TSX: BNG

BENGAL ENERGY LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

MARCH 31, 2024

June 28, 2024

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ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	Mcfe	thousand feet of gas equivalent
Bbls/d	barrels per day		
NGLs	natural gas liquids		

Other

API	American Petroleum Institute
˚API	an indication of the specific gravity of oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and 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
km^2	square kilometres
M	metres
MBOE	1,000 barrels of oil equivalent
$M	thousands of dollars

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 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
Acres	Square metres	4046.86
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
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:

"**2022 Private Placement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – Private Placement Financing*".

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**AHK Australien**" means the German-Australian Chamber of Industry and Commerce.

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

"**AVO**" has the meaning ascribed thereto under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Exploration and Development Activities – ATP 934 Barrolka East Permit"*.

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

"**Bengal Australia**" means Bengal Energy (Australia) Pty Ltd., a wholly owned subsidiary of Bengal incorporated in Australia.

"**Canop IRV**" has the meaning ascribed thereto under the heading "*Background and Corporate Structure – Name, Address and Incorporation*".

"**Caracal 1 Well**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PCA 332 Tookoonooka (controlling permit ATP 732)*".

"**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.

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

"**DSU**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Additional Information Relating to Reserves Data – Undeveloped Reserves – Proved Undeveloped Reserves*".

"**Durham Downs East Block**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – Santos Farm-in – ATP 934 Barrolka East Permit*".

"**Ghina Well**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)*".

"**GLJ**" means GLJ Ltd.

"**GLJ Report**" means the report of GLJ dated June 12, 2024, evaluating the oil, natural gas liquids and natural gas reserves of the Corporation as at March 31, 2024.

"**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.

"**IOR**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PCA 332 Tookoonooka (controlling permit ATP 732)*".

"**JV**" means joint venture.

"**Legbar 1 Well**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – Santos Farm-in – ATP 934 Barrolka East Permit*".

"**LWP**" means Later Work Program, which provides an ATP holder the opportunity to further refine the exploration potential proposed under the ATP.

"**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*.

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*.

"**NOPTA**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Properties with No Attributable Reserves – Offshore Australia – AC/RL 10 (formerly AC/P24) Ashmore Cartier Area, Timor Sea, Offshore Australia*".

"**PCA**" means Potential Commercial Area.

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

"**PL**" means Production License.

"**PPL**" means Petroleum Production License.

"**Preferred Shares**" means the preferred shares, issuable in series, in the capital of Bengal.

"**Ramses 2 Well**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)*".

"**Reserves Data**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data*".

"**RL**" means Retention License.

"**Santos**" means Santos QNT Pty Ltd.

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

"**Statement**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other Oil and Gas Information*".

"**Tigris-1**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2024 – PCA 332 Tookoonooka (controlling permit ATP 732)(100% WI)*".

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

"**Wareena 1 Well**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline(100% WI)*".

"**Wareena 5 Well**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline(100% WI)*".

"**Wareena Wells**" has the meaning ascribed thereto under the heading "*General Development of the Business – Fiscal Year Ended March 31, 2022 – PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline(100% WI)*".

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, 2024.

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", "potential" 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, beliefs or expectations 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:

- the Corporation's strategy to achieve per share growth in cash flow, production and reserves while establishing an attractive portfolio of future drilling and exploration opportunities;
- the Corporation's intention to grow its resource and reserves base within its existing acreage and to continue building strategic alliances with appropriate local partners and large operators in Bengal's primary areas of focus;
- production and performance characteristics of the Corporation's oil and natural gas properties and the anticipated benefits therefrom;
- the expectation that the Corporation will continue to be active in identifying and analyzing potential production acquisition opportunities;
- expectations with respect to the Corporation's growth initiatives in Australia;
- the Corporation's intention to consider asset and corporate acquisition opportunities that meet its business parameters;
- the Corporation's belief that it has the management skills and resources necessary to achieve its stated objectives;
- the anticipated criteria that the Corporation will consider when reviewing potential drilling or acquisition opportunities;
- the Corporation's belief that its competitive position is similar to that of other oil and natural gas producers of a similar size and production profile;
- expectations regarding the further dewatering work planned at the Wareena Wells;
- expectations with respect to the operational sustainability study from 2022 and the Corporation's subsequent feasibility studies into carbon farming with the landholders of the Corporation's tenements;
- the Corporation's belief with respect to the electrification of well sites using renewable energy;
- the Corporation's beliefs and expectations with respect to the reduction of the Corporation's carbon footprint in the Corporation's operations;
- expectations with respect to raw gas supplied from the Wareena 5 Well;
- expectations with respect to the results of the Corporation's water injection program at the Cuisinier field;
- expectations with respect to the Cuisinier field operator's drilling program;
- expectations with respect to further drilling and operations at Tigris-1;
- expectations with respect to analogous discoveries located in the Tintaburra and Toobunyah fields;
- expectations with respect to the continued integration by the Corporation of subsurface data from the PLs;
- the Corporation's belief that it will continue to actively seek and assess potential farm-in partnerships with third-party industry participants and other financing arrangements;
- expectations with respect to the new legislation enacted for Queensland;
- terms of and expectations with respect to the binding term sheet agreement entered into by Bengal with an undisclosed party;
- 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;
- drilling plans and strategy including, without limitation, the timing, location and targeted zones of current and future wells;
- the expectation that spreading out the Corporation's development program over several years will optimize capital allocation and facility utilization;
- expectations with respect to the Corporation's development of the Cuisinier field, including, without limitation, the anticipated timing of drilling based on the Cuisinier operator's field development plan;
- expectations with respect to the Corporation's tenements at Wareena, Ghina, Ramses and Karnak, as well as completion activity and further exploration based on the Nassarius 3D seismic program on PCA 332;
- the expected timing of certain wells to resume production;

- expectations with respect to the Corporation's work programs planned on its Barrolka East Permit natural gas assets;
- the timing expectations for the conversion of proved undeveloped reserves into developed reserves, as well as the timing of development of certain probable undeveloped reserves;
- expectations with respect to development costs and operating costs;
- the expectation that the Corporation will use internally generated cash flow from operations, debt, and new equity issues, if available on favourable terms, to finance its capital expenditure program;
- expectation with respect to the wells at Wareena and the Katandra – 1A discovery well;
- expectations regarding the farm-in interest on certain 3D defined drilling targets on PCA 332 that are being sought by the Corporation and the anticipated development opportunities at PCA 332;
- potential issues in the design of completion programs due to high viscosity;
- expectations with respect to potential future land relinquishments;
- estimated abandonment and reclamation costs and the timing thereof;
- supply and demand for oil and natural gas and commodity prices;
- 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 ATPs or extensions thereof;
- evaluations of future net production revenues based on forecast prices and costs;
- the intention to add additional professional and administrative staff as the need arises; and
- the time at which the Corporation expects it will begin paying current income tax.

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:

- Bengal's status as a non-operator in the Cuisinier field, including, without limitation, a failure of the Cuisinier operator to execute its field development plan on the anticipated timeline or at all;
- 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;
- volatility of oil and natural gas prices and price differentials;
- monetary inflation and increases in interest rates;
- restrictions or costs imposed by climate change initiatives and the physical risks of climate change;
- risk that the Corporation is unable to access sufficient capital from internal and external sources;
- risk 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 and use of analogous information;
- the production and growth potential of Bengal's assets is different from management's expectations;
- governmental regulation of the oil and natural gas industry;
- failure to obtain required approvals of regulatory authorities in Australia;
- 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;
- 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;

- 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;
- failure to develop the Corporation's undeveloped reserves on the timelines anticipated or at all;
- 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 SEDAR+ at www.sedarplus.ca.

With respect to forward-looking statements contained in this Annual Information Form, Bengal has made assumptions regarding, but not limited to:

- the impact of increasing competition;
- the general stability of the economic and political environment in which Bengal operates;
- operating costs;
- the ability of Bengal to obtain funding;
- 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 accuracy of the screening study completed by the AHK Australien's Energy Cluster;
- 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 timing and completion of fracturing programs and timing of production on such wells following completion of the fracturing programs;
- the timing and expectations surrounding upcoming lease relinquishments;
- the completion of seismic interpretation;
- 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 continuance of current laws and regulations;
- utilization of tax pools;
- 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.

OIL AND GAS ADVISORIES

Any references in this Annual Information Form to drill stem test results, or similar production test rates are useful in confirming the presence of hydrocarbons. However, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells, including the Wareena Wells. Accordingly, the Corporation cautions that the test results are historical and not indicative of long-term performance or ultimate recovery.

Further, this Annual Information Form includes estimates of pay thickness in the Ashmore Cartier Area, which are considered to be anticipated results or information that indicate the potential value or quantities of resources under NI 51-101. Such estimates have been prepared by management of Bengal and have not been prepared or reviewed by an independent qualified reserves evaluator or auditor. The risks associated with these estimates include, but are not limited to, the risk that Bengal's exploration and development drilling and related activities may provide different results; the risk that Bengal may encounter unexpected drilling results; the occurrence of unexpected events involved in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and the risk that if any resources are discovered that it will not be commercially viable to produce any portion thereof. There is no certainty that Bengal will achieve the estimated results or that any portion of the resources will be discovered. If discovered, there is also no certainty that it will be commercially viable to produce any portion of the resources.

ANALOGOUS INFORMATION

Certain information in this document may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to the areas in geographical proximity to prospective exploratory lands held or to be held by Bengal. Management of Bengal believes the information is relevant as it helps to define the lands characteristics in which Bengal may hold an interest. Bengal is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor and is unable to confirm that the analogous information was prepared in accordance with NI 51-101. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by Bengal and there is no certainty that the reserves data and economics information for the lands held or to be held by Bengal will be similar to the information presented herein.

BACKGROUND AND CORPORATE STRUCTURE

Name, Address and Incorporation

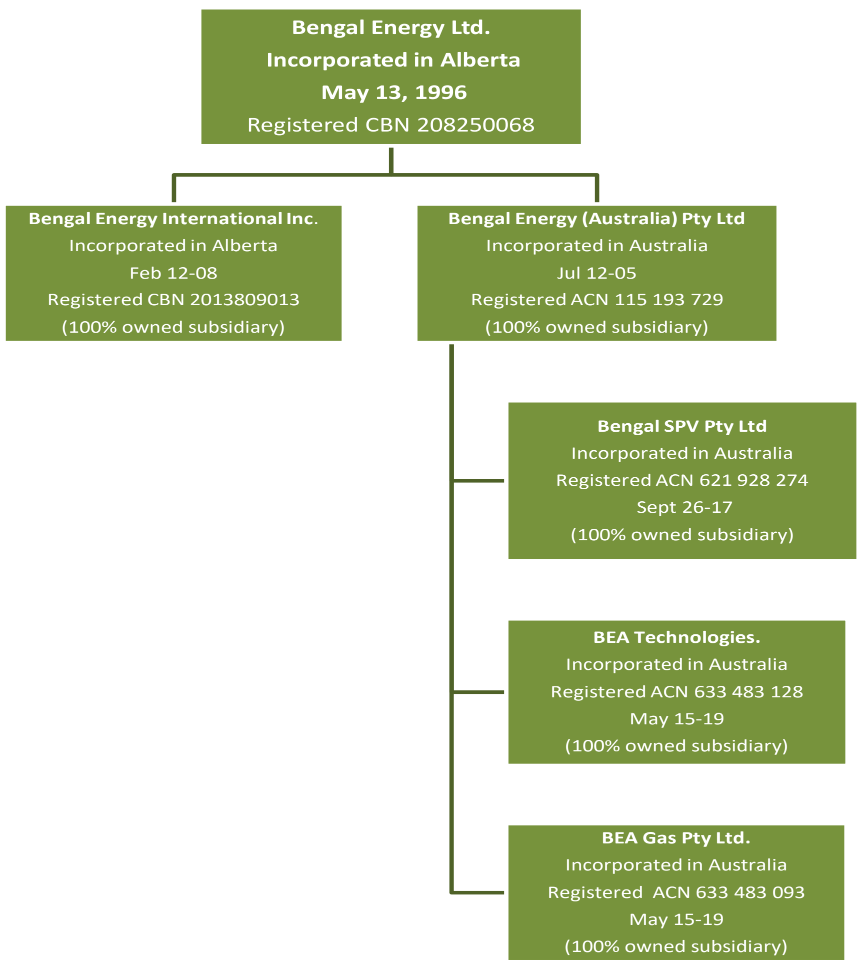
The Corporation was incorporated under the ABCA on May 13, 1996, as "694460 Alberta Inc." On June 18, 1996, the Corporation filed Articles of Amendment to change the Corporation's name to "Briggand Energy Corp.", and on October 8, 1996, to amend its share capital and to remove the private company restrictions 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 Suite 640, 630 – 6th Avenue S.W., Calgary, Alberta T2P 0S8.

The Common 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 natural 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 natural gas opportunities in Australia.

The Corporation has been active in developing a strategic growth plan through exploitation of its tenements at Wareena, Ghina, Ramses, and Karnak, as well as completion activity and further exploration based on the Nassarius 3D seismic program on PCA 332. In addition, the Corporation has work programs planned on its Barrolka East Permit natural gas assets.

Corporate Strategy

Bengal has producing and prospective light crude 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, subject to availability of financing through the issuance of equity, farm-outs of working interests and internally generated cash flows. 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. Subject to availability of financing, Bengal intends to grow its resource and reserves base within its existing acreage, most of which were acquired through bid rounds and farm-ins in Australia. Bengal also intends to continue building strategic alliances with appropriate local partners and large operators in Bengal's primary areas of focus. In addition, the Corporation is active in identifying and analyzing potential production acquisition opportunities within its core areas in onshore Australia and in other royalty friendly, resource rich jurisdictions. Expanding the regions in which to consider potential acquisitions is done with the intention to add size and financial capability to fund the Corporation's strong growth initiatives in Australia.

It is the intention of management of the Corporation to consider asset and corporate acquisition opportunities that meet Bengal's business parameters. While Bengal believes it has the management skills and resources necessary to achieve its stated objectives, participation in the exploration and development of oil and natural gas has a number of inherent risks. See "*Risk Factors*" herein.

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

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

(ii) risked return versus cost of capital;

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

(iv) oil and natural gas production levels;

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

(vi) the potential for additional reservoir development;

(vii) capital expenditure programs;

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

(ix) drilling plans;

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

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

(xii) the Corporation's ability to raise capital to fund an acquisition or drilling program, and to continually add to reserves through additional acquisitions, exploration and development;

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

(xiv) 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 an 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.

