International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended
September 30, 2019 and 2018

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Bengal Energy Ltd. ("Bengal" or the "Company") is at and for the three months and six months ended September 30, 2019.

This MD&A dated November 8, 2019 should be read in conjunction with the Company's interim consolidated financial statements and related notes for the quarter ended September 30, 2019. The interim consolidated financial statements of the Company have been prepared in accordance with International Accounting Standards (IAS) 34.

The functional currency of the Company's operating subsidiary is the Australian dollar; the functional currency of the Company is the Canadian dollar ("CAD"). The Company's presentation currency is the CAD. In this MD&A, all dollar amounts are expressed in CAD unless otherwise noted.

This MD&A contains non-IFRS measures, abbreviations and forward-looking information relating to future events and the Company's future performance. Please refer to "Non-IFRS Measurements", "Abbreviations" and "Advisories" sections at the end of this MD&A for further information.

Additional information relating to Bengal, including Bengal's audited March 31, 2019 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended September 30, 2019 may be referred to as "second quarter fiscal 2020", "Q2 fiscal 2020", "Q2 FY 2020", "current quarter", and "the quarter". The comparative three months ended September 30, 2018, may be referred to as "second quarter fiscal 2019", "Q2 FY 2019", and "prior year's quarter".

SECOND QUARTER FISCAL 2020 SUMMARY

Financial Summary:

- **Acquisition** – On September 12, 2019 the Company signed a purchase sales agreement for the previously announced acquisition of a 100% working interest in four Petroleum Leases ("PLs"). All four PLs are located adjacent to the Company's existing gas exploration block ATP 934 in the Cooper Basin. The PLs are all prospective gas assets, along with one oil asset, some of which have produced in the past but all are currently non-producing.
- **Sales Revenue** – Crude oil sales revenue was $2.6 million in the second quarter of fiscal 2020, which is 22% lower than the $3.3 million recorded in Q2 fiscal 2019. Although the Company recorded 14% higher production in the quarter compared to the same quarter last year, an 18% decline in average $US Brent pricing negatively impacted sales revenue quarter over quarter and reduced the value of the Company's inventory.
- **Hedging** – The Company's credit facility requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. During the current quarter, forward fixed-price contracts were placed on 50% of Q2 fiscal 2021 estimated production for July 2020 at US$56.64/bbl, August 2020 at US$56.46/bbl and September 2020 at US$56.32/bbl.
- **Cash from Operations** – Bengal generated cash from operations of $0.5 million during Q2 fiscal 2020 compared to $0.6 million of cash from operations in Q2 fiscal 2019. The primary reason for the decrease in cash from operations during Q2 fiscal 2020 as compared to Q2 fiscal 2019 was lower oil prices in Q2 fiscal 2020.
- **Net Loss** – Bengal reported a net loss of $0.5 million for the current quarter compared to a net loss of $0.7 million in the second quarter of fiscal 2019. The primary driver for the net loss for Q2 fiscal 2020 was the lower oil prices offset by higher production volumes.
- **Adjusted Net Income** – Bengal reported adjusted net income of $0.2 million for the current quarter and adjusted net income of $0.4 million for Q2 fiscal 2019. Net income is adjusted for unrealized gain (loss) on financial instruments, the unrealized foreign exchange gain (loss) for the period and the non-cash impairment of non-current assets.
- **Bank Debt Reclassification –** On November 5, 2019, Westpac and the Company executed an agreement to extend the maturity date of the Company's bank debt of US $12.5 million to October 31, 2020.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 30,667 bbls, which is a 14% increase from the 26,870 bbls produced in the second quarter of fiscal 2019. The current quarter production averaged 333 bbls/day compared to 292 bbls /day produced in the second quarter of fiscal 2019. The increase in production is a result of the completion of the development program which saw five wells drilled beginning in Q4 fiscal 2019.
- **Capital Expenditures** – Bengal incurred $0.5 million in capital expenditures during Q2 fiscal 2020. This investment went towards the completion of the five-well drilling program commenced in Q4 fiscal 2019 and the frac completion program of wells C15 and C21

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

Bengal's producing and non-producing assets are situated in Australia's Cooper Basin, a region featuring large accumulations of very light and high quality crude oil and natural gas. The Company's core Australian assets, Barrolka, Cuisinier, Tookoonooka, ATP 934 and four recently acquired petroleum licenses are situated within an area of the Cooper Basin that is well served with production infrastructure and take-away capacity for produced crude oil and natural gas. Still in early stages in terms of appraisal and development, Bengal believes these assets offer attractive upside potential for both oil and gas. Australia presents a stable political, fiscal and economic environment in which to operate, and a favourable royalty regime for oil and gas production.

