,864** | **69,180** | **182,685** |

Notes:
(1) The numbers in this table may not add exactly due to rounding.
(2) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves. See "*Additional Information Relating to Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs*".

**FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF MARCH 31, 2017**

**FORECAST PRICES AND COSTS
(Before income taxes and discounted at 10% per year)**

| Reserve Category | Production Group | ($M) | ($/BOE) | ($/Mcfe) |
|---|---|---|---|---|
| **Proved** | Light Crude Oil and Medium Crude Oil (Including solution gas and associated by-products) | 45,780 | 17.67 | 2.95 |
| | Heavy Crude Oil (Including solution gas and associated by-products) | - | - | - |
| | Conventional Natural Gas (Including associated by-products but excluding solution gas and by-products from oil wells) | - | - | - |
| **Total Proved** | | **45,780** | **17.67** | **2.95** |
| **Proved Plus Probable** | Light Crude Oil and Medium Crude Oil (Including solution gas and associated by-products) | 118,007 | 17.83 | 2.97 |
| | Heavy Crude Oil (Including solution gas and associated by-products) | - | - | - |
| | Conventional Natural Gas (Including associated by-products but excluding solution gas and by-products from oil wells) | - | - | - |
| **Total Proved Plus Probable** | | **118,007** | **17.83** | **2.97** |

Notes:

(1) Unit values are based on the Corporation's net reserves.
(2) The estimated values disclosed do not represent fair market value.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.

Notes Regarding the Reserves Data Tables:

1. Numbers may not add due to rounding.

2. For securities reporting, key economic assumptions will be the prices and costs used in the GLJ Report. The required assumptions may vary by jurisdiction, for example: (a) forecast prices and costs, in Canada under NI 51-101; and (b) constant prices and costs, based on the average of the first day posted prices in each of the 12 months of the reporting issuer's financial year, under US SEC rules (this is optional disclosure under NI 51¬101).

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

   Reserves estimates have been prepared by GLJ in accordance with standards contained in the COGE Handbook. The following reserves definitions are set out by the Canadian Securities Administrators in NI 51-101 (in Part 2 of the Glossary to NI 51-101) with reference to the COGE Handbook.

   **Reserves Categories**

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

   - analysis of drilling, geological, geophysical, and engineering data;
   - the use of established technology; and
   - specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

   *Proved Reserves*

   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.

   *Probable Reserves*

   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.

   *Possible Reserves*

   Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

   Other criteria that must also be met for the classification of reserves are provided in Section 5.5 of the COGE Handbook.

**Development and Production Status**

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories.

*Developed Reserves*

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 nonproducing.

*Developed Producing Reserves*

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.

*Developed Non-producing Reserves*

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.

*Undeveloped Reserves*

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 category (proved, probable and possible) 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.

4. Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves 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 reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible 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 are 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 Section 5 of the COGE Handbook.

5. Forecast Costs and Price Assumptions

GLJ 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, 2017.

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS**
**FORECAST PRICES AND COSTS (AUSTRALIAN PROPERTIES AS OF MARCH 31, 2017)**

| | BRENT ($Cdn/Bbl) | Exchange Rate ($US/$Cdn) | BRENT ($US/Bbl) |
|---|---|---|---|
| YEAR FORECAST | | | |
| 2017 Q2-Q4 | 72.67 | 0.750 | 54.50 |
| 2018 | 75.48 | 0.775 | 58.50 |
| 2019 | 80.62 | 0.800 | 64.50 |
| 2020 | 82.42 | 0.825 | 68.00 |
| 2021 | 83.53 | 0.850 | 71.00 |
| 2022 | 87.05 | 0.850 | 74.00 |
| 2023 | 90.59 | 0.850 | 77.00 |
| 2024 | 94.12 | 0.850 | 80.00 |
| 2025 | 97.64 | 0.850 | 83.00 |
| 2026 | 102.65 | 0.850 | 87.25 |
| 2027+ | +2.0%/yr | 0.850 | +2.0%/yr |

Notes:
(1) 2017 forecast pricing is for last nine months (April 1 - December 31) of 2017.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) Crude oil pricing has been estimated by GLJ as BRENT blend in US dollars. Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.
(5) 2017 forecast pricing is for the last nine months (April 1- December 31) of 2017.
(6) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate. The plant gate price represents the price before raw gathering and processing charges are deducted.
(7) Weighted average historical prices realized by the Corporation for the year ended March 31, 2017 were $70.40/Bbl for light crude oil and medium crude oil.

6. Well abandonment and reclamation costs for wells with reserves or assigned have been included. Additional abandonment costs associated with lease facility abandonment and reclamation expenses have not been included in this analysis. The forecast price and cost assumptions assume the continuance of current laws and regulations. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

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

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

9. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity,

which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

***Reserves Reconciliation***

**RECONCILIATION OF CORPORATION GROSS RESERVES**
**BY PRODUCT TYPE**
**FORECAST PRICES AND COSTS**

| | Light Crude Oil and Medium Crude Oil | | | Heavy Crude 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, 2016 | 2,212 | 3,992 | 6,204 | - | - | - |
| Extensions(1) | 529 | 148 | 677 | - | - | - |
| Improved Recovery(1) | - | - | - | - | - | - |
| Infill drilling(1) | - | - | - | - | - | - |
| Technical Revisions(2) | 159 | 87 | 247 | - | - | - |
| Discoveries | - | 68 | 68 | - | - | - |
| Acquisitions(3) | - | - | - | - | - | - |
| Dispositions(3) | - | - | - | - | - | - |
| Economic Factors(4) | - | (1) | (1) | - | - | - |
| Production | (138) | | (138) | - | - | - |
| **March 31, 2017** | **2,761** | **4,295** | **7,056** | **-** | **-** | **-** |

| | Natural Gas Liquids | | | Conventional Natural Gas | | | Total BOE | | |
|---|---|---|---|---|---|---|---|---|---|
| FACTORS | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved plus Probable (Mbbl) | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved plus Probable (MMcf) | Gross Proved (MBOE) | Gross Probable (MBOE) | Gross Proved Plus Probable (MBOE) |
| March 31, 2016 | - | - | - | - | - | - | 2,212 | 3,992 | 6,204 |
| Extensions[(1)] | - | - | - | - | - | - | 529 | 148 | 677 |
| Improved Recovery[(1)] | - | - | - | - | - | - | - | - | - |
| Infill drilling[(1)] | - | - | - | - | - | - | - | - | - |
| Technical Revisions[(2)] | - | - | - | - | - | - | 159 | 87 | 247 |
| Discoveries | - | - | - | - | - | - | - | 68 | 68 |
| Acquisitions[(3)] | - | - | - | - | - | - | - | - | - |
| Dispositions[(3)] | - | - | - | - | - | - | - | - | - |
| Economic Factors[(4)] | - | - | - | - | - | - | - | (1) | (1) |
| Production | - | - | - | - | - | - | (138) | - | (138) |
| **March 31, 2017** | **-** | **-** | **-** | **-** | **-** | **-** | **2,761** | **4,295** | **7,056** |

Notes:

(1) The above change categories correspond to standard set out in the COGE Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as Extensions and Improved recovery.

(2) Includes technical revisions due to reservoir performance, geological and engineering changes.

(3) 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.

(4) Includes economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions and 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***

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of Bengal's three most recent financial years:

| | Light Crude Oil and Medium Crude Oil (Mbbl) | | Heavy Crude Oil (Mbbl) | | Conventional Natural Gas (MMcf) | | Natural Gas Liquids (Mbbl) | | Total Oil Equivalent (MBOE) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed(1) | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End |
| 2015 | 403 | 1,595 | - | - | - | - | - | - | 403 | 1,595 |
| 2016 | 206 | 1,817 | - | - | - | - | - | - | 206 | 1,817 |
| **2017(1)** | **406** | **2,207** | - | - | - | - | - | - | **406** | **2,207** |

Note:
(1) Refers to reserves first attributed in this fiscal year ending on the effective date March 31, 2017.

Proved undeveloped reserves are associated with both undrilled locations and drilled wells that have not yet been logged, or tested as of the effective date of the reserve evaluation. Proved undeveloped reserves partially relate to planned infill drilling locations. The majority of the proved undeveloped locations are scheduled to be on production within a five year time frame.

As of March 31, 2017, Bengal's proved undeveloped reserves represented 79.9% of Bengal's total proved reserves, with proved plus probable ("**P+P**") undeveloped reserves representing 87.7% of its P+P reserves. In light of the timing of Bengal's drilling program relative to its year end reserves evaluation, a portion of these undeveloped reserves will be converted to proved developed through calendar 2017. In addition, given that the focus of Bengal's drilling program was on appraisal and pool delineation rather than development, the reserve evaluation inherently includes greater development potential which is reflected within the report. Further, through an ongoing planned drilling program in Australia over the next 5 years, it is anticipated that a majority of the proved undeveloped reserves will be converted to proved developed, and the majority of probable undeveloped to probable.