Competitive Conditions

Bengal is in the oil and natural gas industry, which is highly competitive and capital intensive, and many competitors have financial resources which exceed our own. Bengal competes with other companies for all of its business inputs, including development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. Our competitive position is similar to that of other oil and natural gas producers of a similar size and production profile. See "*Industry Conditions*" and "*Risk Factors*".

GENERAL DEVELOPMENT OF THE BUSINESS

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

Fiscal Year Ended March 31, 2022

General

On September 28, 2021, the Corporation appointed Peter Lansom as a director of the Corporation.

PL 303 and PL 1028, Barta Block, Cuisinier (controlling permit ATP 752) (30.357% WI)

In December 2021, the Chef exploration well was drilled on a structural feature identified on 3D seismic located northeast of the nearby Cuisinier field. No commercial accumulations of oil or natural gas were identified, and the well was plugged and abandoned. No other new drilling was performed on the Cuisinier field in the period ending March 31, 2022.

ATP 934 Barrolka East Permit

On April 24, 2020, the Corporation received regulatory approval for a special amendment to the initial work program on ATP 934, the Corporation's 100% owned natural gas exploration block. The Corporation had no further expenditure commitments on the permit before February 28, 2021, when the permit was up for renewal. As a condition of the approval of the special amendment, the Corporation agreed to relinquish an additional 17% of the permit in addition to the 33% mandatory relinquishment for a total of 50% (240 sub-blocks) of the acreage at the end of the first term on the permit. The acreage subject to the 50% relinquishment was determined by Bengal and consisted of the least prospective land from a technical perspective and with the most challenging access conditions under the terms of the existing environmental authority granted by the regulator. In return, the Corporation was granted a reduction in the total commitment from $12.3 million to $1.2 million which amount had previously been expended.

Effective March 1, 2021, ATP 934 was renewed for a period of six years over an area of 237 sub blocks (179,000 Gross acres). The LWP is comprised of geological and geophysical studies and the drilling of up to four wells or the drilling of up to three wells and the shooting of 260 square kilometres of 3D seismic. During the year ended March 31, 2021, ATP 934 was evaluated for any impairment triggers according to International Accounting Standards 36. As the Corporation was aware that a reduction in commitment level would be granted prior to the 2021 year end, no impairment triggers were identified. For the period ending March 31, 2022, additional technical work was carried out on ATP 934 in the form of the identification of key, 2D seismic lines for reprocessing and remapping of a series of previously identified prospects, which further confirmed the presence and location of such prospects.

Santos Farm-in – ATP 934 Barrolka East Permit

On July 24, 2020, Bengal's 100% owned Australian subsidiaries executed a Farm-in Agreement with Santos, whereby Santos committed to pay 100% of the cost of drilling a well on the farm-in lands to test the Permian section and either case and suspend or abandon the well to earn a 60% working interest in 137 sub-blocks (approximately 103,000 Gross (62,000 Net) acres). (the "**Durham Downs East Block**").

The Legbar 1 well (the "**Legbar 1 Well**") was drilled in calendar Q4 of 2021 at no cost to Bengal. However, insufficient levels of commercial hydrocarbon pay were encountered and the Legbar 1 Well was plugged and abandoned. The Legbar 1 Well qualified as a part of the LWP for the ATP 934 tenement.

Subsequent to the relinquishment, Bengal holds a 100% working interest in the Barrolka East Permit and a 40% working interest in the Durham Downs East Block which was farmed out to Santos on July 24, 2020.

PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)

On September 12, 2019, the Corporation entered into an agreement to acquire a 100% working interest in four PLs (being PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses and PL 411 Karnak) and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market. This transaction was completed in March of 2021.

As of March 31, 2022, the Corporation had plans to recomplete the Wareena 1 well (the "**Wareena 1 Well**") and the Wareena 5 well (the "**Wareena 5 Well**" and collectively the "**Wareena Wells**") and refurbish the pipeline and to subsequently perforate and flow test the Ramses 2 well (the "**Ramses 2 Well**") in the Poolowanna zone for oil production and longer-term gas production. The Corporation also planned for the Ghina well, being a cased well on the Ghina PL 1109, to be perforated and flow tested for gas and liquid production in the same program.

PCA 332 Tookoonooka (controlling permit ATP 732)

During the fourth fiscal quarter of 2022, the Corporation prepared for an acid stimulation program in the Caracal 1 well ("**Caracal 1 Well**") with the goal of enhancing the permeability and porosity of the oil-bearing Wyandra formation and to then be able to produce commercial volumes of light oil. Additionally, effective February 18, 2022, Bengal signed an offtake agreement with the neighbouring Inland Oil Refinery ("**IOR**") in Eromanga. The previously installed tank farm was staged and sized for an expansion in the event additional producing wells were brought on to production. Subject to starting production, the Caracal production area was earmarked for further development of additional oil prospects.

Private Placement Financing

On March 7, 2022, the Corporation closed a non-brokered private placement (the "**2022 Private Placement**"). Under the 2022 Private Placement, Bengal issued an aggregate of 52,317,821 Common Shares at a price of CDN$0.08 per Common Share for aggregate gross proceeds of approximately CDN$4.2 million. The net proceeds from the 2022 Private Placement, along with Bengal's internally generated cash flow, were used to fund Bengal's 100% owned and operated development program over 2 distinct blocks in Australia's onshore Cooper/Eromanga Basin, which program commenced in mid-2022.

Fiscal Year Ended March 31, 2023

PL 303 and PL 1028, Barta Block, Cuisinier (controlling permit ATP 752) (30.357% WI)

As of March 31, 2023, the Cuisinier field continued to produce and to follow a predictable decline profile. No new drilling was performed on the Cuisinier field in the period ending March 31, 2023.

The water injection scheme implemented in late 2021 operated on a temporary basis in the fiscal year ended March 31, 2023 due to surface equipment failures.

Barrolka East Permit (100% WI) and Durham Downs East Block (40% WI)(controlling permit ATP 934)

Bengal received approval of a special amendment for ATP 934 in March 2021 which relinquished 50% of the existing ATP 934 area and extended the term of ATP 934 by entering an outcome based LWP for another 6 years to February 28, 2027. As part of the special amendment, an additional relinquishment of 118 sub blocks (50% of the remaining sub blocks) (88,972 Gross acres) was required by February 28, 2023. The relinquished area was not considered to be prospective by the Corporation due to the lack of identified prospects and limited physical access. The LWP includes the drilling of up to three wells and the shooting of 260 square kilometres of 3D seismic.

PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)

A work program on both the Wareena 1 Well and the Wareena 5 Well, commenced in August 2022 with limited success in the Wareena 1 Well, but positive response evidenced by the wellhead pressure at the Wareena 5 Well when the Wareena 5 Well was shut in. Further dewatering work at both Wareena Wells is expected, subject to availability of equipment and personnel and availability of financing.

In September 2022 the water shut-off operations at its Wareena 1 and Wareena 5 sites were completed on time and on budget, with initial results that may support the Corporation's plans for further interventions designed to increase natural gas flow. Subject to the success of these interventions and positive test results, Bengal expects to evaluate its future capital and commercial plans to tie-in the wells to allow for commercial production and sale of natural gas from the wells.

At Wareena 1, the wellhead pressure was approximately 2,300 pounds/square inch, based on a measurement taken prior to the workover in 2021. However, there was considerable cross flow of water from the dominant lower watered out zone which resulted in diminished well performance. Post water shut-off, the fluid level increased while the Corporation monitored the well. This data supported the Corporation 's expectation that the reservoir should be capable of flowing commercial volumes of natural gas following the remediation of perforation damage resulting from more than eight years of inactivity. The Corporation intends to re-perforate all of the PC-20 sand and swab and test the well. These operations are expected to occur as soon as equipment and contractors are available.

At Wareena 5, the Corporation has been monitoring the well post water shut-off and the data indicates that the PC20 sand was likely impaired during the well's shut-in period of more than eight years. The Corporation has the option to re-perforate all of the PC-20 sand and swab and test the well in concert with its operations at Wareena 1.

PCA 332 Tookoonooka (controlling permit ATP 732)

During the fiscal year of 2023, the Corporation conducted a preliminary workover and stimulation program at the Caracal 1 Well. The Caracal 1 Well produced oil to surface, although at lower-than-expected rates. The Caracal 1 Well was assessed to determine capacity for commercial production versus drilling a more optimally placed appraisal well to assess the extent of the structure.

ATP 732 reached the end of its term in March of 2023 and the Corporation lodged an application over the northern portion of the ATP for continuation in the form of PCA 332 for a further 15 years.

In advance of ATP 732 reaching the end of its term in March 2023, the Corporation lodged an application in August 2022 over the northern portion of ATP 732 for the continuation in the form of PCA 332 for a further 15 years. Based on the positive results from Caracal 1 Well, the application was approved on January 30, 2023. In addition, the Corporation continued to assess farm-in interest on other 3D defined drilling targets on PCA 332.

The Corporation reported the deployment of its Early Oil Production System at the Caracal 1 production area in Australia's Cooper Basin. The successful commissioning of the Early Oil Production System– a mobile Lufkin "Road Runner" Pumping Unit – allows for oil production from Bengal's wells as well as being able to offer pumping services to third parties. Further evaluation will be required to assess the commercial viability of the Caracal 1 well for long term oil production.

Fiscal Year Ended March 31, 2024

General

On September 21, 2023, James Howe resigned as a director of the Corporation.

On January 18, 2024, the Corporation appointed Barry Herring, an accomplished finance executive, as a director of the Corporation and Chair of the Audit Committee of the Corporation's board of directors.

PL 303 and PL 1028, Barta Block, Cuisinier (controlling permit ATP 752) (30.357% WI)

During the fiscal year ended March 31, 2024, the Corporation continued to evaluate the results of its water injection program at the Cuisinier field. The injection of produced formation water resulted in both increased production in up to four offsetting wells and reduced water handling charges during periods in which the water injection program has been operational. On establishing success of the program, Bengal's anticipates that the JV will begin a multi-staged water injection scheme, targeted fracture stimulation and more commercially efficient development drilling. Whilst the JV has observed compelling evidence that the overall Cuisinier field decline has been temporarily arrested with a modest upward trend in oil production rate during the previous quarters, the program has suffered from extended shut-in periods due primarily to surface equipment failure and is waiting on replacement parts. The program was intermittently operational during fiscal 2024.

Bengal's JV partner and operator of the Cuisinier pool drilled four wells in the Cuisinier field during calendar 2023. The Corporation did not participate in this drilling program based on its internal technical assessment of well locations. Additionally, the Cuisinier operator's projected capital and operating costs made such investment less attractive to Bengal than alternatives available in Bengal's inventory.

PCA 332 Tookoonooka** (**controlling permit ATP 732) (100% WI)

PCA 332, in which Bengal has a 100% working interest, covers an 84,827 Gross acre prospect area and was granted for a 15-year term effective January 30, 2023.

Work during 2024 identified up to 15 independent multi-horizon prospects located in PCA 332, including the Corporation's Tigris-1 oil opportunity ("**Tigris-1**"). The Corporation believes that drilling success at Tigris-1 would allow Bengal to pursue a follow-up multi-well development program, as well as support the appraisal of other opportunities on PCA 332.

The Corporation has identified analogous discoveries located in the Tintaburra and Toobunyah fields approximately 25 km east of PCA 332 having production rates between 1,000 and 1,500 Bbls/d from the Hutton zones and 200 to 500 Bbls/d from the Wyandra zones.

The Corporation believes that the fully paid for and installed oil sales infrastructure in PCA 332 allows for ready egress by trucking in the event of successful drilling through established sales and the transportation agreement with IOR located within 62 km of PCA 332 by way of a hard-sealed road.

The exploration and development of any of the prospects identified, including Tigris-1, is subject to the Corporation securing adequate financing on terms acceptable to the Corporation. To date such financing has not been secured; however, the Corporation is actively seeking potential farm-in partnerships with third-party industry participants and other financing arrangements.

PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)

During the year, Bengal worked to integrate subsurface data from the PLs to try and enhance the Corporation's understanding of these PLs and to finalize the selection of future exploration and appraisal drilling locations. No further field work was done on PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses or PL 411 Karnak during the fiscal year ended March 31, 2024.

In late 2023, new legislation was enacted for Queensland affecting oil and gas exploration or development activity over a portion of the Lake Eyre Basin where PL 411 Karnak and PL 188 Ramses are located. Under the new legislation, restrictions will be applied to future fracking operations for PL 411 Karnak and PL188 Ramses with lands designated as PL's being exempt from the total ban on activity.

Barrolka East Permit (100% WI) and Durham Downs East Block (40% WI)(controlling permit ATP 934)

A relinquishment of 118 sub blocks (50% of the existing 237 sub blocks) (88,972 Gross acres) in ATP 934 was completed and accepted by the regulator during April of 2023. Subsequent to the relinquishment Bengal holds a 100% working interest in the Barrolka East Permit and a 40% working interest in the Durham Downs East Block.

In late 2023, new legislation was enacted for Queensland which effectively bans any oil and gas exploration or development activity over a portion of the Lake Eyre Basin in which the Durham Downs East Block is located. Santos, the operator of this Durham Downs East Block, is currently formulating a response to the Queensland regulator relating to their impacted portfolio which includes this property.

Recent Developments

AC/RL 10 Katandra

Bengal entered into a binding term sheet agreement with an undisclosed party which grants an option to acquire an 80% working interest in the AC/RL 10 Katandra prospect in exchange for assignment of operatorship and carrying out of all administrative support activities and possible further financing arrangements on the permit until such time as the applied for five-year extension of the permit has been approved by the regulatory authority and the option has been exercised by the holder.

Significant Acquisitions

The Corporation did not complete any acquisitions during the most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

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**") is dated March 31, 2024. The Statement has an effective date of March 31, 2024, and a preparation date of June 5, 2024.

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, 2024. The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. GLJ is an independent reserves evaluator pursuant to NI 51-101 and the COGE Handbook. The Reserves Data summarizes the 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* in Form 51-101F3 and *the Report on Reserves Data by the Independent Qualified Reserves Evaluator* in Form 51-101F2 are attached as Schedules "A" and "B" hereto, respectively.