Under the State of Queensland Regulatory process, ATPs (Authority to Prospect) are granted by the State generally for a period of twelve years with one third of the original grant area expiring every four years. At the end of the final term of the ATP, an application can be made to continue a portion of the permit in the form of a PCA (Potential Commercial Area). PCAs have a life span of five to fifteen years. If a discovery of oil or gas is made, an application for a PL (Petroleum Lease) is made to allow for production. PLs are granted for up to a thirty-year term. Bengal now has two PLs in the Cuisinier field, PL 303 and PL 1028. This is in addition to the four PLs acquired in Q2 FY 2020.

AUSTRALIA – Cooper Basin, Queensland

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

The Cuisinier 29 well is on production from the newly discovered DC-50 zone. A development plan for this new zone is under preparation with further drilling and evaluation expected in Q1 calendar 2020.

Planning and drilling location selection is underway for the next multi-well development and appraisal drilling campaign which is expected to commence late in the second quarter of calendar 2020.

A pilot reservoir pressure maintenance scheme, is planned to commence during the first quarter of calendar 2020. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier-24 well. The broad nature of the Cuisinier structure combined with variable flank aquifer pressure support has resulted in pressure depletion within the central portion of the Cuisinier pool. The injection of produced formation water is anticipated to increase production in up to four offsetting wells. In addition, the program will also complement future water flood expansion phases currently in the initial planning stages.

Wompi Block (Controlling permit ATP 752) (38.08% WI)

The Company and its joint venture partners are planning to conduct an extended production test on the Nubba gas discovery well during Q4 calendar 2019 with plans to pipeline connect the well for production subject to commercial flow rates and gas reserves being achieved.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned liquids-rich natural gas exploration block. In order to mitigate both financial and development risk, Bengal has done extensive state of the art geophysical work that has not been widely applied in Australia and which gives us a higher degree of confidence in the block and focuses our attention on the most likely prospects.

Discussions are being held with third parties who may have an interest in farming in on this block, supporting the next phase of exploration thereby further de-risking the natural gas potential of the permit.

PL 114 Wareena, PL 157 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% W.I.)

As announced in the Bengal press release of September 12, 2019, the Company has executed a binding purchase sales agreement to acquire a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market (collectively, the "Assets"). These non-productive PLs are highly compatible with and in close proximity to ATP 934. Receipt of all required regulatory approvals is expected to occur early in the second quarter of calendar 2020 to complete the acquisition. Bengal continues to integrate subsurface data from the PLs to enhance the Company's understanding of ATP 934 and to finalize the selection of exploration and appraisal drilling locations.

Included in this program is an oil zone completion in a cased well which recovered 588 bbls/d of 37 degree API oil, based on a 105-minute test period when it was drilled in 2007. Upon completion of a successful test, this well will be immediately equipped for production and the oil sold into the regional market. The Company is in discussions with potential industry and financial partners to fund this activity.

The 100% ownership of these Assets presents an appraisal and development opportunity that will be operated by the Company and is seen to be not only complementary to our proven producing, non-operated Cuisinier asset, but also as a key stepping stone for Bengal's natural gas platform upon which future exploration growth through ATP 934 can be undertaken.

Transaction Details

In exchange for 100% interest in the Assets, Bengal accepts 100% of the cost of the future abandonment and reclamation liabilities (undiscounted internal estimate of AUS $1.7 million) associated with the Assets and the reservation of a modest non-convertible gross overriding royalty on future oil or gas production from the Assets payable to the vendors, plus transaction costs of $0.15 million.

Synergies with ATP 934 Exploration Program

This acquisition supports Bengal's strategy to maximize its ownership and operatorship of its permits in the Cooper Basin of Australia. Bengal is currently examining funding alternatives to evaluate the new PLs and to drill up to three wells in calendar 2020.

ATP 934 covers an area of 1,462 km^2 (360,000 acres) and is immediately surrounded by the newly acquired PLs that are subject to regulatory approval. Bengal has identified and mapped six individual drilling prospects on the ATP 934 permit, some of which are directly offsetting the cased wells located on the PLs.

ATP 732 – Tookoonooka (100% W.I.)

The Company was successful in its application to the state regulator for a later work program for the final 4-year term of this tenement which runs to March 2023. This work program is designed to evaluate both oil and natural gas accumulations on the northern and south western flanks of the block.