***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:

| | Light Crude Oil and Medium Crude Oil (Mbbl) | | Heavy Crude Oil (Mbbl) | | Conventional Natural Gas (MMcf) | | Natural Gas Liquids (Mbbl) | | Total Oil Equivalent (MBOE) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed(1) | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End |
| 2015 | 1,561 | 3,244 | - | - | - | - | - | - | 1,561 | 3,244 |
| 2016 | 649 | 3,874 | - | - | - | - | - | - | 649 | 3,874 |
| **2017(1)** | **201** | **3,979** | **-** | **-** | **-** | **-** | **-** | **-** | **201** | **3,979** |

Note:
(1) Refers to reserves first attributed in this fiscal year ending on the effective date March 31, 2017.

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 five 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 and demand, 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. A 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 GLJ Report indicates that Bengal has 3,979 thousand barrels of light crude oil and medium crude oil, no conventional natural gas and no natural gas liquids reserves defined as "probable undeveloped". The change in "probable undeveloped" light crude oil and medium crude oil reserves year over year results from extensions, discoveries, and technical revisions associated with the Murta formation within the Cuisinier property, economic factors and proved production. There are no probable undeveloped conventional natural gas and NGLs reserves as a result of economic factors and no future production.

***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 the fiscal year ended March 31, 2017 as well as the "*Risk Factors*" and "*Principal Properties*" sections herein.

The Corporation does not anticipate any unusually high abandonment or reclamation costs. Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Bengal's audited financial statements for the year ended March 31, 2017 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

***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:

| **CORPORATE TOTAL** | Forecast | |
|---|---|---|
| $M | Prices and Costs | |
| Year | Proved | Proved Plus Probable |
| 2017 | 387 | 918 |
| 2018 | 5,239 | 6,297 |
| 2019 | 7,634 | 7,634 |
| 2020 | 7,786 | 8,565 |
| 2021 | 7,942 | 8,736 |
| 2022 | 4,050 | 8,101 |
| 2023 | - | 8,263 |
| 2024 | - | 8,428 |
| 2025 | - | 8,597 |
| 2026 | - | 7,892 |
| 2027 | - | - |
| Thereafter | - | - |
| **Total Undiscounted** | 33,039 | 73,431 |
| **Total Discounted @ 10%** | 24,649 | 45,619 |

Notes:
(1) Future development costs shown are associated with booked reserves in the GLJ 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 $33.0 million will be sufficient to fund the future development costs of its proved reserves disclosed above and $73.4 million 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.

On December 29, 2016, Bengal completed a Rights Offering, raising aggregate gross proceeds of $4,090,667.76. The net proceeds from the Rights Offering have been allocated to fund Bengal's development program on the Barta Sub-Block of ATP 752 in Australia's onshore Cooper/Eromanga Basin. This program includes the completion and tie in of Cuisinier 22, Cuisinier 24, Cuisinier 25 and Shefu 1, which operations were completed in calendar Q1 2017, fracture stimulation of Barta North and Cuisinier 22 wells, in December 2016 and January 2017 and funding the acquisition of Barta West 3D seismic, which is expected to commence following the wet season, in calendar Q3 2017

## 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 Australia.

The following is a description of the Corporation's principal oil and natural gas properties as at March 31, 2017, 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, 2017 based on operator statements. The reserve amounts stated are gross reserves, as at March 31, 2017 based on forecast costs and prices as evaluated in the GLJ 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.

Cooper/Eromanga Basin, Onshore, Australia

Bengal has a large acreage position across the onshore Cooper/Eromanga Basin of Australia of approximately 1.1 million gross acres. Bengal's Cooper/Eromanga acreage is split among four separate blocks of land that are covered by: ATP 752, ATP 732, ATP 934 and PRL 182 (formerly PEL 103A).

(a) ATP 752, Queensland, Australia

Bengal has multiple interests in ATP 752. ATP 752 is located on the Cooper/Eromanga Basin and is subdivided into the Barta Sub-Block (Bengal 30.357% working interest) and the Wompi Sub-Block (Bengal 38.08% working interest).

*Barta Sub-Block*

The end of the first four-year permit term of ATP 752 was July 31, 2010. The ATP 752 permit was renewed for another four-year term on July 1, 2010 and was again renewed 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 ATP 752; the bulk of the relinquished area was assessed as poorly prospective or at least having very high exploration risk. In May 2014, the Government of Queensland issued the "Land and Other Legislation Amendment Bill 2014" which provided for an automatic extension of the relinquishment date for ATP 752 of two additional years. This extended the second term relinquishment date to July 31, 2016 at which time a further 33.33% of the block was relinquished. This further relinquishment does not affect any existing leads or prospects identified by either Bengal or its partners. The final 33.33% relinquishment will take place on July 31, 2018 excluding any Petroleum Leases or Potential Commercial Areas.

The Barta Sub-Block now comprises 154,638 gross acres (46,933 net acres) as well as the 15,815 gross acre (4,800 net acre) PL 303. The Cook oil field sits immediately east of the Barta Sub-Block and an oil discovery (James-1) offsets the sub-block's west boundary. Two wells drilled on the southwestern parcel had oil shows. Existing and new seismic data has identified numerous, large, prospective structures on the sub-block.

Prior to 2013, 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 it was wet in the principal target zone, oil was discovered 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. Bengal further increased its interest to 30.357% of the Barta Sub-Block and the Cuisinier field through a purchase of an additional 5.357% interest in 2013.

In May 2010, production commenced from the Corporation's Cuisinier 1 oil discovery. The Cuisinier-1 Well was the first well drilled on the Cuisinier structure. The Cuisinier structure has been interpreted from 3D seismic data to be one of several 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 km 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.

Cuisinier 2 and 3 were drilled in 2010 and 2011, respectively to follow up on the Cuisinier 1 discovery. In 2012, Cuisinier 4, 5 and 6 plus the Cuisinier North 1 Wells were drilled, cased, completed and equipped bringing the total to eight oil wells. In 2012 all wells were flow lined to the central Cuisinier-1 facility (see "*Exploration and Development Activities*" below for detailed well descriptions).

The previously equipped Barta North 1 Well was tied into the existing Cuisinier 1 facility via 4.5 km of pipeline and the well was commissioned in Q4 2012. In addition to the infrastructure work for Barta North 1, strategies to improve the operability and on-stream times of the existing production at Cuisinier have been implemented, including the connection of the facility at Cuisinier-1 to nearby existing infrastructure at Cook and the potential expansion of the existing Cook facility to include water handling infrastructure. The pipeline to Cook was completed in December 2012 and, following further engineering and mechanical work, became fully operational in Q2 2013. In April 2013, Bengal received the final grant of PL 303 from the Queensland Government in Australia, allowing all eight Cuisinier oil wells to produce. In June 2013, the Cuisinier to Cook pipeline was commissioned enabling the production from all eight wells to be delivered to sales points through a pipeline, rather than trucking.

In December 2012, the operator completed the acquisition of an additional 220 km$^2$ of 3D seismic extending the existing 3D seismic coverage northward from Cuisinier North 1 in order to pursue newly generated exploration leads and prospects. Based on this new 3D seismic, a number of exploration targets were identified. The Koki-1 Well was the first of two exploration wells drilled in 2014. The location was selected using 3D seismic data and was designed to evaluate the extent of the Murta DC70 trend approximately four kilometers to the north of the Cuisinier Field which had completed a successful 2014 Phase One development program. The Koki-1 Well was drilled to a vertical depth of 2,573 meters and also tested a deeper secondary Birkhead-Hutton zone. The Koki-1 Well did not encounter the targeted Murta DC70 reservoir and the secondary target indicated minor, uncommercial oil shows. The Koki-1 well was a step-out beyond Bengal's currently evaluated Cuisinier field reserves area and did not have an impact on the Corporation's 2014 booked reserves.

The Wicho East-1 Well, the second of two exploration wells drilled in the Barta Sub-Block in 2014, had a primary target in the deeper Jurassic Hutton horizon, approximately 10 kilometres north of the producing Cook Hutton oil field. The well was selected to test a structural closure, which was only partly tested by the old flank Wicho-1 well. The well did come in substantially high to the old Wicho-1 well; however, it failed to intersect a commercial hydrocarbon accumulation and was plugged and abandoned.

The 2015 fracture stimulation campaign included the Cuisinier-3, Cuisinier-5, Cuisinier-9, Cuisinier-12 and Cuisinier-14 wells. Post fracture production rates increased in aggregate by approximately 240 barrels of oil per day, (net 73 bopd). In late 2016, the newly drilled but not yet tied in Cusinier-22 was fracture stimulated and in January of 2017 the same procedure was conducted on the Barta North 1 well where gross production in the ensuing 30 day period increased from pre frac rates of 18 bopd up to 43 bopd. Cuisinier-22 rates are yet to be determined but are expected during calendar Q3 of 2017.

The 2016 drilling campaign commenced in July 2016 and consisted of five wells: Cuisinier-22, followed by Cuisinier-23, Cuisinier-25, the Shefu-1 exploration well and finally Cuisinier-24. All five wells have been cased as potential Murta oil wells. With the exception of Cuisinier-23, which encountered poor quality Murta reservoir sand, the other four wells all met or exceeded pre-drill expectations in terms of both structure and Murta reservoir sand development. Completion of four of these five wells Cuisinier-24, Cuisinier-22, Shefu-1 and Cuisinier-25 commenced in December 2016. All wells were perforated and pumps run. Cuisinier-22 was fracture stimulated and swabbed. At the fiscal year ended March 31, 2017 none of these wells had been evaluated. In May 2017 the four completed wells were tied in. For additional details, see "*Oil and Gas Wells – Exploration and Development Activities*".