All of the Corporation's reserves are located in Australia.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead, and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. The recovery and reserve estimates of the Corporation's oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil 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, 2024
FORECAST PRICES AND COSTS

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		**HEAVY CRUDE OIL**		**CONVENTIONAL NATURAL GAS**		**NATURAL GAS LIQUIDS**		**TOTAL**	
RESERVES CATEGORY:	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MBOE)**	**Net (MBOE)**
PROVED	268	246	-	-	-	-	-	-	268	246
Developed Producing	247	227	-	-	-	-	-	-	247	227
Developed Non-Producing	21	19	-	-	-	-	-	-	21	19
Undeveloped	604	554	-	-	-	-	-	-	604	554
TOTAL PROVED	872	800	-	-	-	-	-	-	872	800
PROBABLE	985	901	-	-	-	`	-	-	985	901
TOTAL PROVED PLUS PROBABLE	1,857	1,701	-	-	-	-	-	-	1,857	1,701

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.

NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF MARCH 31, 2024
FORECAST PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					**AFTER INCOME TAXES DISCOUNTED AT (%/year)**					**Unit Value Before Income Taxes**	
											Discounted at 10%/year	**Discounted at 10%/year**
($M)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**($/BOE)**	**($Mcfe)**
PROVED												
Developed Producing	7,090	6,948	6,625	6,256	5,895	7,090	6,948	6,625	6,256	5,895	29.23	4.87
Developed Non-Producing	934	762	630	528	447	934	762	630	528	447	32.95	5.49
Undeveloped	20,410	15,130	11,353	8,662	6,721	20,410	15,130	11,353	8,662	6,721	20.50	3.42
TOTAL PROVED	28,434	22,840	18,609	15,447	13,064	28,434	22,840	18,609	15,447	13,064	23.27	3.88
PROBABLE	48,390	32,973	23,449	17,397	13,394	37,961	26,911	19,769	15,082	11,893	26.03	4.34
TOTAL PROVED PLUS PROBABLE	76,824	55,813	42,058	32,844	26,458	66,395	49,750	38,378	30,529	24,957	24.73	4.12

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.
(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, 2024
FORECAST PRICES AND COSTS

RESERVES CATEGORY:	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs[(1)]	Future Net Revenue Before Future Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
($M)								
TOTAL PROVED RESERVES	100,563	8,335	49,193	11,608	2,993	28,434	0	28,434
TOTAL PROVED PLUS PROBABLE RESERVES	223,178	18,887	103,475	19,853	4,140	76,824	10,429	66,395

Notes:

(1) 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*".
(2) The numbers in this table may not add exactly due to rounding.

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF MARCH 31, 2024
FORECAST PRICES AND COSTS
(Before income taxes and discounted at 10% per year)

RESERVE CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE FUTURE INCOME TAXES ($M)	UNIT VALUE BEFORE INCOME TAX ($/BOE)	UNIT VALUE BEFORE INCOME TAX ($/Mcfe)
Proved	Light Crude Oil and Medium Crude Oil (Including solution gas and associated by-products)	18,609	23.27	3.88
	Heavy Crude Oil (Including solution gas and associated by-products)	-	-	-
	Nature Gas Liquids (Including propane, butane, field condensate as well as condensate recovered at natural gas processing facilities)	-	-	-
	Conventional Natural Gas (Including associated by-products but excluding solution gas and by-products from oil wells)	-	-	-
TOTAL PROVED		18,609	23.26	3.88
Proved Plus Probable	Light Crude Oil and Medium Crude Oil (Including solution gas and associated by-products)	42,058	24.73	4.12
	Heavy Crude Oil (Including solution gas and associated by-products)	-	-	-
	Nature Gas Liquids	- 0	-	-

(Including propane, butane, field condensate as well as condensate recovered at natural gas processing facilities)			
Conventional Natural Gas (Including associated by-products but excluding solution gas and by-products from oil wells)	-	-	-
TOTAL PROVED PLUS PROBABLE	42,058	24.73	4.12

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 Bengal revenue and costs not related to a specific product type have been allocated proportionately to the specified product types.

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, forecast prices and costs, in Canada 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 reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which 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, 2024. GLJ has only assigned light crude oil reserves in the GLJ Report with pricing based on Brent plus a 1% premium.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (AUSTRALIAN PROPERTIES AS OF MARCH 31, 2024)

YEAR FORECAST	**Inflation[(2)] Rate (%)**	**Brent ($Cdn/Bbl)**	**Exchange Rate[(3)] ($Cdn /$ US)**	**Brent[(4)] ($US/Bbl)**
2024 Q2-Q4[(1)]	0	**111.18**	0.745	82.83
2025	2.0	107.95	0.755	81.50
2026	2.0	106.54	0.765	81.50
2027	2.0	107.95	0.765	82.58
2028	2.0	110.05	0.765	84.19
2029	2.0	112.29	0.765	85.90
2030	2.0	114.56	0.765	87.64
2031	2.0	116.82	0.765	89.37
2032	2.0	119.16	0.765	91.16
2033	2.0	121.54	0.765	92.98
2034+	2.0	+2%/yr	0.765	+2%/yr

Notes:

(1) 2024 forecast pricing is for the last nine months (April 1 - December 31) of 2024.
(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.

Weighted average historical prices realized by the Corporation for the year ended March 31, 2024 were US$82.93 (CDN$112.29) Bbl for light crude oil and medium crude oil. All of the Corporation's oil sales in Australia are based upon Brent oil pricing in US dollars plus a 1% oil quality premium.

The following table sets forth the actual pricing and exchange rate used in the GLJ Report:

YEAR FORECAST	Brent x 1.01 ($Cdn/Bbl)	Exchange Rate[3] ($Cdn/$ US)	Brent[4] ($US/Bbl)
2024 Q2-Q4[1]	112.34	0.745	82.83
2025	109.03	0.755	81.50
2026	107.60	0.765	81.50
2027	109.03	0.765	82.58
2028	111.15	0.765	84.19
2029	113.41	0.765	85.90
2030	115.71	0.765	87.64
2031	117.99	0.765	89.37
2032	120.35	0.765	91.16
2033	122.76	0.765	92.98
2034+	125.21	0.765	+2%/yr

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

7. Well abandonment and reclamation costs for wells with assigned reserves 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.

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

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[5]

	Light Crude Oil and Medium Crude Oil			Total BOE		
FACTORS	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved plus Probable (Mbbl)**	**Gross Proved (MBOE)**	**Gross Probable (MBOE)**	**Gross Proved Plus Probable (MBOE)**
March 31, 2023	2,005	3,472	5,477	2,005	3,472	5,477
Extensions[1]	-	-	-	-	-	-
Improved Recovery[1]	-	-	-	-	-	-
Infill Drilling[1]	-	-	-	-	-	-
Technical Revisions[2]	(1,071)	(2,487)	(3,558)	(1,071)	(2,487)	(3,558)
Discoveries	-	-	-	-	-	-
Acquisitions[3]	-	-	-	-	-	-
Dispositions[3]	-	-	-	-	-	-
Economic Factors[4]	-	-	-	-	-	-
Production	(62)	-	(62)	(62)		(62)
March 31, 2024	872	985	1,857	872	985	1,857

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 would be combined and reported as Extensions and Improved recovery.

(2) Includes technical revisions due to reservoir performance, geological and engineering changes and reclassification of proved and probable undeveloped reserves as contingent resources. The negative technical revisions resulted from the reclassification of volumes of proved undeveloped reserves to contingent resources, in compliance with regulatory requirements defining the timing of development required to continue to carry these volumes as reserves.

(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.

(5) No heavy crude oil, natural gas liquids or conventional natural gas reserves were assigned as at March 31, 2022 or March 31, 2023 so there are no reconciliations to provide in respect of any such reserves.

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.

(a) 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:

Year	**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**
2022	-	1,824	-	-	-	-	-	-	-	1,824
2023	-	1,701	-	-	-	-	-	-	-	1,701
2024[1]	-	604[2]	-	-	-	-	-	-	-	604[2]

Notes:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date March 31, 2024.

(2) The decrease in the volume of light crude oil in 2024 total at year end is due to the reclassification of volumes of proved undeveloped reserves to contingent resources.

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 relate to planned infill drilling locations. The majority of the proved undeveloped locations are available for scheduling to be on production within a five-year time frame. The development of certain proven undeveloped reserves has been deferred to accommodate the Corporation's development program, which needs to be spread out over several years to optimize capital allocation and facility utilization.

For the Cuisinier property, proved reserves were recognized for drilling locations within one drill spacing unit ("**DSU**") from existing proven production or DSUs that have had successful tests carried out and that are within the existing production license area. These locations have been recognized by the Corporation as part of the development of the field. However, development pace is controlled by the Cuisinier operator. The Cuisinier operator has provided the Corporation with their field development program for Cuisinier which states four to five wells will be drilled every second year. Proved undeveloped reserves were recognized for twelve drilling locations which drilling locations have been scheduled over five years from the effective date of the development program. Proved plus probable undeveloped reserves were recognized for eight drilling locations which are located within two DSUs from existing wells and which drilling locations have been scheduled over seven years from the effective date of the development program.

The Corporation has a development program planned for the Cuisinier field for a portion of the proved undeveloped reserves in 2025 through the drilling of four proved undeveloped wells in 2025, followed by similar programs in 2027 and 2029. Probable undeveloped reserves location drilling plans set forth the drilling of one well in each of 2025, 2027 and 2029, with five wells planned to be drilled in 2031, focusing on the development drilling opportunities in the Cuisinier field in Australia, and subject to financing for such drilling being available to the Corporation.

The Cuisinier field and production infrastructure are in a remote area of the Cooper Basin. Timing of drilling campaigns require JV alignment and program approvals, drilling contractor and drilling rig availability and surface conditions allowing access. The operator of the Cuisinier asset has the responsibility of arranging these campaigns and has advised on the timing of the preceding drilling schedule. The Corporation is fully committed to future drilling activities at the Cuisinier field and recognizes the accretive upside to further development. However, any future activity will be influenced by the results of the Cuisinier water-injection program, as well as equity or debt financing being available to the Corporation on acceptable terms. The remaining future development capital is subject to both internal approval and availability of capital to the Corporation.

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, facility utilization and drilling rig availability in the remote part of Australia where the Corporation has oil development opportunities. Surface access issues associated with landowners, weather conditions or regulatory approvals could also influence development plans.

As of March 31, 2024, Bengal's proved undeveloped reserves represented 69% of Bengal's total proved reserves, with proved plus probable undeveloped reserves representing 81% of its proved plus probable reserves. Volatile commodity prices and lack of joint-venture partner alignment has delayed planned drilling programs, which will be responsive to commodity price environments in the future. Through an ongoing planned drilling program in Australia over the next five years, it is anticipated that a portion of the proved undeveloped reserves will be converted to proved developed, and the majority of probable undeveloped to proved.

(b) 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:

Year	**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**
2022	-	3,524	-	-	-	-	-	-	-	3,524
2023	-	3,373	-	-	-	-	-	-	-	3,373
2024[1]	-	893[2]	-	-	-	-	-	-	-	893[2]

Note:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date March 31, 2024.

(2) The decrease in the volume of light crude oil in 2024 total at year end is due to the reclassification of volumes of probable undeveloped reserves to contingent resources.

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. The development of certain probable undeveloped reserves is scheduled to occur after the end of year two to accommodate the Corporation's development program, which needs to be spread out over several years to optimize capital allocation and facility utilization. The Corporation has planned a program for the development of a portion of the undeveloped reserves in 2025, focusing on the development and appraisal opportunities available in the Cuisinier field in Australia. The probable undeveloped location drilling plan has one well being drilled in 2025, one well being drilled in 2027, one well being drilled in 2029 and five wells being drilled in 2031.

The Cuisinier field and production infrastructure are in a remote area of the Cooper Basin. Timing of drilling campaigns require JV alignment and program approvals, drilling contractor and drilling rig availability and surface conditions allowing access. The operator of the Cuisinier asset has the responsibility of arranging these campaigns and has advised on the timing of the preceding drilling schedule. The Corporation is fully committed to future drilling activities at the Cuisinier field and recognizes the accretive upside to further development. However, any future activity will be influenced by the results of the Cuisinier water-injection program, as well as equity or debt financing being available to the Corporation on acceptable terms. The remaining future development capital is subject to both internal approval and availability of capital.

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, facility utilization and drilling rig availability in the remote part of Australia where the Corporation has oil development opportunities. Surface access issues associated with landowners, weather conditions or regulatory approvals could also influence development plans. The GLJ Report indicates that Bengal has 893 Mbbls 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.

(c) Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves 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 natural 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 significant 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, 2024, as well as the "*Risk Factors*" and "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" sections herein.

The Corporation does not anticipate any unusually high abandonment or reclamation costs. The GLJ Report includes provisions for the abandonment and reclamation of all of the Corporation's existing and future wells, to which reserves or resources have been included within its evaluation, to a standard imposed by applicable government or regulatory authorities. All abandonment and reclamation costs for existing wells without reserves have not been included. Additional information related to the Corporation's 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, 2024 and the accompanying management's discussion and analysis, which are available on SEDAR+ at www.sedarplus.ca.

(d) 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:

($M)	**FORECAST PRICES AND COSTS**	
Year	**Proved**	**Proved Plus Probable**
2024	-	-
2025	3,743	4,785
2026	217	217
2027	3,748	4,905
2028	-	-
2029	3,899	4,874
2030	-	-
2031	-	5,071
2032	-	-
2033	-	-
2034	-	-
Thereafter	-	-
Total Undiscounted	11,608	19,853
Total Discounted @ 10%	8,706	13,637

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 $11,608 million will be sufficient to fund the future development costs of its proved reserves disclosed above and $19,853 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. In the future the Corporation may consider alternative sources of financing in light of new or changing circumstances. The funding of such future development costs will be subject to the operator's demonstration of accretive drilling locations as part of a field development plan accounting for the impacts of the water injection program.

Estimates of reserves and future net revenues have been made assuming that each property in respect of which the estimate is made will be developed, without regard to the likely availability to the Corporation of funding required therefor. There can be no guarantee that such funds will be available or that the Corporation will allocate funding to develop all the reserves attributed in the GLJ Report. Failure to develop those reserves could have a negative impact on future cash flows from operations.

Other Oil and Gas Information

Principal Properties

The following is a description of the Corporation's principal oil and natural gas properties as at March 31, 2024, 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, 2024, based on operator statements. The reserve amounts stated are Gross reserves, as at March 31, 2024, based on forecast costs and prices as evaluated in the GLJ Report (see "*Statement of Reserves Data and Other Oil and Gas Information*"). 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.