OPERATING SUMMARY

($000s except per share, %, volumes and netback amounts)	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Oil revenue	$ 2,576	$ 3,315	$ 4,538	$ 6,530
Operating netback[(1)]	$ 1,649	$ 1,601	$ 2,761	$ 3,214
Cash flow from operations	$ 527	$ 603	$ 843	$ 1,622
Funds from operations[(2)]	$ 724	$ 750	$ 711	$ 1,625
Per share ($) (basic and diluted)	$ 0.01	$ 0.01	$ 0.01	$ 0.02
Net loss	$ (506)	$ (728)	$ (1,256)	$ (1,214)
Per share ($) (basic and diluted)	$ (0.00)	$ (0.01)	$ (0.01)	$ (0.01)
Adjusted net income (loss)[(3)]	$ 177	$ 350	$ (308)	$ 777
Per share ($) (basic and diluted)	$ 0.00	$ 0.00	$ 0.00	$ 0.01
Capital expenditures	$ 477	$ 1,274	$ 1,757	$ 1,575
Oil volumes (bbls/d)	333	292	292	305
Netback[(1)]($/bbl)	$ 53.78	$ 59.58	$ 51.74	$ 57.59

(1) Operating netback is a non-IFRS measure and includes realized gain (loss) on financial instruments. Operating netback per bbl is calculated by dividing revenue (including realized gain (loss) on financial instruments) less royalties and operating costs by the total production of the Company measured in bbls. A reconciliation of the measures can be found on page 7.
(2) Funds from operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year-to-date. Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed. A reconciliation of the measures can be found in the table on page 18.
(3) Adjusted net income (loss) and adjusted net income (loss) per share are non-IFRS measures. The comparable IFRS measure is net income (loss). A reconciliation of the two measures can be found in the table on page 18.
(4) The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

RESULTS OF OPERATIONS

Production	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Oil production (bbls/d)	333	292	292	305
Oil production (bbls)	30,667	26,870	53,355	55,808

Revenue/Pricing

The following table outlines the oil lifting from bills of lading, pipeline oil estimates, applicable prices and oil sales reflected in the Company's financials:

		Three months ended September 30		Six months ended September 30	
		2019	2018	2019	2018
	Oil lifting				
	Volume (000s bbls)	24.6	29.4	48.9	66.3
	Weighted average price (US$/bbl)	65.53	80.54	54.31	58.27
	Sales (US$000's)	1,612	2,368	2,656	3,863
A.	Sales ($000's)	2,208	3,410	4,504	7,216
	Pipeline oil				
	Volume (000s bbls), change	6.0	(2.5)	4.4	(10.5)
	Price (US$/bbl), change	(7.52)	7.26	(15.99)	13.94
	Net sales (US$000's)	266	(70)	15	(503)
B.	Net sales ($000's)	368	(95)	34	(686)
A.+B.	Total oil sales ($000s)	2,576	3,315	4,538	6,530

The price received for Bengal's Australian oil sales is benchmarked on US$ Brent for the month in which the bill of lading occurs, plus a realized premium due to oil quality differences. Pipeline oil is the term used to describe oil moving along the pipeline from the wellhead to the port that has been legally transferred to the buyer but not priced and waiting to be sold. Lifting occurs when the oil is moved from the port to the ship.

Realized crude oil price during Q2 fiscal 2020 was significantly impacted by the decline in US Brent as compared to Q2 fiscal 2019. The realized weighted average price of oil lifting sales was US$65.53/bbl for Q2 fiscal 2020 as compared to US$80.54/bbl for Q2 FY 2019. When combined with lower oil lifting volumes in Q2 fiscal 2020 of 24.6K bbls as compared to 29.4K bbls in Q2 fiscal 2019, oil lifting sales were lower at $2.2 million for the current quarter as compared to $3.4 million for Q2 fiscal 2019. During the current quarter, the value of the pipeline oil increased by $0.4 million due to a combination of an increase in oil pipeline volume of 6,014 bbls (14,822 bbls at the beginning of the quarter up to 20,836 at the end of the quarter) and a reduction in pipeline oil valuation of US$7.52/bbl. When oil lifting sales are adjusted for the change in value of the pipeline oil for the current quarter of $0.4 million, Bengal's total oil sales are $2.6 million for the current quarter as compared to $3.3 million for Q2 fiscal 2019.