*Wompi Sub-Block*

The Wompi Sub-Block now comprises a total of 117,128 acres after relinquishing 98,595 acres on July 31, 2016. Pursuant to the original farm-in agreement, the operator completed the acquisition of over 200 km$^2$ of new 3D seismic over the Wompi Sub-Block of ATP 752. The 3D data (the Bowen and Genoa 3D surveys) was processed, merged with previous 3D datasets and interpreted by the operator. The operator identified two principal 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; however the well was unsuccessful and subsequently abandoned.

In 2012, Bengal increased its working interest in the Wompi Sub-Block from 19.5% to 38.08% by drilling the Cuisinier North 1 well on the Barta Sub-Block as the Wompi option well and paying 60% of all drilling costs on the Cuisinier North 1 well.

The Corporation evaluated the entire Wompi Sub-Block and high graded several prospects on existing 3D and drilled one well in the fourth quarter of calendar 2014. This well (the "**Nubba-1 Well**") is directly offsetting the existing Bowen Field on an untested structure which trends south from Bowen. The Nubba-1 Well location was selected using 3D seismic data and was designed to evaluate the oil bearing sands currently producing from the offsetting Bowen field located 2.1 kilometres to the northeast. The Nubba-1 Well encountered light oil shows in five different Jurassic reservoir bearing formations, but these shows appear to be residual oil. The well intersected up to 6.2 meters of gas pay in the Permian Toolachee Formation with reservoir pressure data indicating a potential gas column of up to 70 meters. Based on these findings, the operator cased and suspended the well as a potential Toolachee gas well.

In addition to the Nubba-1 Well, a number of potential leads have been identified on existing 2D and 3D seismic. On July 13, 2016 the operator applied to the Department of Natural Resources and Mines of the Queensland Government for a 22,487 acre Potential Commercial Area ("PCA") for the areas surrounding the Nubba-1 well and the previously drilled Yilgarn-1 well**.** PCA 155 Nubba/Yilgarn **("PCA 155")** was granted on April 3, 2017 for a 15-year period. For additional details, see *"General Development of the Business - Fiscal Year Ended March 31, 2015, 2017 - ATP 752 Wompi* "*Principal Properties" and "Exploration and Development Activities".*

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.

(b) ATP 732 Tookoonooka, Queensland, Australia

Bengal completed the purchase of a 100% interest in ATP 732 and became the operator thereof following the formal grant of the permit by the Queensland Government in March 2011. Native title and cultural heritage agreements were arranged with the Boonthamurra aboriginal peoples enabling exploration activities on ATP 732 to commence. The initial four-year term of the permit required 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. In May of 2014, the Government of Queensland issued the "Land and Other Legislation Amendment Bill 2014" which provided for an automatic extension of the relinquishment date for ATP 732 of two additional years. In July 2014, the Corporation received formal correspondence from the Department of Natural Resources and Mines of the Queensland Government advising of a statutory extension of the ATP 732 work program and relinquishment condition from March 31, 2015 to March 31, 2017.

Effective March 31, 2017 and pursuant to the expiry of the initial four-year term and the two year statutory extension, Bengal relinquished 33.33% of ATP 732; the bulk of the relinquished area having been assessed as poorly prospective or having very high exploration risk. The requisite regulatory relinquishment application and Later Work Program application were filed and the LWP was granted May 30, 2017. The relinquishment does not affect any existing leads or prospects identified by Bengal. The current, (second) four year term of the permit continues the remaining tenement area of 436,223 acres to March 31, 2019 at which time another 33.33% of the original permit will be relinquished.

Permit ATP 732 is large in size (436,245 acres) and has been tested by only eight exploration 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. A partial list of the prospective reservoirs at Tookoonooka is outlined in the following paragraphs.

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 were 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 and 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%, permeability up to 2,500 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 732. 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 of new 2D seismic and 50 $km^2$ of new 3D seismic, an amount greatly in excess of the actual required work commitments. This seismic was processed and interpreted to allow for drilling in the third and fourth quarters of 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 were 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.

In 2012, Bengal commenced drilling on the Tookoonooka permit with the Caracal-1 exploration well ("**Caracal-1 Well**"). The Caracal-1 Well encountered good oil shows in the Wyandra sandstone and the formation was subsequently cored. When the core was recovered oil was observed bleeding from the core into the core barrel. Preliminary petrophysical analysis determined there was approximately 9.5 metres of potential pay in the Wyandra. Upon completion the zone swabbed and recovered 5 barrels of 53 degree API oil (see "*Exploration and Development Activities*" below for detailed well descriptions).

The Caracal-1 Well was drilled into the Murta formation and then cased before reaching the originally prognosed total depth. This was done to mitigate any potential formation damage in the Wyandra due to some of the clays known to exist at the level. The deeper Birkhead, Hutton and Basement targets remain and plan to be evaluated during future appraisal drilling at Caracal.

In May 2013, Bengal announced the formation of a joint venture with established Cooper Basin explorer, Beach. Beach committed to fully fund the drilling of two exploration wells, as described below, and the acquisition of 300 km2 of new 3D seismic, which was completed in February 2014, in Tookoonooka up to a total maximum value of AUD$11.5 million.

The first well, Tangalooma-1, was drilled in December 2013, approximately two kilometers north-northeast of the Caracal-1 Well with the Jurassic Hutton being the primary target and the Cretaceous Wyandra as a secondary target. The well had oil shows but failed to find commercial hydrocarbons and was plugged and abandoned.

Concurrent with the drilling of the Tangalooma-1 well, a 300 $km^2$ 3D seismic program commenced with data acquisition completed in February 2014. Processing and preliminary interpretation of this data was completed in the fourth quarter of 2015. The second four-year term of the agreement running from March 2015 to March 2019 called for a modest LWP consisting of geological and geophysical investigations using previously acquired data. There are no remaining commitments on this permit until after March 2017. Bengal’s preliminary review of the 3D seismic results and evaluation of options towards further exploration on this permit has highlighted the need to focus on the deeper Permian gas targets in the northern part of the permit and/or the Jurassic/Cretaceous oil potential in the far southwest part of the permit. These two areas are viewed to have less charge/migration and seal risk than the areas initially targeted by both Bengal and Beach with the drilling of Caracal-1, and the Tangalooma-1 wells.

Marketing options for any future commercial oil and gas production from the ATP 732 permit have been investigated through an independent specialist consultant.

Bengal is the operator and in early 2016, increased its working interest in ATP 732 from 50% to 100%. 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. For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2016*" and "*General Development of the Business – Fiscal Year Ended March 31, 2017*".

(c) ATP 934 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 currently holds a 71.43% working interest in the ATP 934 block and is the operator. ATP 934 sits in the heart of the Cooper/Eromanga Basin and is surrounded by known gas fields. ATP 934 flanks the east margin of the large Barrolka gas field. Recent activity west of ATP 934 has resulted in some new oil discoveries. Bengal believes that ATP 934 is prospective for deep basin-centered and tight gas prospects. To date, five undrilled structural leads have been identified as conventional gas drilling opportunities.

In March 2011, Bengal successfully completed negotiations and entered into an agreement with the Wongkumara people regarding native title on ATP 934. The Corporation completed the environmental assessment and submitted the final documents late in 2012.

On March 1, 2015, Bengal received notice of the formal grant of ATP 934 for a period of 12 years comprised of three four-year terms. In the first four-year work program, Bengal is committed to capital spending of approximately $23 million (net $16 million) dedicated to acquisition of new 3D seismic as well as drilling of up to three new wells.

In the current work program, Bengal completed its year one commitment of reprocessing 500 km of 2D seismic. Year two of the work program will see the acquisition of 200 $km^2$ of 3D seismic, followed in year three by the drilling of either one or two wells and the acquisition of 250 $km^2$ of 3D. The drilling of another well in year four of the work program will complete the Corporation's first phase work commitments.

ATP 934's first four year work program runs from March 1, 2015 through February 28, 2019. The permit can be renewed twice for additional four year terms for a total tenure period of twelve years subject to the negotiation of additional work programs for each four year term. The Queensland Wild Rivers legislation, which was recently replaced by the Queensland Regional Planning Interest Framework, was evaluated and found to have no substantial effect on the Bengal's planned work program.

In April 2015, the Corporation completed a transaction to acquire an additional 21% interest in the Barrolka permit. The Corporation expects to commence exploration activities once the joint operating agreement has been finalized with its partners. See "*General Development of the Business – Fiscal Year Ended March 31, 2016*" for further details.

In calendar 2016, Bengal completed the geological and geophysical interpretation of the permit with a total of five prospect areas identified. These prospects are all gas focused and targeting the Permian Toolachee and Patchawarra formations. All work to date has been completed with the existing 2D seismic covering the permit. In December 2016, Bengal initiated a quantitative interpretation of a subset of 2D seismic lines. A total of 410 line kilometers of 2D seismic data has been incorporated into this analysis, the aim of which is to better characterize the reservoir and distinguish sand rich regions from coal prone areas. This work has recently been completed which, will further reduce the risk profile of the property and further exploration activities on the permit. Bengal is the operator of ATP 934. 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% and 1.75%, subject to certain conditions, will be reserved to the native title owners.