The Corporation is engaged in the exploration for, and development and production of, crude oil and natural gas in the Cooper/Eromanga Basin in Australia all of which is onshore. Bengal has a large acreage position across the onshore Cooper/Eromanga Basin of Australia of over 360,000 Gross acres. Bengal's Cooper/Eromanga acreage is split among three principal separate blocks of land that are covered by: PL 303 and PL 1028 (controlling permit ATP 752), PCA 332 Tookoonooka (controlling permit ATP 732), and Barrolka East Permit and Durham Downs East Block (controlling permit ATP 934) as well as its PLs, being PL 114 (now PL 1110) Wareena, PL 157 (now PL 1109) Ghina, PL 188 Ramses, and PL 411 Karnak. In addition, the Corporation holds a 100% working interest in AC/RL 10 located in the Ashmore Cartier area of the Timor Sea, north of Australia comprised of approximately 168 km^2 (41,514 acres).

Onshore Australia:

PL 303 and PL 1028 – (controlling permit ATP 752, Barta and Wompi sub-blocks, Queensland, Australia)

Bengal has multiple interests in ATP 752. ATP 752 is in 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).

The Barta sub-block comprises approximately 94,147 Gross acres (28,583 Net acres) as well as the 15,815 Gross acre (4,801 Net acres) PL 303, and approximately 2,965 Gross acres (900 Net acres) on PL 1028 while the Wompi sub-block including PCA 155 Nubba/Yilgarn, comprises a total of 22,487 Gross acres (8,563 Net acres). The land is subject to a sliding scale royalty payable on production to the Queensland Government, along with a 1% royalty reserved to the native title owners on a portion of the southeast part of PL 1028.

The ATP 752 properties include 20 Gross (6.1 Net) producing light crude oil wells and 11 Gross (4.7 Net non-producing light crude oil wells. Average daily production from the properties for the year ended March 31, 2024, was 172 BOE/d and was weighted 100% to light crude oil. As at March 31, 2024, the GLJ Report attributed proved plus probable Corporation Gross reserves of 1,857 Mbbls of light crude oil and no NGLs or natural gas reserves to the ATP 752 properties.

On the Wompi sub-block on March 31, 2017, Bengal was granted PCA 155 Nubba/Yilgarn. On March 28, 2022, Bengal Australia issued a Sole Risk Notice to re-enter and test the Nubba-1 well to the other two ATP 752 JV parties with a working interest in the tenement. Due to weather constraints, the Sole Risk Notice lapsed after 180 days and has not been re-issued.

On July 31, 2018, 287,967 Gross acres (87,398 Net acres) of ATP 752 were relinquished. On March 14, 2019, Bengal received notice from the Queensland Government of the grant of two PCAs (PCA 206 and PCA 207) that Bengal and its JV partners had applied for in January 2018. These PCAs allow a further 10 years to assess commerciality on the 133 Gross (40.5 net) sub-blocks granted which cover the remaining prospective lands lying to the west and north of the Cuisinier field (PL303), in the ATP 752 Barta Block. The PLs continue through the life of any reserves discovered on such PLs prior to expiry. The PCAs cover the remnant lands within ATP 752 that were selected as having the highest probability of achieving commerciality within the next 10 years and replace of the bulk of the ATP 752 relinquished lands.

For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2022*", "*General Development of the Business – Fiscal Year Ended March 31, 2023*", "*General Development of the Business – Fiscal Year Ended March 31, 2024*" *and* "*Exploration and Development Activities*".

Oil and Natural 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, 2024. As at March 31, 2024, the Corporation had an interest in 38 Gross (17.1 Net) oil and natural gas wells as follows, all such wells are onshore wells in Queensland Australia.

	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	**20**	**6.1**	**-**	**-**	**11**	**4.7**	**7**	**6.3**	**31**	**10.8**	**7**	**6.3**	**38**	**17.1**

Notes:

(1) This table does not include dry wells or abandoned wells.
(2) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Of the non-producing wells, that the Corporation held a working interest in during the fiscal year ended March 31, 2024, 1 Gross (0.3 Net) well was capable of production and had reserves assigned to it. Such well had a mechanical failure in February 2024 and is expected to resume production in the second half of 2024.

Properties with No Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at March 31, 2024:

	DEVELOPED ACRES		**UNDEVELOPED ACRES[2]**		**TOTAL ACRES**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Australia[1]	15,937	4,838	401,920	285,429	417,857	290,267
Total	15,937	4,838	401,920	285,429	417,857	290,267

Notes**:**

(1) Undeveloped acreage includes PL 1028, PCA 206 and PCA 207 under controlling permit ATP 752 Barta sub-block as well as PCA 155 Nubba/Yilgarn under controlling permit ATP 752 Wompi sub-block, ATP 732, ATP 934, including PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak and AC/RL 10.
(2) Of these undeveloped land holdings, zero Net acres could expire by March 31, 2025 if not developed/extended.
(3) Bengal calculates both its Gross and Net acres on a per lease basis.

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, 2022*", "*General Development of The Business – Fiscal Year Ended March 31, 2023*" and "*General Development of The Business – Fiscal Year Ended March 31, 2024*" above and "*Exploration and Development Activities*", below.

***Onshore Australia*:**

PCA 332 Tookoonooka (controlling permit ATP 732, Queensland, Australia)

ATP 732 was 207,816 Net acres in size (275 sub blocks) subsequent to mandatory relinquishment and was tested by only eight exploration wells prior to relinquishment. ATP 732 was surrounded by existing Permian gas fields and Jurassic and Cretaceous oilfields. The center of ATP 732 was the site of what is believed to have been an ancient (Cretaceous) meteor impact structure. Following the second relinquishment in March of 2019 the carrying value of ATP 732 was written down accordingly to $5.38 million for the year ended March 31, 2020. ATP 732 reached the end of its term on March 31, 2023, and has been partially replaced by PCA 332, which is 84,827 Gross/Net acres (112 sub blocks). Bengal has a 100% WI in PCA 332. The remainder of the blocks were relinquished (163 sub blocks) in March of 2023.

PCA 332 covers a 343 km^2 prospect area and was granted for a 15-year term effective January 30, 2023. PCA 332 includes no producing wells as at March 31, 2024, and the GLJ Report therefore attributes no reserves to the ATP 732 property.

Bengal is the operator of PCA 332 with a working interest of 100%. The land is subject to a sliding scale 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, 2022*", "*General Development of the Business – Fiscal Year Ended March 31, 2023*", "*General Development of the Business – Fiscal Year Ended March 31, 2024*" *and* "*Exploration and Development Activities*".

Barrolka East Permit and Durham Downs East Block, (controlling permit ATP 934, Queensland, Australia)

Bengal received approval of a special amendment for ATP 934 in March 2021 which relinquished 50% of the existing ATP 934 area and extended the term of ATP 934 by entering an outcome based LWP for another 6 years to February 28, 2027. As part of the special amendment, another relinquishment of 118 sub blocks (50% of the remaining sub blocks) (88,972 Gross acres) was required by February 28, 2023. This relinquishment was made and accepted by the regulator during April of 2023. The relinquished area was not considered to be prospective by the Corporation due to the lack of identified prospects and limited physical access. The LWP includes the drilling of up to 3 wells and the shooting of 260 km^2 of 3D seismic.

Bengal currently holds a 100% working interest in the 31,768 acre Barrolka East Permit and a 40% working interest in the 58,242 Gross acres (23,297 Net acres) acre Durham Downs East Block which was farmed out to Santos on July 24, 2020. Both blocks are in the heart of the Cooper/Eromanga Basin and are surrounded by known liquids rich gas fields. ATP 934 flanks the east margin of the large Barrolka gas field. Recent activity west and south of ATP 934 has resulted in new natural gas discoveries. In 2017 and 2018, seismic re-interpretation involving an AVO/Inversion workflow resulted in a high grading of more prospective reservoir sand trends on the permit.

In late 2023, new legislation was enacted for Queensland which effectively bans any oil and gas exploration or development activity over a portion of the Lake Eyre Basin in which the Durham Downs East Block is located. Santos, the operator of this Durham Downs East Block, is currently formulating a response to the Queensland regulator relating to their impacted portfolio which includes this property.

The ATP 934 property includes no producing oil wells or producing natural gas wells as at March 31, 2024, and the GLJ Report therefore attributes no reserves to the ATP 934 property.

The land is subject to a sliding scale 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.

For additional details, see "*General Development of the Business – Recent Developments – Fiscal Year Ended March 31, 2022*", "*General Development of the Business – Fiscal Year Ended March 31, 2023*", "*General Development of* *the Business – Fiscal Year Ended March 31, 2024*" and "*Exploration and Development Activities*".

PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline, Queensland, Australia

Bengal currently holds a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia natural gas market. The four PLs (being PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses and PL 411 Karnak) total 65,977 Net acres (87 sub-blocks). These non-producing PLs are close to ATP 934 and surrounding infrastructure.

Included on the Ramses PL 188 is the Ramses 2 Well which contains an opportunity for an oil-zone completion in the Poolowanna Formation. This opportunity is based on the extrapolation of the recovery of 49 barrels of light crude oil on a two-hour drill stem test which indicated an estimated daily flow rate of 588 Bbls/d, when it was drilled in 2007. Initial oil analysis indicated a high viscosity, which can be problematic in the design of a completion program. Upon completion of a successful test, this well is expected to be immediately equipped for production and the oil sold into the regional market. In addition, the Wareena PL 1110 holds the Wareena Wells, which in combination produced 6.4 billion cubic feet of natural gas before being suspended due to water inflow based on production results obtained from the prior operator. The Corporation believes one or both of the Wareena Wells can be brought back into production with careful detail paid to draw down pressures and downstream compression. The 100% ownership of PL 1110 Wareena, PL 1109 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline presents an appraisal and development opportunity that will be operated by the Corporation and is seen to be not only complementary to our proven producing, non-operated Cuisinier asset, but also as a key steppingstone for Bengal's natural gas platform with immediate market access through an existing pipeline around which future exploration growth through ATP 934 could be undertaken.

The PLs referenced above include no producing oil wells or producing natural gas wells as at March 31, 2024, and the GLJ Report therefore attributes no reserves to these properties.

For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2022*", "*General Development of the Business – Fiscal Year Ended March 31, 2023*" and "*General Development of the Business – Fiscal Year Ended March 31, 2024*".

Offshore Australia:

AC/RL 10 (formerly AC/P24) Ashmore Cartier Area, Timor Sea, Offshore Australia

In addition to its Cooper/Eromanga properties, the Corporation also holds a 100% working interest in AC/RL 10 located in the Ashmore Cartier area of the Timor Sea, north of Australia comprised of approximately 168 km^2 (41,514 Net acres).

During 2020 and 2021, Bengal participated in a reprocessing project on the two 3D seismic surveys over AC/RL 10 lands, which was completed in May 2020. Seismic interpretation was completed in early 2021.

AC/RL 10 includes no producing wells as at March 31, 2024, and the GLJ Report, therefore, attributes no reserves to the AC/RL 10 property.

The Katandra – 1A discovery well was drilled in December 2004 and encountered a 5.3 metre column of light oil at the top of the Upper Vulcan formation. The well was plugged and abandoned and ongoing work to better visualize both the Katandra structure and the much larger Katandra North Prospect is ongoing. The Katandra JV had reprocessed the original Onnia 3D survey and the later Schwarzer 3D to estimate ultimate prospect sizes. The permit has stayed in good standing and is classified as a Retention Lease. The permit reached the end of its term on March 21, 2023, but could be renewed for a further 5 years to March 21, 2028.

The operator, PTTEP Australasia (Ashmore Cartier) Pty Ltd elected not to continue with the permit and, pursuant to the joint operating agreement between the parties, assigned its 90% interest to Bengal effective March 21, 2023, leaving Bengal with 100% working interest in the permit. On January 18, 2023, Bengal lodged a Title Transfer Application with the National Offshore Petroleum Titles Administrator ("**NOPTA**") which was approved effective February 23, 2023. Bengal subsequently lodged a Renewal Application for a further five years which is currently under negotiation with NOPTA (the regulator).

Bengal entered into a binding term sheet agreement with an undisclosed party which grants an option to acquire an 80% working interest in the AC/RL 10 Katandra prospect in exchange for assignment of operatorship and carrying out of all administrative support activities and possible further financing arrangements on the permit until such time as the applied for five-year extension of the permit has been approved by the regulatory authority and the option has been exercised by the holder.

Significant Factors or Uncertainties Relevant to Properties with No Attributable Reserves

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

Forward Contracts

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 during prior years 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.

As at March 31, 2024, the Corporation has no outstanding financial commodity contracts.

Tax Horizon

The Corporation does not expect to pay current income tax for taxation periods associated with its 2024 fiscal year. Depending on the production, commodity prices, and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2040 or beyond.

Costs Incurred

The following table summarizes costs incurred related to the Corporation's activities for the year ended March 31, 2024:

EXPENDITURES	Canada (M$)	Australia (M$)	Total (M$)
Property Acquisition costs – Proven Properties	-	-	-
Property Acquisition costs – Unproven Properties	-	-	-
Exploration:	-	-	-
Geological and Geophysical	-	77	77
Drilling	-	-	-
Completions/Facilities	-	-	-
Acquisitions	-	-	-
Exploration Subtotal	-	77	77
Development:	-	-	-
Geological and Geophysical	-	-	-
Drilling	-	-	-
Completions/Facilities	-	397	397
Acquisitions	-	-	-
Development Subtotal	-	397	397
TOTAL	-	474	474

Note:

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

Exploration and Development Activities

No exploration or development wells were completed in the Corporation's most recent financial year. See "*General Development of the Business – Fiscal Year Ended March 31, 2024*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*" and below for details regarding the Corporation's drilling program and its properties, all of which are in Australia.

PL 303, Barta Block Cuisinier (controlling permit ATP 752, Barta Block), Queensland, Australia

In the fiscal year ended March 31, 2024, the Corporation did not drill any wells. Production rates followed forecast declines through the year. Work continued on the implementation of the water injection/reservoir pressure maintenance project.

Oil prices which had been adversely affected by geopolitical events and pandemics have recovered and current and forecast oil pricing now allows for the resumption of pool development through additional drilling expected in 2025. See "*General Development of the Business – Fiscal Year Ended March 31, 2022*", "*General Development of the Business – Fiscal Year Ended March 31, 2023*", "*General Development of the Business – Fiscal Year Ended March 31, 2024*" and "*Statement of Reserves Data – Other Oil and Gas Information – Principal Properties*".