The following table outlines average benchmark prices:

	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Brent oil ($/bbl)	81.75	98.28	87.02	97.22
Brent oil (US$/bbl)	61.93	75.22	65.43	74.86
Number of CAD$ for 1 AUS$	0.90	0.98	0.92	0.97
Number of CAD$ for 1 US$	1.32	1.29	1.33	1.30

($000s)

Netbacks

	Three months ended September 30		Six months ended September 30	
	2019	**2018**	**2019**	**2018**
Oil sales	2,576	3,315	4,538	6,530
Realized gain (loss) on financial instruments	253	(430)	347	(845)
Royalties	147	273	248	391
Operating expenses	1,033	1,011	1,876	2,080
Netback	1,649	1,601	2,761	3,214
($/bbl)				
Oil sales	84.00	123.37	85.05	117.01
Realized gain (loss) on financial instruments	8.25	(16.00)	6.50	(15.14)
Royalties	4.79	10.16	4.65	7.01
Operating expenses	33.68	37.63	35.16	37.27
Netback	53.78	59.58	51.74	57.59

Operating netbacks in Q2 fiscal 2020 were $1.6 million or $53.78/bbl compared to Q2 fiscal 2019 at $1.6 million or $59.58/bbl. For the six months ended Q2 fiscal 2020, operating netback was $2.8 million or $51.74/bbl. This compares to $3.2 million or $57.59/bbl for the six months ended Q2 fiscal 2019. Operating expenses for the current quarter were $33.68/bbl as compared to $37.63/bbl for Q2 fiscal 2019. Bengal had a realized gain on financial instruments of $0.3 million due to the approximate US$75/bbl hedges throughout the three months ended Q2 fiscal 2020. Royalty rates came in at 6% of oil sales for Q2 fiscal 2020 or $4.79/bbl as compared to 8% of oil sales or $10.16/bbl for Q2 fiscal 2019.

Risk Management Activities

Bengal has entered into financial commodity contracts as part of its risk management program to manage commodity price fluctuations related to its primary producing assets being the Cuisinier field in Australia's Cooper Basin. It is a requirement under Bengal's Credit Facility to hedge 50% of its annual production.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its crude oil financial contracts on the statement of financial position at each reporting period, with the change in fair value being classified as unrealized gains and losses in the consolidated statement of income (loss).

As at September 30, 2019, the Company has the following derivative contracts:

Time period	**Type of contract**	**Quantity Contracted (bbls)**	**Price floor US$/bbl**	**Price ceiling US$/bbl**
October 1, 2019 – December 31, 2019	Oil - swap	7,500	54.20	54.20
October 1, 2019 – December 31, 2019	Oil – put option	7,500	54.20	-

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(60)	8	(52)
Non-current fair value of financial instruments	-	-	-
	(60)	8	(52)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
January 1, 2020 – March 31, 2020	Oil - swap	15,000	63.74	63.74

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	101	-	101
Non-current fair value of financial instruments	-	-	-
	101	-	101

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
April 1, 2020 – April 30, 2020	Oil - swap	5,000	59.49	59.49

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	9	-	9
Non-current fair value of financial instruments	-	-	-
	9	-	9

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
May 1, 2020 – May 31, 2020	Oil - swap	5,000	59.27	59.27

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	9	-	9
Non-current fair value of financial instruments	-	-	-
	9	-	9

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
June 1, 2020 – June 30, 2020	Oil - swap	5,000	59.08	59.08

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	9	-	9
Non-current fair value of financial instruments	-	-	-
	9	-	9

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
July 1, 2020 – July 31, 2020	Oil - swap	5,000	56.64	56.64

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(6)	-	(6)
Non-current fair value of financial instruments	-	-	-
	(6)	-	(6)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
August 1, 2020 – August 31, 2020	Oil - swap	5,000	56.46	56.46

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(6)	-	(6)
Non-current fair value of financial instruments	-	-	-
	(6)	-	(6)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
September 1, 2020 – September 30, 2020	Oil - swap	5,000	56.32	56.32

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(6)	-	(6)
Non-current fair value of financial instruments	-	-	-
	(6)	-	(6)

Total

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	50	8	58
Non-current fair value of financial instruments	-	-	-
	50	8	58

The fair value of the financial contracts outstanding as at September 30, 2019 is $0.1 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period, having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the six months ended September 30, 2019, the derivative commodity contracts resulted in a realized gain of $0.4 million (September 30, 2018 – loss of $0.8 million) and an unrealized loss of $.01 million (September 30, 2018 – loss of $0.1 million).