(d) Other Properties

The Corporation held interests in a number of wells and lands in other portions of Australia at March 31, 2017, which are not considered to be part of the Corporation's principal oil and natural gas properties. Additionally, as previously noted, in discussions with GLJ during the preparation of the GLJ Report, the reserves previously attributed to Bengal's Oak, British Columbia and Toparoa, Australia properties were written off during the year ended March 31, 2016 and, as such, no reserves have been assigned in the GLJ Report to those properties for the year ended March 31, 2017. The following is a general description of the each of the Corporation's other properties.

(i) PRL 84 (formerly PEL 113, Murteree) and PPL 215, South Australia

On September 28, 2016, the Corporation assigned its 35% working interest in PRL 84 and its 32.67% working interest in PPL 215 to the operator.

For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2017*".

(ii) PRL 182 and GSEL 660 (formerly PEL 103, Aspen), South Australia

In May 2015, the Corporation's partner and Operator in PEL 103 applied to the regulatory authority of the South Australian Government for the conversion of this permit to a PRL and a Gas Storage Exploration License ("**GSEL**"). This application was granted on November 20, 2015 with a new five year extension to extend the relinquishment timeline to November 19, 2020. The Corporation holds a 25% working interest in this license and is subject to its proportionate share of "eligible activity" expenditures of $12.33 per square kilometre per day. The Corporation’s working interest in these tenements comprise a net area of fourteen (14) square kilometres and its carrying cost/eligible activity exposure is $63,006 per annum.

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

(iii) AC/RL 10 (formerly AC/P 24), Ashmore Cartier Area, Timor Sea, Offshore Australia

Bengal holds a 10% working interest in the Ashmore Cartier Retention License 10 ("**AC/RL 10**"), located in the Ashmore Cartier area offshore Australia, comprised of approximately 168 square kilometers (41,514 acres). Bengal is partnered with PTTEP Australia Timor Sea Pty Ltd (90% working interest and operator). Bengal's interest was earned by the drilling of a discovery oil well at Katandra-1 in December 2004. Though successfully demonstrating that recoverable light oil exists on the Katandra structure, the gross oil column penetrated by the Katandra-1 well is not economically viable at the present time and would require further successful appraisal drilling for commercial development.

This permit was granted as a five year Petroleum Retention Lease, AC/RL 10 on March 22, 2013 expiring March 21, 2018. Subject to fulfilling acceptable later work programs, AC/RL 10 may be continued for two further five year terms. The operator continues to reprocess existing 3D seismic data and evaluate commercialization options.

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

On June 1, 2016, Bengal and its joint venture partners provided notice to the applicable Government of India Authorities of its intention to exit the CY-ONN-2005/1 exploration block. Negotiations with the regulator on completing this exit are ongoing. See "*General Development of the Business – Fiscal Year Ended March 31, 2017* for additional details.

(v) 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 a 41.9% working interest in Section 30 86-17W6M from petroleum and natural gas 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. No reserves were assigned to the Oak property in the March 31, 2016 GLJ Evaluation Report.

As per the Dominion Land Survey, each full section is comprised of 640 acres. Additionally, Bengal has a 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 to be considered when gas prices become economically viable. The Corporation currently has three non-producing gas wells, all of which are located on the Oak property.

**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, 2017. As at March 31, 2017, the Corporation had an interest in 32 gross (10.1 net) oil and natural gas wells as follows, all such wells are onshore wells.

| | Producing Wells | | | | Non-Producing Wells | | | | Total | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil Wells | | Gas Wells | | Oil Wells | | Gas Wells | | Oil Wells | | Gas Wells | | **TOTAL** | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | **Gross** | **Net** |
| **Total** | **24** | **6.68** | **0** | **0.00** | **4** | **1.91** | **4** | **1.52** | **28** | **8.59** | **4** | **1.52** | **32** | **10.10** |
| Australia | 24 | 6.68 | 0 | 0.00 | 4 | 1.91 | 1 | 0.38 | 28 | 8.59 | 1 | 0.38 | 29 | 8.97 |
| Canada | 0 | 0.00 | 0 | 0.00 | 0 | 0.00 | 3 | 1.14 | 0 | 0.00 | 3 | 1.14 | 3 | 1.14 |

Note:

(1) This table does not include dry wells, abandoned wells or wells which have never produced.

No wells have been drilled in India prior to the year ended March 31, 2017. Additionally, in discussion with GLJ during the preparation of the GLJ Report, the reserves previously attributed to Bengal's Oak, British Columbia and Toparoa, Australia properties were written off during the year ended March 31, 2016 and, as such, no reserves have been assigned in the GLJ Report to those properties for the year ended March 31, 2016.

**Properties with No Attributable Reserves**

The following table sets out the Corporation's developed and undeveloped land holdings as at March 31, 2017

| | Developed Acres | | Undeveloped Acres | | Total Acres | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| **Total** | **17,735** | **5,429** | **1,601,688** | **1,091,081** | **1,619,422** | **1,096,510** |
| Australia | 15,815 | 4,801 | 1,367,926 | 1,020,952 | 1,383,740 | 1,025,753 |
| Canada | 1,920 | 628 | - | - | 1,920 | 628 |
| India(2) | - | - | 233,762 | 70,129 | 233,762 | 70,129 |

Notes:

(1) Bengal calculates both its gross and net acres on a per lease basis.
(2) As at March 31, 2017 the Corporation had no reserves attributed to its Indian or Canadian properties.

For a summary of the Corporation's work commitments in Australia, see the descriptions under the headings "*Other Oil and Gas Information – Principal Properties*" above, as well as "*General Development of The Business – Fiscal*

*Year Ended March 31, 2016* ", *Fiscal Year Ended March 31, 2017*, above and "*Exploration and Development Activities – Australia* ", below.

The Corporation expects that, under mandatory relinquishment terms of the State of Queensland, the rights to explore on approximately a further 252,800 (net 86,000) acres, representing the balance of ATP 752**,** excluding PPL 303 will be relinquished on July 31, 2018. The Corporation has made application for a new Petroleum Production License, PPL 1028, to allow for production of the Cuisinier-19 well and has applied for a Potential Commercial Area, PCA 155, for 15 years covering the Nubba project on the Wompi block. These areas, if the applications are granted will continue beyond July 31, 2018. Additionally, for ATP 732, the Corporation has made application to relinquish 290 sub blocks equal to approximately 218,000 (net 218,000) acres on March 31, 2017. Subject to regulatory approval, a total of 304,000 net acres of Bengal's current oil and gas acreage will expire on or before March 31, 2017 by virtue of mandatory relinquishment terms of some of the permits it holds in Australia's Cooper Basin. No further relinquishments are expected for the year ending March 31, 2018.

Additionally, on June 1, 2016, Bengal and its joint venture partners provided notice to the applicable Government of India Authorities of its intention to exit the CY-ONN-2005/1 exploration block. See "*General Development of the Business – Recent Developments – Cauvery Basin, Onshore India (CY-ONN-2005/1)*".

### *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.

Bengal has entered into financial commodity contracts as part of its risk management program to manage commodity price fluctuations related to its primary producing assets being the Cuisinier field in Australia's Cooper Basin.

The Corporation has managed the price application to production volumes through the following contracts:

| Time Period | Type of Contract | Quantity Contracted (bbls) | Price Floor (US$/bbl) | Price Ceiling (US$/bbl) |
|---|---|---|---|---|
| April 1, 2017 – May 31, 2017 | Oil – Swap | 15,814 | 80.00 | 80.00 |
| April 1, 2017 – May 31, 2017 | Oil – Put option | 12,937 | 80.00 | - |
| July 1, 2017 – December 31, 2018 | Oil – Swap | 67,373 | 47.00 | 47.00 |
| July 1, 2017 – December 31, 2018 | Oil – Put option | 67,373 | 47.00 | |

The fair value of the financial contracts outstanding as at March 31, 2017 is an estimated**]** asset of $0.7 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

### *Tax Horizon*

The Corporation does not expect to pay current income tax for the 2018 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2019 or beyond.

***Capital Expenditures***

The following table summarizes capital expenditures related to the Corporation's activities for the year ended March 31, 2017:

| CAPITAL EXPENDITURES | Canada (M$) | Australia (M$) | India (M$) | Total (M$) |
|---|---|---|---|---|
| **Property Acquisition costs – Proven** | - | - | - | - |
| **Property Acquisition costs – Unproven** | - | - | - | - |
| **Exploration:** | | | | |
| Geological and Geophysical | 38 | 369 | - | 407 |
| Drilling | - | - | - | - |
| Completions/facilities | - | - | - | - |
| Acquisitions | - | - | - | - |
| Exploration Subtotal | 38 | 369 | - | 407 |
| **Development:** | | | | |
| Geological and Geophysical | - | 477 | - | 477 |
| Drilling | - | 2,974 | - | 2,974 |
| Completions | - | 1,760 | - | 1,760 |
| Acquisitions | - | - | - | - |
| Development Subtotal | - | 5,211 | - | 5,211 |
| **TOTAL EXPENDITURES** | **-** | **5,580** | **-** | **5,618** |

Note:
(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, 2017:

| | **Exploratory Wells** | | **Development Wells** | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| **TOTAL** | **1** | **0.3036** | **4** | **1.214** |
| Light Crude Oil and Medium Crude Oil | 1 | 0.3036 | 4 | 1.214 |
| Heavy Crude Oil | – | – | – | – |
| Conventional Natural Gas | – | – | – | – |
| Dry | – | – | – | – |
| Service/Other | – | – | – | – |
| Stratigraphic Test | – | – | – | – |

During the year ended March 31, 2017, Bengal completed a five well drilling program at Cuisinier. See "*General Development of the Business – Fiscal Year Ended March 31, 2017*", "*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*" and below for details regarding the drilling program. No drilling was undertaken in Canada or India during the year ended March 31, 2017.