PCA 332 Tookoonooka (controlling permit ATP 732)

In advance of ATP 732 reaching the end of its term in March 2023, the Corporation lodged an application in August 2022 over the northern portion of ATP 732 for the continuation in the form of PCA 332 for a further 15 years. Based on the positive results from Caracal 1 Well, the application was approved on January 30, 2023. In addition, the Corporation continued to assess farm-in interest on other 3D defined drilling targets on PCA 332. The Corporation believes that PCA 332 provides certainty for Bengal to focus on its hydrocarbon projects in the Tintaburra and Toobunyah corridor of PCA 332. The majority of PCA 332 is covered by 3D seismic which has outlined the prospective targets as previously announced by the Company.

Work during 2024 identified up to 15 independent multi-horizon prospects located in PCA 332, including the Tigris-1. The Corporation believes that drilling success at Tigris-1 would allow Bengal to pursue a follow-up multi-well development program, as well as support the appraisal of other opportunities on PCA 332.

See "*General Development of the Business – Fiscal Year Ended March 31, 2022*", "*General Development of the Business – Fiscal Year Ended March 31, 2023*", "*General Development of the Business – Fiscal Year Ended March 31, 2024*" *and* "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Properties with No Attributable Reserves*".

Barrolka East Permit and Durham Downs East Block (controlling permit ATP 934)

In 2016, Bengal completed the geological and geophysical interpretation of the permit with a total of four prospect areas identified. In 2017, additional in-depth technical work on existing 2D seismic was concluded. This work involved an amplitude variation with offset ("**AVO**") process which helps to identify trends that exhibit Permian reservoir sand development. The AVO technique assesses variations in seismic reflection amplitude with changes in distance between shot points and receivers. AVO analysis allows geophysicists to better assess reservoir rock properties, including porosity, density, lithology and fluid content. This work helped high-grade areas for potential 3D seismic acquisition and was deemed to be integral to the de-risking process during a future drill location selection process.

During the final quarter of calendar 2019, Bengal filed a special amendment with the State of Queensland regulatory body, the regulatory authorities to reduce the initial work program on ATP 934 for the period ending February 28, 2021. This application was subsequently approved on April 24, 2020. In 2020 Bengal filed an ATP Renewal and Relinquishment application. This application was subject to one further relinquishment of 179,355 gross acres and was approved and effective March 1, 2021, ATP 934 was renewed for a period of six years over an area of 237 sub blocks (179,000 Gross/117,179 Net acres). The LWP was comprised of geological and geophysical studies and the drilling of up to four wells or the drilling of up to three wells and the shooting of 260 square kilometres of 3D seismic.

Santos Farm-in – ATP 934 Barrolka East Permit

On July 24, 2020, Bengal's 100% owned Australian subsidiaries executed a Farm-in Agreement with Santos, whereby Santos committed to pay 100% of the cost of drilling a well on the farm-in lands to test the Permian section and either case and suspend or abandon the well to earn a 60% working interest in 137 sub-blocks (approximately 103,000 Gross (62,000 Net) acres). The Legbar 1 Well was drilled in calendar Q4 of 2021 at no cost to Bengal. However, insufficient levels of commercial hydrocarbon pay were encountered and the Legbar 1 Well was plugged and abandoned. The Legbar 1 Well qualified as a part of the LWP for the ATP 934 tenement.

On April 24, 2020, the Corporation received regulatory approval for a special amendment to the initial work program on ATP 934, the Corporation's 100% owned natural gas exploration block. The Corporation had no further expenditure commitments on the permit before February 28, 2021, when the permit was up for renewal. As a condition of the approval of the special amendment, the Corporation agreed to relinquish an additional 17% of the permit in addition to the 33% mandatory relinquishment for a total of 50% (240 sub-blocks) of the acreage at the end of the first term on the permit. The acreage subject to the 50% relinquishment was determined by Bengal and consisted of the least prospective land (from a technical perspective) with the most challenging access conditions under the terms of the existing environmental authority granted by the regulator. In return, the Corporation was granted a reduction in the total commitment from $12.3 million to $1.2 million which amount had previously been expended.

Effective March 1, 2021, ATP 934 was renewed for a period of six years over an area of 237 sub blocks (179,000 Gross (117,179 Net) acres). The LWP is comprised of geological and geophysical studies and the drilling of up to four wells or the drilling of up to three wells and the shooting of 260 square kilometres of 3D seismic. During the year ended March 31, 2021, ATP 934 was evaluated for any impairment triggers according to International Accounting Standards 36. As the Corporation was aware that a reduction in commitment level would be granted prior to the 2021 year end, no impairment triggers were identified. For the period ending March 31, 2022, additional technical work was carried out on ATP 934 in the form of the identification of key 2D seismic lines for reprocessing and remapping of a series of previously identified prospects which further confirmed the presence and location of the said prospects.

In late 2023, the Queensland government released a document outlining its plans for increased restrictions to petroleum activities within the rivers and floodplains area of the Lake Eyre Basin catchment. Bengal's areas affected by this are the western portion of the Durham Downs East block of ATP 934 where Bengal holds a 40% interest, PCA 115 (Nubba) in which Bengal holds a 38% interest, and the PLs of Karnak and Ramses (PL 411 and PL188, respectively). Of these permits, work can continue to develop gas resources under a petroleum license, but all other permits will have until August 30, 2024 to obtain a petroleum lease before all activities will need to cease. For Durham Downs East, the operator has been approached for their views and a way forward. The operator is currently formulating a response to the government as their exposure is much larger. Neither of these assets have any carrying value in the Corporation's financial statements. Prospects within Barrolka East (ATP 934 – 100% WI), Ghina (PL 1109 – 100% WI), Wareena (PL1110-100% WI) and Tookoonooka (PCA 332 – 100% WI) are unaffected.

See "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Properties with No Attributable Reserves*".

PCA 155 Nubba/Yilgarn, (controlling permit ATP 752, Wompi-Block), Queensland, Australia

On the Wompi sub-block on March 31, 2017, Bengal was granted PCA 155 Nubba/Yilgarn. The PCA 155 Nubba/Yilgarn, Wompi sub-block comprises 22,487 Gross acres (8,563 Net acres). The PCA 155 for Nubba/Yilgarn was controlled by permit ATP 752. On March 28, 2022, Bengal Australia issued a Sole Risk Notice to the other two ATP 752 JV parties with a working interest in the tenement. Due to weather constraints, the Sole Risk Notice lapsed after 180 days and has not been re-issued. PCA 115 allows a further 15 years to assess commerciality on the 30 sub-blocks granted, however, with the advent of the new Lake Eyre Basin legislation, no further exploration or development activity is permitted, and the Corporation and its JV partners expect to relinquish the Nubba lands in due course. The Corporation did not perform any work on this permit during the fiscal year ended March 31, 2024

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, 2024. All the Corporation's production comes from its 30.357% working interest in the Cuisinier field located in the Barta Block of ATP 752 in Queensland Australia. Total field production for the year was 201,318 barrels of oil (net 62,000 barrels of oil).

	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)	% Oil
Total from Gross Proved Reserves:	**152**	**-**	**-**	**-**	**152**	**100**
Total from Gross Proved plus Probable Reserves:	**155**	**-**	**-**	**-**	**155**	**100**

Production History

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

	Quarter Ended			
	2024	2023		
	31-Mar	31-Dec	30-Sep	30-Jun
AVERAGE DAILY PRODUCTION[1]				
Light Crude Oil and Medium Crude Oil (Bbls/d)	162	174	176	176
Heavy Crude Oil (Bbls/d)	-	-	-	-
Natural Gas Liquids (Bbls/d)	-	-	-	-
Conventional Natural Gas (Mcf/d)	-	-	-	-
Total (BOE/d)	**162**	**174**	**176**	**176**
AVERAGE PRICE RECEIVED (NET OF TRANSPORTATION)[3]				
Light Crude Oil and Medium Crude Oil ($/Bbls)	123.36	100.48	119.75	104.12
Heavy Crude Oil (Bbls/d)	-	-	-	-
Natural Gas Liquids ($/Bbls)	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-
Total ($/BOE)	**123.36**	**100.48**	**119.75**	**104.12**
ROYALTIES PAID				
Light Crude Oil and Medium Crude Oil ($/Bbls)	9.04	12.80	6.24	7.04
Heavy Crude Oil (Bbls/d)	-	-	-	-
Natural Gas Liquids ($/Bbls)	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-
Total ($/BOE)	**9.04**	**12.80**	**6.24**	**7.04**
PRODUCTION COSTS				
Light Crude Oil and Medium Crude Oil ($/Bbls)	46.83	50.71	54.03	45.40
Heavy Crude Oil (Bbls/d)	-	-	-	--
Natural Gas Liquids ($/BOE)	-	-	-	-
Conventional Natural Gas ($/BOE)	-	-	-	-
Total ($/BOE)	**46.83**	**50.71**	**54.03**	**45.40**
NETBACK RECEIVED[4]				
Light Crude Oil and Medium Crude Oil ($/Bbls)	67.49	36.97	59.48	51.68
Heavy Crude Oil (Bbls/d)	-	-	-	-
Natural Gas Liquids ($/BOE)	-	-	-	-
Conventional Natural Gas ($/BOE)	-	-	-	-
Total ($/BOE)	**67.49**	**36.97**	**59.48**	**51.68**

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.
(3) Average price received does not include realized gain/loss on financial instruments.
(4) Netback per BOE is calculated by dividing revenue (including realized gain/loss on financial instruments) less royalties, operating and transportation costs by the total production of Bengal measured in BOE.

The following table indicates Bengal's average daily production from its important field, and in total, for the year ended March 31, 2024:

	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)
Australian Properties: Cuisinier	172	-	-	-	172
Total:	**172**	**-**	**-**	**-**	**172**

The Corporation's production for the year ended March 31, 2024, was 100% light crude oil (32° API or greater).

For the twelve months ended March 31, 2024, approximately 100% of the Corporation's gross revenue was derived from light crude oil and medium crude oil production.

DIVIDEND POLICY

Bengal has not paid any dividends on any outstanding Common 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.

DESCRIPTION OF CAPITAL STRUCTURE

Bengal is authorized to issue an unlimited number of Common Shares, of which 485,304,215 Common Shares are issued and outstanding as of the date hereof, and an unlimited number of Preferred Shares, of which none are issued and outstanding as of the date hereof. There are currently 10,620,000 options to purchase Common Shares outstanding with a weighted average exercise price of $0.08, of which 10,270,000 options to purchase Common Shares are vested.

The holders of Common Shares are entitled: (i) to receive notice of and to attend and vote at all meetings of shareholders of the Corporation (except meetings of holders of another class of shares); (ii) to receive such dividends declared by Bengal (subject to the preferences accorded to holders of Preferred Shares); and (iii) in the event of the voluntary or involuntary liquidation, dissolution or winding-up of the Corporation, or any other distribution of its assets among shareholders for the purpose of winding-up its affairs, to receive pro rata, all of the assets remaining for distribution after the payment to the holders of the Preferred Shares, in accordance with the preference on liquidation, dissolution or winding-up accorded to the holders of the Preferred Shares.

The Preferred Shares are issuable in series, with each series consisting of such number of shares and having such designation, rights, privileges, restrictions, and conditions as may be determined by the board of directors of the Corporation 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 holders of each series of Preferred Shares are entitled to preference over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares and may also be given such other preferences over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares as may be determined at the time of the 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 and Volume

The Common 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 Common Shares (as reported by the TSX) for the periods indicated.

Period	Low ($)	High ($)	Volume
2023			
April	0.04	0.075	234,315
May	0.055	0.07	127,463
June	0.04	0.06	439,571
July	0.045	0.065	275,466
August	0.04	0.055	158,239
September	0.04	0.06	251,741
October	0.035	0.05	124,371
November	0.02	0.035	873,802
December	0.02	0.03	268,962
2024			
January	0.025	0.035	268,153
February	0.02	0.025	173,287
March	0.02	0.03	82,715
April	0.02	0.035	447,485
May	0.025	0.035	125,593
June (1 to 28)	0.02	0.04	473,380

Prior Sales

During the year ended March 31, 2024, the Corporation did not grant any stock options or other securities not listed or quoted on a marketplace.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as of the date hereof.

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding

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 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.
Brian Moss[(2)(3)(4)(6)] Calgary, Alberta, Canada	Director	January 6, 2012	Director of Crown Point Energy Inc. and former President and Chief Executive Officer Crown Point Energy Inc. (formerly Crown Point Ventures Ltd.), a public oil and natural gas company, from November 9, 2016, to March 1, 2022. Prior thereto, Executive Vice President and Chief Operating

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
			Officer of Crown Point Energy Corp. from June 2012 to November 2016. Director of Crown Point Energy Inc. from May 2012 to April 2015. Director of Acquisition Oil Corporation, a private oil and natural gas company from March 2018 to present.
Robert Steele(1)(2)(3)(4)(5) 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.
William (Bill) Wheeler(1)(5) Vancouver, British Columbia, Canada	Director	January 6, 2012	Private investor. Director and President of Texada Capital Management Ltd., a private investment company since September 2011. Co-founder of Leith Wheeler Investment Counsel.
Peter Lansom(2)(3)(4) Greater Brisbane Area, Queensland, Australia	Director	September 28, 2021	Former Managing Director of Galilee Energy Limited from September 2013 to June 2021. Prior thereto, private advisor and consultant from March 2012 to September 2013. Prior thereto, Executive Director and Chief Operating Office at Eastern Star Gas from September 2007 to November 2011. Prior thereto, Chief Petroleum Engineer for Origin Energy May 2005 to September 2007.
Barry Herring(1) Calgary, Alberta, Canada	Director	January 18, 2024	Former Chief Financial Officer of Trion Battery Technologies from 2022 to 2023. Consultant for TransAm Piping and Products Ltd. from 2017 to 2021.
Richard Edgar Calgary, Alberta, Canada	Executive Vice President	N/A	Executive Vice President of Bengal since September 2014. Director/President of Poplar Creek Resources Inc., an unlisted public company since July 2009. Director of Shelton Canada Corporation from December 2009 to present.
Jerrad Blanchard Calgary, Alberta Canada	Chief Financial Officer	N/A	Appointed Chief Financial Officer March 8, 2021. Mr. Blanchard has over 15 years' experience in the oil and gas sector and has demonstrated expertise in all aspects of strategy, corporate finance, implementation of controls, financial reporting, and governance. In addition to Bengal Energy Ltd., he has acted as Chief Financial Officer for Winstar Resources Ltd., a public international oil and gas exploration and production company with operations in North Africa and Eastern Europe as well for Northern Silica Corporation, a mining company with producing assets in Canada. Mr. Blanchard is a chartered professional accountant and began his career in the audit practice of PricewaterhouseCoopers with a focus on junior and international oil and gas exploration and production companies.
Kai Eberspaecher Wakerley, Queensland Australia	Chief Operating Officer	N/A	Former Consulting Practice Lead for Operational Excellence in the Asia Pacific Region for Advisian (WorleyParsons Group) serving Resource and Energy Infrastructure Industries. 2015 – 2018. Prior 10 years, various senior leadership positions in Operations and Capital Projects for BG Group.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Health, Safety and Environmental Committee.
(5) Member of the Governance and Nominating Committee.
(6) Interim Chair of the Audit Committee from September 21, 2023 – January 18, 2024.

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

As at June 28, 2024, the directors and executive officers of Bengal set forth above, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 405,679,448 Common Shares or approximately 83.6%of the issued and outstanding Common Shares, and 412,400,579 Common Shares or approximately 85% of the issued and outstanding Common Shares on a fully diluted basis (including the exercise of outstanding options to purchase Common Shares).

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed herein, no director, executive officer, or a shareholder holding a sufficient number of securities that materially affect the control of the Corporation, as applicable: (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 and officer of Poplar Creek Resources Inc. when the company was subject to cease trade orders by the Alberta Securities Commission, British Columbia Securities Commission and Ontario Securities Commission on May 9, 2014, for failure to file annual audited financial statements within the time frame allowed. Poplar Creek subsequently filed the required audited financial statements and MD&A and on September 24, 2019, the Alberta, British Columbia and Ontario Securities Commissions issued a revocation order lifting the cease trade order. In addition, a similar cease trade order was issued by the Alberta and Ontario Securities Commissions on May 6, 2022 for failure to file annual audited financial statements within the time frame allowed. The audited financial statements and MD&A were subsequently filed by Poplar Creek and a revocation order was issued by the Alberta and Ontario Securities Commissions on August 3, 2022.

Mr. Steele was a director of Gamet Resources Limited ("**Gamet**") when the company filed a Notice of Intention to File a Proposal under the BIA on March 17, 2016. The proposal of Gamet was approved by the Alberta Court of Queen's Bench on September 28, 2016. Mr. Steele resigned as a director of Gamet on August 27, 2016.

Mr. Blanchard was the Chief Financial Officer of Northern Silica Corporation and director of Heemskirk Mining Pty. Ltd., Heemskirk Canada Holdings Limited, Heemskirk Canada Limited, Custom Bulk Services Inc. and HCA

Mountain Minerals (Moberly) Limited (collectively, the "**NSC Companies**") when the NSC Companies became subject to an initial order under the Companies' Creditors Arrangement Act (the "**CCAA**"). On November 23, 2020, the NSC Companies obtained a court order to terminate the CCAA proceedings that were commenced on June 30, 2020, by QMetco Limited and Taurus Resources No. 2 B.V., secured creditors of the NSC Companies (the "**Secured Creditors**"). On November 23, 2020, the Court ordered that the CCAA proceedings be terminated following the sale of all the NSC Companies Assets to a related entity of the Secured Creditors under an approved sales and investment solicitation process.

Conflicts of Interest

The directors or officers of the Corporation may also be directors or officers of other oil and natural 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.

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 and Relevant Education and Experience

The members of the Audit Committee are Barry Herring (Chair), William (Bill) Wheeler and Robert Steele. Brian Moss served as the interim Chair of the Audit Committee from September 21, 2023 – January 18, 2024. 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. Barry Herring, Chair

Mr. Herring graduated with a Bachelor of Business Administration degree from the University of Regina in 1978 and is a Chartered Professional Accountant with 40 years of experience. He was the Chief Financial Officer of Trion Battery Technologies from 2022 to 2023 and a consultant for TransAm Piping and Products Ltd. from 2017 to 2021. Mr. Herring has served as the Chief Financial Officer of both public and private entities and has managed several initial public offerings and merger transactions.

Mr. Robert Steele

Mr. Steele graduated with an Arts and Science degree in 1968 and a degree in Electrical Engineering both 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.

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 investment company.

Pre-Approval of Policies and Procedures

Pursuant to the requirements of the Audit Committee Mandate and Terms of Reference, 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, 2024	Financial Year Ending March 31, 2023
Audit Fees(1)	$122,000	$115,000
Audit-Related Fees(2)	--	-
Tax Fees(3)	$15,000	$10,000
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.

HUMAN RESOURCES

The operations and management of Bengal requires the recruitment and retention of a skilled workforce, including engineers, geologists, geophysicists, finance, marketing, and human resource professionals and other key personnel required to find, acquire, develop and operate the Corporation's assets, and transport and market its production.

As at March 31, 2024, Bengal employed 4 full-time employees and 1 part-time consultant 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 – 5th Avenue S.W., Calgary, Alberta T2P 4B9.

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the Common 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, 2024, 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.

Mr. Wheeler currently owns, directly or indirectly, or exercises control or direction over 398,679,360 Common Shares, representing approximately 82.2% of the total issued and outstanding Common Shares as at the date of this Annual Information Form.

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 NI 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 NI 51-102) 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 are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules 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, as well as with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, and foreign countries, such as Australia, all of which investors in the oil and natural 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 natural gas industry in Australia.

Pricing and Marketing

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 oil and condensate exist in Australia and low-sulphur light crude oil finds a ready domestic and overseas market. Gas is typically traded in long term gas sales agreements. The gas distribution sector is dominated by two main participants forming natural monopolies: APA Group and Jemena serving the East Coast. The buyers are typically power generating utilities and Chemical & Industrial users.

Royalties and Incentives

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 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. PRRT is applicable to all Australian offshore and certain onshore oil and natural 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 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 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 oil once a threshold of 30 MMbbls is reached and if then exceed 3 MMbbls annually. A credit is allowed for the purposes of PRRT.

The royalty previously imposed by State governments on oil and natural gas production in Australia was 12.5% of the wellhead value. However, in Queensland, royalties are calculated based on a tiered royalty rate to the volume of petroleum produced. Under the volume model, royalties are calculated by applying a prescribed rate to the volume of liable petroleum produced during a return period. There are different rates depending on the class of petroleum (i.e., domestic gas, supply gas, project gas or liquid petroleum).

In onshore areas that are affected by native title additional compensation may be payable to recognized First Nation Australian title holders. This compensation is negotiable and 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 First Nations 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 receive 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

Amendments to Queensland resources legislation were proposed by the *Natural Resources and Other Legislation Amendment Bill 2019* (the "**NROLA Bill**"), with key changes to affect industry's management of petroleum exploration tenure. On May 15, 2019, the *Natural Resources and Other Legislation Amendment Act 2019* (the "**NROLA Act**") was passed by Parliament.

The key amendments to the *Mineral Resources Act 1989* (the "**MRA**"), *Mineral and Energy Resources (Common Provisions) Act 2014* (the "**MERCPA**") and the *Petroleum and Gas (Production and Safety) Act 2004* (the "**PG Act**") that affect aspects of the management of petroleum exploration tenements are detailed below.

Work programs for ATPs

Work programs for ATPs are either activities-based or outcomes-based, depending on the nature of the tenure.

Activities-based programs will remain as per the current requirements for work programs. However, outcomes-based programs are a new concept (intended to provide flexibility to the tenure holder) and must detail four components:

- the outcomes proposed to be pursued during the term;
- the strategy for pursuing the outcomes;
- the information and data proposed to be collected as an indication of mineralisation during the term; and
- the existing requirement to provide the estimated human, technical and financial resources proposed to be committed during the term.

Outcomes-based work programs are generally accepted for non-competitive-tender applications (subject to some exceptions), with activities-based programs generally being the default position for competitive tenders. However, even for competitive tenders, a call for tender may specify that the tender is required to be accompanied by an outcomes-based work program (for example, where it is a greenfield site).

Relinquishment of ATPs

The NROLA Act streamlines the relinquishment requirements of ATPs by reducing the frequency of relinquishment.

ATPs

The relinquishment requirements for ATPs have been amended from 8.33% per year to 50% per year by the "relinquishment day" (being the day before the 6^{th} anniversary of the day the ATP took effect). This applies to ATPs granted after May 25, 2020. ATPs existing prior to the amendments are not affected by these changes.

Variation of conditions of ATPs

The Minister is permitted to amend the conditions of an ATP at any time (without application by, or seeking the views of, the holder). This power may be exercised by the Minister if exceptional events apply. An exceptional event as defined in the MRA means an event that: (i) affects the carrying out of authorized activities under the permit; (ii) is beyond the control of the holder of the permit; and (iii) could not reasonably have been prevented by the holder of the permit. An exceptional event does not include a takeover bid under the *Corporations Act 2001 (Cth)*, Chapter 6 made or proposed by another entity in relation to the holder of the permit. The PG Act contains an almost identical definition.

The NROLA Act also limits the grounds of an ATP holder to apply for a special amendment of conditions (in the case of an ATPs). Such applications may now only be made where there is an exceptional event or where the relevant ATP is part of an exploration project. An exploration project as defined in the PG Act means a project involving 2 or more ATP that have a unifying exploration purpose.

The amendments also limit the circumstances in which an extension to the period of a work program for an ATP will be granted.

Prospective future regulatory environment

Mineral ownership in Australia is governed by the respective state governments who grant tenements for the exploration of petroleum and natural gas. While not the same, largely the process from state to state is similar. Oil and natural gas companies typically submit applications to the applicable state government for exploration permits or an ATP in response to invitations to a bid made in government gazettals (onshore and offshore). Within the applications, companies outline a schedule of work programs that 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 First Nation 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 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. Changes to the PG Act announced by the Queensland State Government on May 28, 2014, may extend onshore ATP work permits by 2 years to 6 years. Generally, each state government will reserve unto itself a royalty when production commences which runs with the life of the relevant PL. 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 ATPs held by the Corporation are granted for a period of 12 years. All phases of the oil and natural gas exploration, development and production activities are regulated in varying degrees by the Australian regulatory authorities. Where the ATP has an initial term of 12 years, this period may be subdivided into 3, 4-year periods. During the first 4-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 4-year period commences and at the end of the last period remaining land must be relinquished. Alternatively, for ATPs existing prior to the amendments, 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 12th year, all the land will have been relinquished that has not been a part of a commercial discovery. Commercial discoveries are held under PLs which are exempt from relinquishment and stay active until final field abandonment or the end of the specified term of the PL (generally 30 years). For ATPs granted after May 25, 2020, relinquishment of 50% of the original notional sub-blocks is required by the end of year 6.

Queensland – PCAs

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 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.

Regulatory Authorities and Environmental Regulation

In Queensland, the state government is preparing changes to the Regional Planning Interests Regulation 2014 (QLD) to better protect the Queensland Lake Eyre Basin's environment.

This includes introducing regulation of future petroleum activities in the sensitive rivers and floodplains, such that following a transitional process no new gas or oil exploration, or production leases will be allowed in the mapped Designated Precincts.

Bengal's Environment Authorities ("**EAs**") are subject to the provisions of the *Environmental Protection Act 1994* (Qld) (the "**EP Act**"). While the regulations made under the EP Act were updated in 2019, they remain in substantially similar form to the existing legislation and the amendments to the regulations incorporate current drafting practices and the effective operation of the EP Act.

No recent legislative changes have occurred to the EP Act that change the scope of the 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 (the "**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. For petroleum titles 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.

Changes to the OPGGS Act came into effect through the *Offshore Petroleum and Greenhouse Gas Storage Amendment (Miscellaneous Amendments) Act 2019* (Cth). Relevantly, the changes:

a) strengthen NOPSEMA's investigative and enforcement powers; and

b) formally transfer various regulatory functions from the Minister to NOPSEMA (which NOPSEMA had already been exercising under delegation from the Minister).

The practical effect of these amendments on Bengal's operations is minimal, and the amendments largely relate to providing NOPSEMA with greater investigatory and other powers, and a wider array of enforcement tools, including penalties and enforceable undertakings.

In addition, the *Offshore Petroleum and Greenhouse Gas Storage Amendment (Cross-Boundary Greenhouse Gas Titles and Other Measures) Act 2020* (Cth) amended the OPGGS Act to enable title administration and regulation of a greenhouse gas storage formation that straddles the boundary between state and Northern Territory coastal waters and Commonwealth waters. This Act allowed for cross-boundary single gas titles, particularly from state and territory coastal waters to Commonwealth waters and enabled the unification of two greenhouse gas titles where a titleholder has reasonable grounds to suspect that there is a geological formation that sits on either side of two title areas and allow the Commonwealth to facilitate this through a cross-boundary authority.

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 "**EP Amendment Act**"). The EP Amendment Act was introduced to compel responsible persons connected to corporations in financial distress to meet environmental responsibilities. The EP Amendment Act amends the EP Act to empower the Queensland Department of Environment and Science (the "**DES**") to issue related persons of the Operators (as defined below) 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 DES a bank guarantee or other form of security 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 Department of Environment and Heritage Protection to step in and remediate a site, and then recover its rehabilitation costs from the EPO recipient.

The EP Amendment Act also confers power on the DES 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.

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

Bengal is not aware of any negative or positive effects environmental regulations will have on its activities.

Liability Management Rating Programs

Queensland, Australia

The *Mineral and Resources (Financial Provisioning) Act 2018* (Qld) came into force on 1 April 2019, which replaced the previous financial assurance arrangements for resource activities under the EP Act have been with the Financial Provisioning Scheme (the "**Scheme**"). The Scheme imposes an automatic Estimated Rehabilitation Cost (the "**ERC**") condition on all EAs (replacing existing financial assurance requirements). The ERC figure is based on the likely costs and expenses that the Queensland Government may incur for rehabilitating or managing disturbance of the land.

The Scheme is administered by the Scheme manager, a statutory officer supported by Queensland Treasury.

The purpose of the Scheme is to improve the State's management of its financial risk in the event that holders of a resource activity environmental authority (holders) or small-scale mining tenure ("**SSMT**") fail to comply with their environmental management and rehabilitation obligations. Over time, the Scheme will also provide funds to support rehabilitation of abandoned mines and expand research into mine rehabilitation.