***Australia***

See "*General Development of the Business – Fiscal Year Ended March 31, 2015*", "*General Development of the Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March*

*31, 2017*", "*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 detailed summary of activities for Bengal's Australian properties.

ATP 752, Queensland, Australia

In the fiscal year ended March 31, 2017, the Corporation and its joint venture partners completed the Cuisinier 2016 five well drilling campaign on ATP 752 Barta Block Cuisinier area. The 2016 drilling campaign consisted of five wells commenced on July 21, 2016 and all five wells were cased as potential Murta oil wells. One of these wells was a successful exploration well and four were successful development wells. Completion of four of these five wells commenced in December 2016.

Four of the five wells drilled during fiscal 2017 were connected in May 2017 with initial combined production rates of approximately 245 bopd (gross). These initial rates are less than pre-connection expectations, and continued optimization and well cleanup work is ongoing. With recent positive results from fracture stimulation programs, Bengal and its joint venture partners will review the 2016 wells for stimulation in addition to planning fracture programs to occur immediately after completion in future drilling campaigns. In Bengal's opinion, operational delays experienced between completion and tie-in during the 2017 campaign may have been a contributor to longer well clean up timing and on initial reservoir performance. Bengal will continue to closely monitor production rates of the newly connected wells.

See "*General Development of the Business – Fiscal Year Ended March 31, 2015, 2017*" and "*Statement of Reserves Data – Other Oil and Gas Information – Principal Properties*".

Tookoonooka - ATP 732

A technical review and high grading of the current prospect inventory has continued with some priority areas identified. There are currently no outstanding commitments on this permit.

See "*General Development of the Business – Fiscal Year Ended March 31, 2017*" *and* "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties* ".

ATP 934 Barrolka Permit

In 2016, Bengal completed the geological and geophysical interpretation of the permit with a total of five prospect areas identified. Further in depth technical work on existing 2D seismic is ongoing with results of this work expected mid-year 2017.

See "*General Development of The Business – Fiscal Year Ended March 31, 2017*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties – ATP 934 Barrolka Permit*".

ATP 752 Wompi

Other than application for and approval of the Potential Commercial Area 155 ("**PCA 155**") no other work was carried out on this permit by the Corporation during the fiscal year ended March 31, 2017.The results of an Extended Production Test ("**EPT**") of the planned Nubba-1 well and subsequent reserves confirmation would have implications on any required appraisal on the newly granted PCA 155 and whether the reserves from this well could justify commercialization on a standalone basis. The timing of the EPT is to be determined by the operator.

See "*General Development of The Business – Fiscal Year Ended March 31, 2015 and 2017*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*".

***India***

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

Bengal and its joint venture partners provided notice on June 1, 2016 to the applicable Government of India Authorities of their intention to exit the CY-ONN-2005/1 exploration block. No new activity occurred on the CY-ONN-2005/1 block. Relinquishment negotiations with the regulator are ongoing. See "*General Development of the Business – Fiscal Year Ended March 31, 2017*".

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

In August 2014, Bengal completed early relinquishment on the off shore block with the regulator after establishing insufficient merit in the oil and gas potential of this permit to justify further exploration expenditures. Under the terms of the PSC related thereto, in the event Bengal did not complete the minimum work program it was required to pay liquidated damages in lieu of the work program. This payment was made to the Directorate General of Hydrocarbons in September 2014 in the amount of approximately $150,000.

***Canada***

No new activity occurred on the Oak property in British Columbia.

**Production Estimates**

The following tables disclose, by product type, the total volume of the Corporation's gross production estimated by GLJ for the fiscal year ended March 31, 2018:

| From Gross Proved Reserves: | Light Crude Oil and Medium Crude Oil (Bbls/d) | Heavy Crude Oil (Bbls/d) | Conventional Natural Gas (Mcf/d) | Natural Gas Liquids (Bbls/d) | BOE (BOE/d) | % |
|---|---|---|---|---|---|---|
| **Total** | **411** | **-** | **-** | **-** | **411** | **100** |
| **From Gross Proved plus Probable Reserves** | | | | | | |
| **Total** | **571** | **-** | **-** | **-** | **571** | **100** |

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 | | | |
|---|---|---|---|---|
| | **2017** | | **2016** | |
| | 31-Mar | 31-Dec | 30-Sep | 30-Jun |
| **AVERAGE DAILY PRODUCTION(1)** | | | | |
| Light Crude Oil and Medium Crude Oil (Bbls/d) | 344 | 355 | 386 | 431 |
| Natural Gas Liquids (Bbls/d) | 0 | 0 | 0 | - |
| Conventional Natural Gas (Mcf/d) | 0 | 0 | 0 | - |
| **Total (BOE/d)** | **344** | **355** | **386** | **431** |
| | | | | |
| **AVERAGE PRICE RECEIVED (NET OF TRANSPORTATION)** | | | | |
| Light Crude Oil and Medium Crude Oil ($/Bbls) | 70.40 | 71.28 | 64.72 | 63.44 |
| Natural Gas Liquids ($/Bbls) | - | - | - | - |
| Conventional Natural Gas ($/Mcf) | - | - | - | - |
| **Total ($/BOE)** | **70.40** | **71.28** | **64.72** | **63.44** |
| | | | | |
| **ROYALTIES PAID** | | | | |
| Light Crude Oil and Medium Crude Oil ($/Bbls) | (11.21) | (1.44) | 0.96 | 3.75 |
| Natural Gas Liquids ($/Bbls) | - | - | - | 0 |
| Conventional Natural Gas ($/Mcf) | - | - | - | 0 |
| **Total ($/BOE)** | **(11.21)** | **(1.44)** | **0.96** | **3.75** |
| | | | | |
| **PRODUCTION COSTS** | | | | |
| Light Crude Oil and Medium Crude Oil ($/Bbls) | 31.89 | 38.93 | 33.47 | 36.12 |
| Natural Gas Liquids ($/BOE) | 0 | - | - | - |
| Conventional Natural Gas ($/BOE) | 0 | - | - | - |
| **Total ($/BOE)** | **31.89** | **38.93** | **33.47** | **36.12** |
| | | | | |
| **NETBACK RECEIVED(2)(3)** | | | | |
| Light Crude Oil and Medium Crude Oil ($/Bbls) | 81.09 | 69.02 | 67.30 | 56.09 |
| Natural Gas Liquids ($/BOE) | - | - | - | - |
| Conventional Natural Gas ($/BOE) | - | - | - | - |
| **Total ($/BOE)** | **81.09** | **69.01** | **67.30** | **56.09** |

Notes:
(1) Conventional natural gas volumes are non-associated sales gas volumes.

(2) The totals shown above may not match the corporate totals due to rounding.

The following table indicates Bengal's average daily production from its important fields, and in total, for the year-ended March 31, 2017**:**

| | Light Crude Oil and Medium Crude Oil (Bbls/d) | Heavy Crude Oil (Bbls/d) | Conventional Natural Gas (Mcf/d) | NGLs (Bbls/d) | BOE (BOE/d) |
|---|---|---|---|---|---|
| **Total** | **379** | **-** | **-** | **-** | **-** |
| Australian Properties: Cuisinier | 379 | - | - | - | - |

Note:
(1) Numbers may not add due to rounding.

The Corporation's production for the year ended March 31, 2017 was 100% light quality crude oil (32° API or greater).

For the twelve months ended March 31, 2017, approximately 100% of the Corporation's gross revenue was derived from light crude oil and medium crude oil production, 0% was derived from heavy crude oil production and 0% was derived from conventional 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 any other business considerations that 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 102,266,694 Common Shares 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 6,032,500 options to purchase Common Shares outstanding with an average exercise price of $0.25, of which 1,808,756 options to purchase Common Shares are vested.