The Scheme manager is responsible for administering all SSMT and holders' financial provisioning on behalf of the State of Queensland. To enable this, all holders and SSMT financial assurance (called surety in the Act) held by the DES and the Department of Resources were transferred to the Scheme from April 1, 2019.

Under the Scheme, SSMTs and holders with an ERC below $100,000 will continue providing surety and will not be part of the annual risk category assessment process and landholders with an ERC of at least $100,000 will be transitioned across to the Scheme manager risk category assessment process over 3 years (from April 1, 2019). The assessment process will determine whether the holder will be required to provide a contribution to the Scheme's financial provisioning fund and/or to provide surety to the Scheme manager (all existing financial assurance is taken to be surety given under the EP Act). The *Environmental Protection and Other Legislation Amendment Act 2020* (Qld) also amended the EP Act in relation to rehabilitation and post-surrender obligations. Notably, a holder may now be required to make a residual risk payment into the residual risk fund to ensure that any ongoing management or remediation of the site will be covered, after the financial assurance (or security deposit) provided to the Scheme has been returned and the EA has been surrendered by the holder. The residual risk payment is intended to cover the likely costs and expenses incurred by the department to manage and remediate the resource activity after financial assurance has been returned.

Climate Change Regulation

Climate change regulation at both the federal and state level in Australia has the potential to significantly affect the regulatory environment of the oil and natural gas industry. 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.

On July 17, 2014, the *Clean Energy Legislation (Carbon Tax Repeal) Act 2014* 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 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 and Energy 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 26% – 28% below 2005 levels by 2030. 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 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.

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. The risks discussed below are based on certain assumptions made by the Corporation which later may prove to be incorrect or incomplete. Investors are encouraged to perform their own investigation with respect to the business, financial condition and prospects of the Corporation.

The Corporation's business could also be affected by additional risks and uncertainties not currently known to the Corporation or that it currently deems to be immaterial. If any of these risks occur, it could materially harm the Corporation's business, financial condition, results of operations and cash flows, or impair the Corporation's ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Common Shares could decline, and investors could lose all or part of their investment. Before deciding whether to invest in any equity or debt, investors should carefully consider the risks set out below. If any of the risks described below materialize, the Corporation's business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to the Corporation or that the Corporation currently views as immaterial may also materially and adversely affect the Corporation's business, financial condition or results of operations. The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "Forward-Looking Statements".

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop, and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition or participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil or natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion, and operating costs.

Drilling hazards, environmental damage and various field operating conditions could increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, 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, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance, business interruption insurance, control of well insurance and Director and Officer insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Risk Factors – Insurance*". In either event, the Corporation could incur significant costs.

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 natural 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. Bengal carefully selects its contractors to execute drilling, completion, engineering, and construction as well as operational activities to ensure that value is maximized. 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.

Risks Associated with Foreign Operations

There are significant risks associated with carrying on foreign operations.

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, border disputes, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labour disputes, sudden changes in laws, government control over domestic oil and natural 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

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities.

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil and natural gas to commercial markets or contract for the delivery of oil by rail. Deliverability uncertainties related to the distance of the Corporation's reserves from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and processing and storage facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Oil and natural gas prices may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions of the Organization of Petroleum Exporting Countries, political uncertainties, sanctions imposed on certain oil producing nations by other countries, the Russian Ukrainian war and conflicts in the Middle East, or other adverse economic or political development in the United States, Europe, or Asia. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Prices of oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets.

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. 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.

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.

Gathering and Processing Facilities, Pipeline Systems and Trucking

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and tanker truck loading and unloading terminals may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas.

Bengal delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by tanker truck. 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 tanker trucks. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and truck loading and unloading terminals 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. Unexpected shutdowns 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.

Bengal's oil production is 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 because of normal servicing requirements or because 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.

Market Price

The trading price of the Corporation's Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry

The trading price of the 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, current perceptions of the oil and natural gas market and worldwide pandemics. In recent years, the volatility of commodities prices has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have decided to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity, and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

The Corporation is uncertain as to the likelihood of making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings, proceeds from asset sales and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or those affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

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 favourable terms, may be utilized to help fund Bengal's capital program.

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties.

In most instances, 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 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. This 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 a working 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 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 effect on the Corporation's financial and operational results.

Abandonment and Reclamation Costs

The Corporation may have to pay certain costs associated with abandonment and reclamation.

The Corporation will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Corporation's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while the Corporation accrues a reserve in its financial statements for such costs in accordance with International Financial Reporting Standards ("**IFRS**"), such accruals may be insufficient.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, the Corporation may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If the Corporation establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition.

The exchange rate for the Australian dollar has weakened slightly against the Canadian dollar throughout the year. Bengal, through its subsidiary Bengal Australia, 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 and interest rates, there is a credit risk associated with counterparties with which the Corporation may contract. 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 of funds available to fund its exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the Common Shares.

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counterparty risk.

From time to time, the Corporation may enter into agreements to receive fixed prices or derivative contracts 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 or natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian dollars 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.

Expiration of Licences and Leases

The Corporation or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry.

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 a licence or lease fails to meet the specific requirement of the 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 and the associated abandonment and reclamation obligations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by current economic conditions and global market volatility.

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities from time to time, the Corporation may require additional financing 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 its operations.

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 suitable 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 because 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 or acquisition plans may result in a delay in development of or production from the Corporation's properties.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of comparable 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.

Asset Concentration

The Corporation's operations and drilling activities are vulnerable to risks associated with operating in a limited geographic area

The Corporation's producing and undeveloped properties are geographically concentrated in the Cooper Basin in Australia. Demand for and costs of personnel, equipment, power, services, and resources in such geographic area remain high. This high level of demand could result in a delay or inability to secure such personnel, equipment, power, services, and resources. Any delay or inability to secure the personnel, equipment, power, services, or resources could result in oil and natural gas production volumes being below the Corporation's forecasts. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on the Corporation's financial conditions, results of operations, cash flow, and profitability.

As a result of this geographical concentration, the Corporation may be disproportionately exposed to the impact of delays or interruptions of operations or production in this area caused by external factors such as governmental regulation, provincial politics, Indigenous rights claims, market limitations, supply shortages, or extreme weather-related conditions.

Reserves Estimates

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect, and which may affect the Corporation.

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 reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) 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 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 and such variations could be material.

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

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom 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

Seismic data may not be indicative of drilling results.

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 because 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.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, and cost overruns and marketing challenges.

The Corporation manages a variety of small and large projects in the conduct of its business. Project interruptions 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 and the cost of accessing of processing capacity;
- the availability, proximity and the cost 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 and severe weather events, including fire, drought, extreme cold and flooding;
- the availability of drilling rigs and related equipment;
- supply chain disruptions for oilfield equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour;
- political uncertainty;
- environmental and Indigenous activism that may result in delays or cancellations of projects; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation may 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 natural 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

The availability of required infrastructure and its development is not certain.

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 natural 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.

First Nation Claims

First Nation claims may affect the Corporation.

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.

Dilution

The Corporation may issue additional Common Shares or other dilutive securities, diluting current shareholders.

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 to shareholders.

Regulatory Landscape

Modification to current, or implementation of additional, regulations may reduce the demand for oil and natural gas, increase the Corporation's costs and delay planned operations

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for 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.

Further, third party challenges to regulatory decisions and orders can reduce the efficiency of the regulatory regime, as the implementation of decisions and orders may be delayed resulting in uncertainty and interruption to the business of the oil and natural gas industry.

To conduct oil and natural gas operations, the Corporation will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. 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* and the *Investment Canada Act* could negatively affect the Corporation's 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Australia, Government and Regulations

All phases of the oil and natural 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, payment of statutory dues, royalties, expropriation of property, environmental protection, land access, native title, workplace health and safety in the office and on remote sites, corporate manslaughter and fair employment conditions. In addition, the award of an ATP, PCA or PL and matters relating to the implementation and conduct of operations under these agreements are subject to the consent of the relevant State 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 (offshore assets) and relevant State governments (onshore assets). This prescriptive regulatory burden and possible delays inherent in that regulatory environment may decrease the risks associated with the Corporation's exploration and production activities and increase the Corporation's costs of doing business due to additional risk management systems and compliant work practices compared to North American operations.

On July 11, 2023, a Mandatory Code of Conduct for the Gas Industry (the "**Gas Market Code**") commenced. Under the Gas Market Code, a cap on the price of gas was introduced at $12/gigajoule by the Australian Federal Government. Smaller gas producers (producing less than 100 peta joules of gas per annum) and who supply that gas to the domestic market are automatically exempt. Otherwise, price caps maintained at $12/gigajoule may apply, although producers over 100 peta joules may be eligible to apply for an exemption from the Gas Code's pricing provisions if they negotiate a satisfactory enforceable domestic supply commitment.

Industry Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources.

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

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result.

The level of activity in the oil and natural gas industry is influenced by seasonal weather patterns. In Australia, the level of activity and production may be influenced by seasonal weather fluctuations such as, but not limited to, flooding. 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 of the Corporation.

Third Party Credit Risk

The Corporation is exposed to credit risk of third-party operators or partners of properties in which it has an interest.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future JV 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 or other 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 the Corporation's JV partners may affect a JV 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, make a proposal, or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Environmental Regulation

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources.

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, the initiation and approval of new oil and natural gas projects, and restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets 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. New environmental legislation may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental 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 liabilities and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

New anti-greenwashing rules limit the permissibility of certain sustainability-related disclosures.

On June 20, 2024, Bill C-59 received royal assent, thereby enacting certain changes to the *Competition Act* to address "greenwashing", meaning false, misleading, or deceptive environmental claims made for the purpose of promoting a product or a business interest. Under the new rules, the use of environmental-related words and phrases, for instance "sustainable", is problematic given that such terms can be vague and can mean different things to different people. How the new rules will be interpreted and applied is currently unclear. Companies found to have made representations that violate the rules, intentionally or inadvertently, could be subject to an administrative penalty for the greater of $10 million for the first order and $15 million dollars for any subsequent order, and 3% of the corporation's annual worldwide gross revenues.

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact the Corporation

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce, could result in the failure to implement the Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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. The Corporation does not have any key personnel insurance in place.

Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of vital importance. In addition, the Corporation's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Corporation's properties may result in a financial loss.

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 Corporation's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by the Corporation.

If a defect exists in the chain of title or in the Corporation's right to produce, or a legal challenge or legislative change arises, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation.

Bengal's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blowouts, 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.

The Corporation's insurance policies are renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies, can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Corporation to decide to reduce or possibly eliminate coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of which may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Corporation's overall risk exposure could be increased, and the Corporation could incur significant costs.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation.

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to its business, operations, or affairs. 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 would 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

Taxation authorities may reassess the Corporation's tax returns.

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 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.

Non-Governmental Organizations

The Corporation's properties may be subject to action by non-governmental organizations or terrorist attack.

In addition to the risks outlined above related to geopolitical developments, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack, physical sabotage or public opposition. Such public opposition could expose the Corporation to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support from the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack or sabotage, 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 such risks.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved, and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

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 and assets 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 the resources 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, if disposed of, may realize less on disposition than their carrying value on the financial statements of the Corporation.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete.

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 implement and benefit from technological advantages. 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. 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, potentially in a material way.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows.

There can be no assurance that the Australian, Queensland or South Australia state governments or the Canadian Federal Government will not adopt new royalty regimes, or modify the existing ones, which may affect the economic viability of the Corporation's projects. An increase in royalties will reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Climate Change

Climate change may pose varied and far-ranging risks to the business and operations of the Corporation, both known and unknown, that may adversely affect the Corporation's business, financial condition, results of operations, prospects, reputation, and share price.

Climate Change

Climate change concerns could result in increased operating costs and reduced demand for the Corporation's products and shares, while the potential physical effects of climate change could disrupt the Corporation's production and cause it to incur significant costs in preparing for or responding to those effects.

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially fossil fuel combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of greenhouse gases ("**GHG**"), including emissions of carbon dioxide and methane from the production and use of oil and natural gas. Most countries across the globe, including Canada and Australia, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. Individuals, governmental authorities, or other organizations may make claims against oil and natural gas companies, including the Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Corporation, impact its operations, and have an adverse impact on its financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing and providing insurance coverage to, oil and natural gas and related infrastructure businesses and projects. The impact of such efforts requires the Corporation's management to dedicate significant time and resources to these climate change-related concerns, which may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and the Corporation's cost of capital and access to the capital markets.

Emissions, carbon, and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, in June 2023 the IFRS issued two new international sustainability disclosure standards with the aim to develop sustainability disclosure standards that are globally consistent, comparable, and reliable. The Canadian Securities Administrators had previously published Proposed National Instrument 51-107 – *Disclosure of Climate-Related Matters* and its proposed Companion Policy 51-107CP, intended to introduce climate-related disclosure requirements for reporting issuers in Canada. It is expected that the introduction of the new international standards will instruct how new Canadian sustainability disclosure standards are finalized. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Climate Change Regulation*".

Physical risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, drought and wildfires may restrict the Corporation's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury because of dangerous working conditions. Certain of the Corporation's assets are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Inflation and Rising Interest Rates

A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows.

Recently, Canada, Australia and other countries have experienced high levels of inflation, supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs and commodity prices, and additional government intervention through stimulus spending and additional regulations. These factors have increased the operating costs of the Corporation. The Corporation's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows.

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects. The oil and natural gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available at reasonable prices when required. A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows.

In addition, many central banks including the Bank of Canada have taken steps to raise interest rates in an attempt to combat inflation. The rise in interest rates has impacted the Corporation's borrowing costs. The increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Corporation. Rising interest rates could also result in a recession in Canada, Australia or other countries. A recession may have a negative impact on demand for oil and natural gas, causing a decrease in commodity prices. A decrease in commodity prices would immediately impact the Corporation's revenues and cash flows and could also reduce drilling activity on the Corporation's properties. It is unknown how long inflation will continue to impact the economies of Canada and Australia and how inflation and rising interest rates will impact oil and gas demand and commodity prices.

Dividends

The Corporation does not pay dividends and there is no assurance that it will do so in the future.

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

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation.