The holders of Common Shares are entitled to receive notice of, to attend and vote at any Shareholders meetings of the Corporation, 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 of 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 |
|---|---|---|---|
| 2016 | | | |
| March | 0.145 | 0.105 | 490,935 |
| April | 0.15 | 0.105 | 2,373,147 |
| May | 0.18 | 0.13 | 735,121 |
| June | 0.225 | 0.155 | 691,361 |
| July | 0.225 | 0.17 | 326,660 |
| August | 0.21 | 0.16 | 325,618 |
| September | 0.21 | 0.155 | 711,231 |
| October | 0.24 | 0.18 | 822,190 |
| November | 0.20 | 0.12 | 1,045,030 |
| December | 0.17 | 0.125 | 2,149,075 |
| 2017 | | | |
| January | 0.225 | 0.15 | 1,765,826 |
| February | 0.20 | 0.145 | 899,608 |
| March | 0.15 | 0.125 | 880,422 |
| April | 0.17 | 0.13 | 774,112 |
| May | 0.155 | 0.13 | 688,822 |
| June (1 to 26) | 0.145 | 0.10 | 1,756,933 |

### Escrowed Securities

As of March 31, 2017, 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 current 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<br>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. |

| | | | |
|---|---|---|---|
| Ian J. Towers(3)<br>Calgary, Alberta, Canada | Director (Chairman) | November 24, 2005 | Independent businessman since April 2015. Prior thereto, President, Chief Executive Officer and a Director of Dolomite Energy Inc. from February 2005 to April 2015. |
| Peter D. Gaffney(2)(3)<br>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 Upfolds Ltd., a UK company from September 2013 to present to August 2016. |
| James B. Howe(1)<br>Calgary, Alberta, Canada | Director | November 24, 2005 | From January 1982 to present, President of Bragg Creek Financial Consultants Ltd. (a private financial consulting corporation). Director of Ensign Energy Services Inc. and Pason Systems Inc. |
| Brian Moss(2)(3)<br>Calgary, Alberta, Canada | Director | January 6, 2012 | Appointed President and Chief Executive Officer Crown Point Energy Inc. (formerly Crown Point Ventures Ltd.), a public oil and gas company on November 9, 2016, Prior thereto Executive Vice President and Chief Operating Officer from June 2012 to November 2016. Director of Crown Point Energy Inc. from May 2012 to April 2015. 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. |
| Robert Steele(1)(3)<br>Calgary Alberta, Canada | Director | August 27, 2010 | Independent businessman since March 2010. Prior thereto, a member of the board of directors of Raise Production Inc. (formerly Global Energy Services Ltd.) from June 2011 to October 2015. Director of Marquee Energy Ltd (formerly Skywest Energy Ltd.) from June 2010 to June 2013. |
| William (Bill) Wheeler(1)<br>Vancouver, British Columbia, Canada | Director | January 6, 2012 | Private investor. Co-founder of Leith Wheeler Investment Counsel. Director and President of Texada Capital Management Ltd., a private investment company, since September 2011. |
| Richard Edgar<br>Calgary, Alberta, Canada | Executive Vice President | N/A | Executive Vice President of Bengal since September 2014. President of Poplar Creek Resources Inc., a public oil and gas exploration and development company, since July 2009. Director of Shelton Canada Corporation from December 2009 to present. From June 2012 to June |

| | | | |
|---|---|---|---|
| | | | 2014 a director of Passport Energy Ltd. Director of Bengal from November 2002 until September 2011. |
| Jerrad Blanchard<br>Calgary, Alberta, Canada | Chief Financial Officer | N/A | Chief Financial Officer of Bengal since December 2013. Prior to its sale earlier in 2013, Mr. Blanchard served as the CFO of Winstar Resources Ltd. Prior thereto, he was a Manager in PricewaterhouseCoopers LLP's Audit and Assurance Group. |
| Gordon MacMahon<br>Calgary, Alberta, Canada | Vice President, Exploration | N/A | Vice President, Exploration of Bengal since September 2011. Independent consultant to oil and gas industry from March 2008 to August 2011. |

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 27, 2017, the directors and officers of Bengal set forth above, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 37,207,331 Bengal Shares or approximately 36.4% of the issued and outstanding Bengal Shares, and 42,617,331 Bengal Shares or approximately 39.3% of the issued and outstanding Bengal Shares on a fully diluted basis (including the exercise of outstanding Options).

**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 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. In addition, Mr. Edgar was a director and officer of Poplar Creek Resources Inc. ("**PCK**") when the company was subject to cease trade orders by the Alberta Securities Commission (the "**ASC**"), British

Columbia Securities Commissions and Ontario Securities Commissions on May 9, 2014 for failure to file annual audited financial statements within the time frame allowed.

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

Dr. Moss was an independent director of Richards Oil & Gas Limited ("**Richards**") 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. Richards was issued cease trade orders by the ASC, British Columbia Securities Commission and Ontario Securities Commission 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. Richards was granted protection from its creditors under the *Bankruptcy and Insolvency Act* ("**BIA**") on May 5, 2010. Richards' shares were de-listed from the TSX Venture Exchange on July 9, 2010 for failure to pay corporate sustaining fees. Richards 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 Ontario Securities Commission 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 Richards, 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), William (Bill) Wheeler and Robert Steele. The members of the Audit Committee are all 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 Ensign Energy Services Inc. and Pason Systems Inc. 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 with a degree in Electrical Engineering from the University of Saskatchewan in 1970. Mr. Steele is a professional engineer and independent businessman. He was a member of the Board of Directors of Raise Production Inc. (formerly Global Energy Services Ltd.) (TSXV: RPC) from June 2011 to October 2015. From June 2010 to June 2013, he was a Director of Marquee Energy Ltd. (TSXV: MQL) (formerly Skywest Energy Ltd.).

*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 Leith Wheeler Investment Counsel in 1982. He also sits on the Board of Directors 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 31, 2017 | Financial Year Ending March 31, 2016 |
|---|---|---|
| Audit Fees(1) | $95,000 | $105,000 |
| Audit Related Fees(2) | $- | $- |
| Tax Fees(3) | $9,630 | $14,227 |
| All Other Fees(4) | $- | $- |

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 the Corporation.

## 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, 2017, Bengal employed nine full-time employees and three part-time consultants at the head office. The Corporation also uses consulting services from a number of service providers on an as needed 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 Professional Accountants, Suite 3100, 205 – 5 Avenue S.W., Calgary, Alberta T2P 4B9.

Valiant Trust Company, 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.

During the year ended March 31, 2017, 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

Other than as set forth herein, 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 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.

Subsequent to the Rights Offering, which closed on December 29, 2016, Mr. Wheeler currently owns, directly or indirectly, or exercises control or direction over 26,891,489 Common Shares, representing approximately 26.3% of the total issued and outstanding Bengal Shares as at the date of this Annual Information Form See "*General Development of the Business — Recent Developments — General*".

## 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 GLJ, 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 GLJ 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 GLJ prepared the report, valuation, statement or opinion or any time thereafter. KPMG LLP, Chartered Professional Accountants, are independent with respect to the Corporation within the meaning of the relevant Rules of and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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 with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, British Columbia and foreign countries, such as India and Australia, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada, India and Australia.

## Pricing and Marketing

### *Canada*

*Oil*

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, 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. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act (Canada)* (the "***Prosperity Act***") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

*Natural Gas*

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. 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 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 $m^3$ per day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas requires an exporter to obtain an export licence from the NEB.

### *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.

## The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force 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. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

**Royalties and Incentives**

*General*

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights 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 carved out of the working interest owner's interest, from time to time, 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.

The Canadian federal government has signaled that it will *inter alia* phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

*British Columbia*

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, 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 classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. 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. Royalties on natural gas liquids are levied at a flat rate of 20% of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the applicable freehold production tax is based on the volume of monthly production, and is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, 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. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale depending on the total number of hectares owned by the entity.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to 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 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *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;

- *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 a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 $m^3$ for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 $m^3$;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 $m^3$ per metre of depth for exploratory wildcat wells and less than 11 $m^3$ per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 $m^3$. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; 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 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 that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

*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. Beginning July 1, 2012, PRRT became applicable to all Australian onshore and offshore oil and gas projects, including coal seam gas and oil shale projects. 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 deductible 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 cannot 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.

**Land Tenure**

*Canada*

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. 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. Private ownership of oil and natural gas also exists in such provinces 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.

Each of the provinces of Alberta, British Columbia and Saskatchewan have 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 licence. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the 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 in Queensland or PEL in South Australia 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. Recent changes to the Petroleum and Gas Act announced by the Queensland State Government on May 28, 2014 may extend onshore ATP work permits by two years to six years. 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. All phases of the oil and gas exploration, development and production activities are regulated in varying degrees by the Australian regulatory authorities. 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 Licences' 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).

a) Queensland - Potential Commercial Area (PCA)

Another feature of the land tenure system in Queensland is that as an ATP reaches the end of its term, an application can be made to have an area of the ATP declared as a potential commercial area (PCA) so that the holder can evaluate the potential production and market opportunities for the estimated resource.

The PCA is a way of retaining an area of an ATP beyond its term to provide extra time to commercialise the estimated resource. The maximum term for an ATP is 12 years, while the application for the declaration for the PCA can be for up to 15 years.

A PCA application must include a commercial viability report that shows that the area is likely to be commercially viable within 15 years. The application must also include an evaluation program showing how the holder will overcome any factors inhibiting the commercial viability of the project.

When an area is declared as a PCA, it remains part of the ATP. When the PCA expires, the declared area ceases to be part of the original ATP.

b) South Australia – Permit Retention Licences (PRL)

The PRL scheme is offered by the South Australian Government as a mechanism to recognise the life-cycle for finding, appraising, developing and producing resources. The scheme involves permit operators entering into individual or grouped PRLs to enable greater flexibility for optimising investments and expanding portfolio management options.