In the normal course of the Corporation's operations, it may become involved in, be named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, and 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 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 effect on the Corporation's financial condition. Also see "*Legal Proceedings and Regulatory Actions*".

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants.

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 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 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.

Forward-Looking Statements

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

Expanding the Corporation's business exposes it to new risks and uncertainties.

The operations and expertise of the Corporation's management are currently focused primarily on oil and natural 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 and may acquire different energy related assets. As a result, the Corporation may face unexpected risks or, alternatively, its exposure to one or more existing risk factors may be significantly increased, which may in turn result in the Corporation's future operational and financial conditions being materially adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations, and cash flow.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil and natural gas. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flow by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Geopolitical Conflicts

The Corporation's business may be adversely affected by geopolitical conflicts abroad.

Israel-Palestine War

On October 7, 2023, Hamas terrorists infiltrated Israel's southern border from the Gaza Strip and conducted a series of attacks on civilian and military targets. Hamas also launched extensive rocket attacks on the Israeli population and industrial centres located along Israel's border with the Gaza Strip and in other areas within the State of Israel. Following the attack, Israel's security cabinet declared war against Hamas and the military campaign against these terrorist organizations has launched a series of responding attacks in Palestine.

The outcome of the conflict has the potential to have wide-ranging consequences on the world economy. Global oil prices dropped at the beginning of the Israel-Palestine war and major events occurring in connection with the ongoing conflict could affect global oil prices in the future. While neither Israel nor the Gaza Strip are significant oil producers, there is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the world's biggest oil producers. To date, these events have not impacted the Corporation's ability to carry on business, and there have been no significant delays or direct security issues affecting the Corporation's operations, offices or personnel. The long-term impacts of the conflict remain uncertain, and the Corporation continues to monitor the evolving situation.

Russian Ukrainian War

In February 2022, Russian military forces invaded Ukraine. Ukrainian military personnel and civilians continue to actively resist the invasion. Many countries throughout the world have provided aid to Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in its resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. Additionally, certain countries including Canada have imposed strict financial and trade sanctions against Russia. The outcome of the ongoing conflict remains uncertain and may have wide-ranging consequences on the peace and stability of the region and the world economy.

Geopolitical Risks

The Corporation's business may be adversely affected by recent political and social events and decisions made in Canada, Australia, the United States, Europe, and elsewhere.

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 the Common Shares.

The Corporation's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to an industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Corporation's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licences and permits for the Corporation's activities or restrict the operation of third-party infrastructure on which the Corporation relies. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Corporation's results.

Other government and political factors that could adversely affect the Corporation's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Corporation's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease demand for the Corporation's products.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact the Corporation's operations and financial position.

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure, and its 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 its land base, manage financial resources, analyze seismic information, administer contracts with 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 the Corporation's competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim of a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email, request recipients to send a password or other confidential information through email, or to download malware.

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites for business or personal purposes may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. The Corporation is aware of these risks and continues to monitor behaviour within its team to mitigate such risks. Despite these efforts, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

The Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices. The Corporation also employs encryption protection of its confidential information, and all its computers and other electronic devices. Despite the Corporation's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets, and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Corporation's performance and earnings, as well as reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. 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.

The handling of secure information exposes the Corporation to potential data security risks that could result in monetary damages against the Corporation and could otherwise damage its reputation, and adversely affect its business, financial condition and results of operations.

The protection of customer, employee, and company data is critical to the Corporation's business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, employee, or company data could attract a substantial amount of media attention, damage the Corporation's customer relationships and reputation, and result in lost sales, fines, or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request the Corporation to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, the Corporation may have to modify its operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect its reputation, business, financial condition and results of operations.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees.

The Corporation's business, operations or financial condition may be negatively impacted by any negative public opinion toward the Corporation or because of any negative sentiment toward, or in respect of, the Corporation's reputation with stakeholders, special interest groups, political leadership, the media, or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as such groups' opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, the Corporation's reputation could be impacted by negative publicity related to loss of life, injury or damage to property and the environment caused by the Corporation's operations. In addition, if the Corporation develops a reputation of having an unsafe work site, this may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate-related litigation against governments and fossil fuel companies may impact the Corporation's reputation. See "*Risk Factors – Climate Change*".

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Corporation's reputation. Damage to the Corporation's reputation could result in negative investor sentiment toward the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities.

Changing Investor Sentiment

Changing investor sentiment toward the oil and natural gas industry may impact the Corporation's access to, and cost of, capital.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation, and Indigenous rights have affected certain investors' sentiments toward investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer willing to fund or invest in oil and natural gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the board of directors, management, and employees of the Corporation.

Failing to implement the policies and practices as requested by investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Corporation, may limit the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities even if the Corporation's operating results, underlying asset values or prospects have not changed.

Intellectual Property Litigation

Unauthorized use of intellectual property may cause the Corporation to engage in or be the subject of litigation.

Due to the rapid development of oil and natural gas technology, in the normal course of the Corporation's operations, the Corporation may become involved in, be named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or which the Corporation initiates against others it believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to: (a) pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. However, the Corporation may not be successful in such development or acquisition, or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

Significant Shareholder

Mr. Wheeler currently owns, directly or indirectly, or exercises control or direction over 398,679,360 Common Shares, representing approximately 82.2% of the total issued and outstanding Common Shares as of the date of this Annual Information Form. As a result, such person exercises significant control over the Corporation, giving the shareholder the ability to, among other things, affect the voting results with respect to the election of directors and the approval of significant corporate transactions, including any change of control transaction. Such person will generally have the ability to influence the outcome of any matter submitted for the vote or consent of our shareholders. In some cases, the interests of such person may not be the same as those of our other shareholders. The effect of such person's rights, influence and size of ownership position may impact the price that other investors are willing to pay for our securities. If any of the foregoing person sells a substantial number of the Common Shares in which they own in the public market, or otherwise, the market price of the Common Shares could fall.

Pipeline Systems

Pipeline interruptions or capacity constraints may have a negative impact on the Corporation's ability to transport and market its products

The interruption of firm pipeline transportation has and may continue to affect the oil and natural gas industry and limit the ability to fully produce and market oil and natural gas production. In addition, the pro-rationing of capacity on interprovincial pipeline systems may also affect the ability to export oil and natural gas. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators may also affect the Corporation's production, operations, and financial results. The Corporation's production could be adversely impacted by both firm and interruptible transportation service curtailments.

Impact of Future Financings on Market Price

The Corporation's future financings may negatively impact the market price of the Common Shares

In order to finance future operations or acquisition opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation's securities will have on the market price of the Common Shares or the amount of dilution, if any, to current shareholders as a result of such financings.

Disposal of Fluids used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products while at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position; the Corporation's operations are dependent upon the availability of water and its ability to dispose of produced water from drilling and production activities

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations to stimulate the production of oil and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing have resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity and completely banning hydraulic fracturing in other areas. Any new laws, regulations, or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, and/or third party or governmental claims, and could increase the Corporation's costs of compliance and doing business, as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where the Corporation operates could result in the Corporation being unable to economically recover its oil and gas reserves, which would result in a significant decrease in the value of the Corporation's assets.

Water is an essential component of the Corporation's drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Corporation is unable to obtain water to use in its operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on the financial condition, results of operations, and cash flows of the Corporation.

The Corporation must dispose of the fluids produced from oil and natural gas production operations, including produced water. It does so directly or through the use of third party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighbouring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation or by commercial disposal well vendors that the Corporation may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Corporation or its vendors having to limit disposal well volumes, disposal rates, pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition, and results of operations.

Tax Horizon

The Corporation's projections regarding its tax horizons may be inaccurate, resulting in a requirement to pay taxes sooner than expected

It is expected, based upon current legislation, the projections contained in the GLJ Report and various other assumptions regarding the timing of cash tax payments. A lower level of capital expenditures than those contained in the GLJ Report, or should the assumptions used by the Corporation prove to be inaccurate, the Corporation may be required to pay cash income taxes sooner than anticipated, which will reduce cash flow available to the Corporation.

Internal Controls

Material weaknesses in the Corporation's internal controls may negatively affect the Corporation and the market price of the Common Shares

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement the required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations, or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and harm the trading price of the Common Shares.

Availability of Drilling Equipment and Access

Restrictions on the availability of and access to drilling equipment may impede the Corporation's exploration and development activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's exploration, development, and operating activities.

Forced or Child Labour in Supply Chains

The introduction of new supply chain due diligence and reporting requirements could expose the Corporation to certain risks.

In May 2023 *An Act to enact the Fighting Against Forced Labour and Child Labour in Supply Chains Act and to amend the Customs Tariff* was passed and came into force on January 1, 2024. Pursuant to the new legislation, any company that is subject to the reporting requirements, including the Corporation, is required to conduct certain due diligence on its supply chains and to file an annual report accordingly. While the Corporation is currently unaware of any forced or child labour in any of its supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which the Corporation has a connection, which could negatively impact the reputation of the Corporation. Additionally, due to the fact that the reporting requirements are new and thus there is no existing industry standard, the Corporation is at risk of inadvertently preparing a report that is insufficient.

Pandemics and their Effect on the Global Economy

Pandemics may cause disruptions in economic activity.

In the event of a global pandemic, countries around the world may close international borders and order the closure of institutions and businesses deemed non-essential. This could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas. Any reduction in economic activity in certain countries resulting from outbreaks, government-imposed lockdowns and other restrictions could have a negative effect on demand for oil and natural gas and could aggravate the other risk factors identified herein.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR+ at www.sedarplus.ca. 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 28th day of June, 2024.

(signed) "*Chayan Chakrabarty*" Chayan Chakrabarty President and Chief Executive Officer	(signed) "*Jerrad Blanchard*" Jerrad Blanchard Chief Financial Officer
(signed) "*Brian Moss*" Brian Moss Chair of the Reserves Committee	(signed) "*Robert Steele"* Robert Steele 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, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2024, 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, 2024, 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$)			
			Audited ($MM)	Evaluated ($MM)	Reviewed ($MM)	Total ($MM)
GLJ Ltd.	March 31, 2024	Australia	-	42,058	-	**42,058**

6. In our opinion, the reserves data 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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, June 12, 2024

"Originally Signed By"

Patrick A. Olenick, P. Eng.
Vice President, International Evaluations

SCHEDULE "C"

AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

I. ROLE AND OBJECTIVE

A. 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:

(a) To assist directors of the Corporation (the "**Directors**") on meeting their responsibilities in respect of the review, approval, preparation and disclosure of the financial statements of the Corporation and related documentation;

(b) To provide a communication link between independent Directors and external auditors;

(c) To enhance the external auditor's independence;

(d) To increase the credibility and objectivity of financial reports; and

(e) To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management and external auditors.

II. MEMBERSHIP OF COMMITTEE

A. The Committee shall be comprised of at least three (3) Directors, 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.

B. The Board shall appoint the Chair of the Committee, who shall be an independent Director.

C. All of the members of the Committee shall be "financially literate" (as such term is defined in NI 52-110 and by the Toronto Stock Exchange or other applicable regulatory authority) 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.

III. MANDATE AND RESPONSIBILITIES OF COMMITTEE

A. 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.

B. The Committee will review and obtain reasonable assurance that the risk management, internal control, and information systems are operating effectively to produce accurate, appropriate, and timely management and financial information. This includes:

(a) identify, monitor and mitigate business risks;

(b) ensure compliance with legal, ethical and regulatory requirements;

(c) review the Corporation's risk management controls and policies;

(d) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management and the external auditor;

(e) review management steps to implement and maintain appropriate internal control procedures including a review of policies;

(f) review adequacy of security of information, information systems and recovery plans;

(g) monitor compliance with statutory and regulatory obligations;

(h) review the appointment of the Chief Financial Officer; and

(i) review the adequacy of accounting and finance resources.

C. 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:

(a) 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;

(b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

(c) ascertaining compliance with covenants under loan agreements;

(d) reviewing accounting treatment of unusual or non-recurring transactions;

(e) reviewing disclosure requirements for commitments and contingencies;

(f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

(g) reviewing unresolved differences between management and the external auditors; and

(h) obtaining explanations of significant variances with comparative reporting periods.

D. 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.

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

(a) review and recommend to the Board, for shareholder approval, engagement of the external auditor including, as part of such review and recommendation, an evaluation of the external auditors qualifications, independence and performance;

(b) review and recommend to the Board the annual external audit plan, including but not limited to the following:

(i) engagement letter;

(ii) objectives and scope of the external audit work;

(iii) procedures for quarterly review of financial statements;

(iv) materiality limit;

(v) areas of audit risk;

(vi) staffing;

(vii) timetable; and

(viii) proposed fees;

(c) 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;

(d) 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

(e) 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.

F. Review and advise the Board with respect to the planning, conduct and reporting of the annual audit, including but not limited to:

(a) any difficulties encountered, or restrictions imposed by management during the annual audit;

(b) any significant accounting or financial reporting issue including the resolution of any disagreement between management and the external auditors;

(c) the auditor's evaluation of the Corporation's system of internal controls, procedures and documentation;

(d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weakness; and

(e) assess the performance and consider the annual appointment of external auditors for recommendation to the Board.

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

H. The Committee shall review and receive assurances on the independence of the external auditor.

I. The Committee shall review the non-audit services to be provided by the external auditor's firm and consider the impact on the independence of the external audit.

J. The Committee shall establish a procedure for:

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

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

K. 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.

L. The Committee shall have the authority to communicate directly with the internal auditors of the Corporation (if any) and the external auditors of the Corporation.

M. 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.

N. 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.

O. The Committee shall review material litigation and its impact on financial reporting.

IV. MEETINGS AND ADMINISTRATIVE MATTERS

A. 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.

B. 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.

C. 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.

D. 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.

E. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end 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.

F. The Corporation's auditors shall be advised of the names of the Committee members and, when appropriate, will receive notice of and be invited to attend meetings of the Committee and to be heard at those meetings on matters relating to the auditor's duties.

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

H. 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.

I. 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.

J. 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.

K. 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. Subject to the foregoing, following their appointment as a member of the Committee each member shall hold office until the Committee is reconstituted.

L. 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.

V. STANDARDS OF LIABILITY

Nothing contained in this Mandate and Terms of Reference is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate and Terms of Reference are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

VI. REVIEW OF MANDATE AND TERMS OF REFERENCE

The Committee shall review and assess this Mandate and Terms of Reference annually and otherwise as it deems appropriate and recommend changes to the Board.

Dated: March 28, 2018