PRLs can be sought for covered areas recognised by the Department of State Development (DSD) as lying within known proven productive oil or gas play trends in the Cooper Basin. There is also a provision to include other areas outside of DSD's interpretation of the play, subject to agreement by DSD. A common operator across the covered area is required.

The PRL scheme provides for minimum eligible expenditure targets over the covered areas. DSD has set a minimum expenditure level of $4,500 per km2 per annum for oil acreage, while the minimum expenditure level within a gas play is on a negotiated bid basis, and is expected to fall somewhere between $7,000 to $9,000 per km2. In considering these negotiated bids DSD will also take into account the prospectivity of the permit areas and therefore not all permits are expected to fall within the higher target range. Licence areas are currently limited to 100 km2 so in many cases multiple PRL applications will be required to cover the whole of an original Petroleum Exploration Licence (PEL).

Any residual work program yet to be completed under a PEL will need to be carried into the relevant PRLs without variation to timing. This is to preserve the integrity of the work program bidding system for PELs. PRLs are granted for an initial five year period with two five-year extension options, subject to meeting or exceeding the minimum expenditure target

Potential benefits of the scheme include: flexibility of timing of spend over five years; reduced threshold for PRL granting; and security of tenure (potentially up to 15 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 a 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.

**Production and Operation Regulations**

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, Bengal must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

**Environmental Regulation**

*Canada*

The oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environmental assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

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.

*British Columbia*

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

*Australia*

In Australia, the Queensland Wild Rivers legislation was enacted to regulate new development and the extraction 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.

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.

During 2014, the Wild Rivers legislation was repealed and replaced with the Regional Planning Interests Regulations. Bengal has previously been advised by the regulating authority its Environmental Authority for ATP 934 had contained a condition that for petroleum activities to be carried out in a wild river area, the activities must comply with the conditions stated for relevant petroleum activities in the wild river declaration for that area. As such, Bengal had been required to comply with relevant conditions from the former Cooper Creek Basin Wild Rivers Declaration. The *Wild Rivers Act 2005* ("**WRA**") was repealed on October 1, 2014 with the commencement of the *State Development, Infrastructure and Planning, (Red Tape Reduction)* and other *Legislation Amendment Act 2014*. The intent of the legislation was to carry forward the environmental protections and land use policy outcomes of the WRA within the new land use planning and development assessment framework of the *Regional Planning Interest Act 2014* (RPI Act). Transitional provisions in sections 715B - D *Environmental Protection Act 1994* ("**EP Act**") (2015 Act No. 4) permitted the following:

- Wild River conditions on environmental authorities ("**EAs**") issued before the repeal of the WRA will continue in effect for one year (section 715B EP Act), after which the conditions become unenforceable; and

- EAs issued prior to the repeal of WRA may be amended during the transitional period (October 1, 2014 - September 30, 2015) to replace Wild River conditions with conditions that provide equivalent environmental protection, without agreement or appeal rights of the EAs (section 715B(4) of the EP Act).

As such, a letter was sent to Bengal on June 18, 2015 advising that the WRA was repealed on October 1, 2014 and all existing EAs that referenced wild rivers were required to be amended by September 30, 2015 to achieve equivalent environmental protection.

On September 22, 2015, a decision notice was issued to Bengal with details of all the changes made to the EAs and confirmation that there had been no change in the scope of activities authorized on EPVX01704113 as a result of this amendment.

In effect, the conditions from the Cooper Creek Basin Wild Rivers Declaration (which Bengal was already required to meet), was simply moved onto the Bengal EAs and any references to the former Wild River areas and terms updated and any duplicate conditions deleted. A map was inserted into the EAs to limit the effect of the revised conditions to only within areas which used to be former wild rivers but are now within the strategic environmental area. There was no change in the requirements for the activity, as the amendment of the EAs was limited to include only those conditions that were previously referenced to in the Wild River declaration. This has resulted in an additional number of conditions appearing on the Corporation's EAs; however, there has been no change in the scope of activities authorized.

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.

Further, on February 29, 2014 and January 1, 2015, certain changes to the Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 (the "**Environment Regulations**") came into effect in Australia. The February 28, 2014 amendments to the Environmental Regulations incorporate changes necessary for the National Offshore Petroleum Safety and Environmental Management Authority ("**NOPSEMA**") to retain the environmental safeguards of the *Environmental Protection and Biodiversity Conservation Act 1999* and provide: (i) clarified environmental assessment and implementation strategy requirements for environment plan submissions; (ii) clarified and strengthened environmental performance and incident reporting requirements; (iii) strengthened duties and responsibilities of the titleholder; and (iv) requirements for 'offshore project proposal' submissions for new large scale development projects in Commonwealth waters. One specific amendment was the change from the "operator" being responsible for compliance with Environment Regulations, to the "titleholder".

The January 1, 2015 changes reflect the Australian Government's response to the June 2010 Report of the Montara Commission of Inquiry, including amendments to the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (the "**OPGGS Act**") to strengthen and clarify the responsibilities of titleholders undertaking petroleum activities.

Amendments to the OPGGS Act became effective on November 29, 2013. The previous requirement to hold insurance was broadened by the amendments to require titleholders to maintain sufficient financial assurance to meet the costs, expenses and liabilities that may arise in connection with carrying out petroleum activities among other things. From January 1, 2015, the Environment Regulations also provide that the NOPSEMA must be reasonably satisfied that a titleholder is compliant with certain provisions of the OPGGS Act prior to accepting an environment plan ("**EP**") or revised EP that was submitted on or after January 1, 2015.

Effective April 27, 2016, the Queensland Parliament significantly broadened the reach of its environmental law by passing the *Environmental Protection (Chain of Responsibility) Amendment Act 2016* (the "**Act**"). The Act was introduced to compel responsible persons connected to corporations in financial distress to meet environmental responsibilities. The Act amends the *Environmental Protection Act 1994* (Qld) to empower the Queensland Department of Environment and Heritage Protection ("**DEHP**") to issue related persons of the Operators with environmental protection orders ("**EPO**") and cost recovery notices.

An EPO may require the related person to: take action to prevent or minimize the risk of environmental harm, rehabilitate or restore land because of environmental harm or give the DEHP a bank guarantee or other form of financial assurance to secure the related person's compliance with the EPO. A failure to comply with an EPO is a criminal offence punishable by a fine. If the non-compliance is willful, a prison sentence may also be imposed. Additionally, breach of an EPO will enable the DEHP to step in and remediate a site, and then recover its rehabilitation costs from the EPO recipient.

The Act also confers power on the DEHP to require the provision of a financial assurance or bond in circumstances where an Operator proposes transferring an environmental authority it holds to another entity and compel persons to answer questions relating to a suspected offence against the new environmental laws.

The Act seeks to maintain accountability for damaging environmental practices. Any person or entity with a connection to a company ("**Operator**") that carries out environmentally relevant activities in Queensland, should consider the risk liability posed by the Act.

Other than the potential effects on ATP 732 and ATP 934 as a result of the repealed Wild Rivers legislation and implementation of the Regional Planning Interests Regulations noted above, Bengal is not aware of any negative or positive effects environmental regulations will have on its activities.

**Liability Management Rating Programs**

*British Columbia*

In British Columbia, the Commission oversees the Liability Management Rating Program (the "**BC LMR Program**"), designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the Commission determines the required security deposits for permit holders under the *OGAA*. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the *OGAA*.

*Queensland Australia*

In Queensland, recent amendments to the Environmental Protection Act-1994 have been made. These amendments require any Operating Company with an approved Environmental Authority to lodge a Financial Assurance (“FA”) deposit either in the form of cash in Australian currency or in the form of a Bank Guarantee. Financial Assurance is based on the likely costs and expenses that the Queensland Government may incur for remediation of surface conditions in the event of default by the Operator. The calculation of the amount of Financial Assurance must be done in accordance with the methodology approved by the Queensland Government. Financial Assurance guarantees remain active until the Operating Company completes remediation. Modifications to the current FA legislation are currently under review.

**Climate Change Regulation**

*Federal*

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

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, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

*Australia*

On July 17, 2014, the carbon tax repeal legislation received the Royal Assent, abolishing the carbon pricing mechanism effective July 1, 2014. As a result, no new carbon tax liabilities will be incurred from July 1, 2014. However, no carbon tax liabilities that were incurred before June 30, 2014 will be removed.

On June 18, 2014, the *Carbon Farming Initiative Amendment Bill 2014* was introduced into Parliament and it received Royal Assent on November 24, 2014. The legislation establishes the Emissions Reduction Fund to replace the carbon tax and provide a transition for the Carbon Farming Initiative by amending the: *Carbon Credits (Carbon Farming Initiative) Act 2011* to: provide for the Clean Energy Regulator to conduct auctions and enter into contracts to purchase emissions reductions; enable a broader range of emissions reduction projects to be approved; and amend the project eligibility criteria and processes for approving projects and crediting carbon credit units; and *Australian National Registry of Emissions Units Act 2011*, *Clean Energy Regulator Act 2011* and *National Greenhouse Energy and Reporting Act 2007* to make consequential amendments. As of December 12, 2014, the Carbon Farming Initiative has been integrated with the Emissions Reduction Fund.

The objective of the Emissions Reduction Fund is to help Australia to meet its emissions reduction target of five percent below 2000 levels by 2020. The Emissions Reduction Fund will build on the Carbon Farming Initiative by offering emissions reduction opportunities to a range of sources beyond the land sector. Through the Emissions Reduction Fund auction arrangements, the Australian Government will purchase Australian carbon credit units ("**ACCUs**") from existing Carbon Farming Initiative projects that are competitive at an auction. This will allow existing participants in the Carbon Farming Initiative to secure a return from eligible projects.

*India*

On June 30, 2008, Prime Minister Manmohan Singh released India's first National Action Plan on Climate Change 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. Action plans on climate change are also being put in place at a State level. In 2014, the Ministry of Environment and Forests launched a Climate Action Programme that will focus on assessing the impact of climate change in vulnerable areas, capacity building and setting up of an institute for conducting climate change studies. The Climate Change Action Programme will have the National Action Plan on Climate Change and the state action plans as part of it.

## 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. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.**

### Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, for which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by Bengal will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of the Corporation will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that Bengal will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Bengal may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

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

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Bengal attempts to minimize exploration, development and production risks by utilizing a high-end technical team with extensive experience and multidisciplinary skill sets to assure the highest probability of success in its drilling efforts. Bengal's collaboration of a team of seasoned veterans in the oil and gas business, each with a unique expertise in the various upstream to downstream technical disciplines of prospect generation to operations, provides the best assurance of competency, risk management and drilling success. A full cycle economic model is utilized to evaluate all hydrocarbon prospects. Detailed geological and geophysical techniques are regularly employed including 3D seismic, petrography, sedimentology, petrophysical log analysis and regional geological evaluation.

**Weakness in the Oil and Gas Industry**

Recent market events and conditions, including global excess oil supply, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry relative to historic highs. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive 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, labor disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the 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 the Corporation's operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Bengal. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Bengal, which can result in the Corporation having to pay significant penalties and fines. 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.

**Prices, Markets and Marketing**

Oil and natural gas are commodities that have prices determined based on world demand, supply and other factors, all of which are beyond the control of the Corporation. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of Bengal's oil and gas reserves. Bengal might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Bengal's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition to establishing markets for its oil and natural gas, Bengal must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Bengal will be affected by numerous factors beyond its control. The ability of the Corporation to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Bengal will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

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 and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A 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 because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All 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 production, development and exploration activities. 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 because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions 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.

See "*Weakness in the Oil and Gas Industry*".

**Market Price of Common Shares**

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares 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 weakened slightly 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. The Australian dollar to US dollar exchange rates may have a material impact on operations. The Australian dollar to Canadian dollar exchange rates do not materially impact the Corporation's overall profitability.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

Additionally, an increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and could negatively impact the market price of the Common Shares.

**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 or prices fall significantly lower than projected;
- 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 or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, 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. Failure to obtain 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. Due to the conditions in the oil and gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, the Corporation 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, 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 affected materially and adversely 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. Alternatively, any available financing may be highly dilutive to existing shareholders. 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 shares of other entities. 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 in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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 natural gas;
- royalty rates; and
- 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 and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often 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. 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 and 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, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

**Seismic Data**

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures, as well as direct eventual hydrocarbon indicators, and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and the Corporation could incur losses as a result of such expenditures. As a result, some of the Corporation's drilling activities may not be successful or economical, and the Corporation's overall drilling success rate or its drilling success rate for activities in a particular area could decline, which could have a material adverse effect on expected results of operations and financial condition of the Corporation.

**Substantial Capital Requirements**

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Bengal may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Bengal to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Bengal's ability to expend the necessary capital to replace its reserves or to maintain its production. If Bengal's funds from operations are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Corporation.

Bengal monitors and updates its cash projection models on a regular basis which assists in the timing decision of capital expenditures. Farm outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that the Corporation wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal's capital program.

**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 overruns 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, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;

- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- 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 be unable to market the oil and natural gas that it produces effectively. 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.

**Infrastructure**

Infrastructure development in many of the countries in which the Corporation operates is limited. These factors may affect the Corporation's ability to explore and develop its properties and to store and transport its oil and gas production. There can be no assurance that future instability in one or more of the countries in which the Corporation operates, actions by companies doing business there, or actions taken by the international community will not have a material adverse effect on the countries in question and in turn on the Corporation's financial conditions or operations.

**Aboriginal Claims**

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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

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.

All of Bengal's Native Title Agreements in Australia are in good standing and no native claims have been received or contemplated as of the date hereof.

Bengal is not aware of any Aboriginal Claims existing in onshore or offshore 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**

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry 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 natural gas operations, the Corporation will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect the Corporations business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

*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, including acceptance of the Corporation's notice of intention to exist the CY-ONN-2005/1 exploration block delivered on June 1, 2016. As a consequence, such notice must be reviewed and 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.

**Competition**

The Corporation actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and personnel resources than Bengal. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. Bengal's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The Corporation's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

**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. Certain oil and natural 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 addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation as the demand for natural gas rises during cold winter months and hot summer months. 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 addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. 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 affect 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

**Health, Safety and 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.

**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 personnel 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 a defect in the chain of title will not arise to defeat the Corporation's claim. The actual interest of the Corporation in properties may, accordingly, vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, 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 the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

**Insurance**

Bengal's involvement in the exploration for and development of oil and gas properties may result in the Corporation becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Bengal has insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, 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 such uninsured liabilities would reduce the funds available to Bengal. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bengal's financial position, results of operations or prospects.

**Breach of Confidentiality**

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

**Income Taxes**

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

**Geopolitical Risks**

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and 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 the subject of 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 on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and 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 diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so 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 may realize less on disposition than their carrying value on the financial statements of the Corporation.

**Cost of New Technologies**

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

**Operational Dependence**

Other companies operate some of the assets in which the Corporation has an interest. 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 depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, 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.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation form such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

**Royalty Regimes**

There can be no assurance that the Australian, Queensland or South Australia state governments or the Canadian federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

**Climate Change**

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG 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) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel 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 cash dividends in the future, if any, will be subject to the discretion of the Board of Directors of Bengal and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends.

**Litigation**

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition, results of operations and prospects. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition. Also see "*Legal Proceedings and Regulatory Actions*".

**Conflicts of Interest**

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of 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 to 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 . See "*Conflicts of Interest*".

**Forward-Looking Information May Prove Inaccurate**

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this annual information form.

**Expansion into New Activities**

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in Australia. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being materially adversely affected.

**Gathering and Processing Facilities, Pipeline Systems and Rail**

Bengal delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that Bengal can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in Bengal's inability to realize the full economic potential of its production or in a reduction of the price offered for Bengal's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm Bengal's business and, in turn, Bengal's financial condition, operations and cash flows. In addition, the federal government of Canada has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

A portion of Bengal's production may, from time to time, be processed through facilities owned by third parties and over which Bengal 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 have a materially adverse effect on Bengal's ability to process its production and deliver the same for sale.

**Alternatives to and Changing Demand for Petroleum Products**

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Bengal cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Bengal's business, financial condition, results of operations and cash flows.

**Liability Management**

British Columbia has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of Bengal's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirement. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

**Credit Facility Arrangements**

Bengal currently has the Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. Bengal is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that Bengal does not comply with these covenants, Bengal's access to capital could be restricted or repayment could be required. Events beyond Bengal's control may contribute to the failure of Bengal to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in Bengal being required to repay amounts owing thereunder. The acceleration of Bengal's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on Bengal that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to Bengal's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Bengal's lenders use Bengal's reserves, commodity prices, applicable discount rate and other factors, to periodically determine Bengal's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce Bengal's borrowing base, reducing the funds available to Bengal under the Credit Facility. This could result in the requirement to repay a portion, or all, of Bengal's indebtedness.

If the Corporation's lenders require repayment of all or portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

**Political Uncertainty**

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

**Information Technology Systems and Cyber-Security**

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation’s business, financial condition and results of operations.

## 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**

**Report of Management and Directors on Reserves Data and Other Information**

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.

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 the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources 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 27th day of June, 2017.

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

(signed) "*Jerrad Blanchard*"
Jerrad Blanchard
Chief Financial Officer

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

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

**SCHEDULE "B"**
**FORM 51-101F2**
**REPORT ON RESERVES DATA**
**BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

**Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor**

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

1. We have evaluated the Corporation's Reserves Data as at March 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2017, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of 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 Corporation evaluated for the year ended March 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's board of directors:

| Independent Qualified Reserves Evaluator or Auditor | Effective Date of Evaluation Report | Location of Reserves (Country or Foreign Geographic Area) | Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – CAN$) | | | |
|---|---|---|---|---|---|---|
| | | | Audited ($M) | Evaluated ($M) | Reviewed ($M) | Total ($M) |
| GLJ Petroleum Consultants Ltd. | March 31, 2017 | Australia | - | 118,007 | - | 118,007 |

6. 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, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

**Executed as to our report referred to above:**

GLJ Petroleum Consultants Ltd., Calgary, Alberta, dated June 8, 2017.

GLJ PETROLEUM CONSULTANTS LTD.

(Originally signed by) "*Patrick Olenick*"
Per: Patrick A. Olenick, P. Eng.
Title: Manager, Engineering

**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