Royalties

Royalties

	Three months ended September 30		Six months ended September 30	
	2019	**2018**	**2019**	**2018**
Royalty expense ($000s)	147	273	248	391
$/bbl	4.79	10.16	4.65	7.01
% of revenue	6	8	5	6

During the current quarter, the Queensland Government increased oil royalties from 10% to 11.25%. The royalty rate is applied to gross revenues after deducting for allowable capital, transportation and operating costs.

Royalty rates came in at 6% of oil sales for Q2 fiscal 2020 or $4.79 per bbl as compared to 8% of oil sales or $10.16/ bbl for Q2 fiscal 2019. The lower royalty expense per barrel is due to an increased level of capital expenditure during the current quarter which is deductible against the royalty calculation.

Operating Expenses

($000s)
Operating expenses

	Three months ended September 30		Six months ended September 30	
	2019	**2018**	**2019**	**2018**
Production	126	187	278	370
Transportation	907	824	1,598	1,710
	1,033	1,011	1,876	2,080
Production - $/bbl	4.11	6.96	5.21	6.63
Transportation - $/bbl	29.58	30.67	29.95	30.64
	33.69	37.63	35.16	37.27

Total operating expense during the second quarter fiscal 2020 was $1.0 million or $33.69/bbl. This compares to $1.0 million of operating expenses for the second quarter fiscal 2019 or $37.63/bbl. Operating expenses per barrel were lower in the current quarter due to lower field production costs as compared to Q2 fiscal 2019. The Company anticipates ongoing operating expenses to be in the $33-35/bbl range.

General and Administrative (G&A) Expenses

($000s)
G&A

	Three months ended September 30		Six months ended September 30	
	2019	**2018**	**2019**	**2018**
Total G&A	879	765	1,831	1,315
Capitalized G&A	(157)	(25)	(178)	(156)
Net G&A	722	740	1,653	1,408

Total G&A expense for Q2 fiscal 2020 was $0.9 million as compared to $0.8 million for Q2 fiscal 2019. Total G&A expenditures were moderately higher due to increased legal and consulting costs as a result of the Company's acquisition of the PLs. Net G&A for Q2 fiscal 2020 and Q2 fiscal 2019 was $0.7 million. The capitalized G&A value for Q2 fiscal 2020 is primarily due to legal and third-party costs associated with the acquisition of the PLs.

Share-based Compensation ("SBC")

($000s) **SBC**	**Three months ended September 30**		**Six months ended September 30**	
	2019	**2018**	**2019**	**2018**
Expensed share-based compensation	6	13	17	43
Capitalized share-based compensation	-	2	1	6
	6	15	18	49

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

Depletion and Depreciation (DD&A)

($000s) **DD&A**	**Three months ended September 30**		**Six months ended September 30**	
	2019	**2018**	**2019**	**2018**
Petroleum and natural gas properties	442	346	782	724
Other assets	1	3	3	6
Right-of-use assets	12	-	24	-
	455	349	809	730
Petroleum and natural gas properties - $/bbl	14.41	12.88	14.66	12.97

Production in Q2 fiscal 2020 was 30,667 bbls compared with 26,870 bbls in Q2 fiscal 2019. The higher production in Q2 fiscal 2020 when compared to Q2 fiscal 2019 resulted in higher depletion expense.

Impairment Expense

($000s) **Impairment expense**	**Three months ended September 30**		**Six months ended September 30**	
	2019	**2018**	**2019**	**2018**
Exploration and evaluation assets	-	810	10	955
Petroleum and natural gas properties	-	-	10	-
	-	810	20	955

During Q2 fiscal 2020, the Company did not take any impairment charges.

Finance Expense

($000s) Finance expense	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Interest income	-	(1)	(1)	(8)
Accretion expense on decommissioning and restoration liability	8	10	17	20
Letter of credit charges	-	-	-	8
Interest on lease liability	3	-	7	
Interest on credit facility	322	249	623	492
	333	258	646	512

Interest on the Credit Facility is calculated as US LIBOR plus a margin of 3.75%, compared with US LIBOR plus 3.2% during 2018.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Geological and geophysical	78	34	138	171
Drilling	14	777	148	860
Completions	233	463	1,319	544
Acquisition	152	-	152	-
	477	1,274	1,757	1,575
Exploration and evaluation expenditures	-	752	10	912
Development and production expenditures	477	522	1,747	663
	477	1,274	1,757	1,575

Capital expenditures of $0.3 million in Q2 fiscal 2020 (geological and geophysical, drilling and completions) relates to the completion of the five-well 2019 drilling program. Acquisition costs of $0.2 million relates to the acquisition of the new PLs.

CREDIT FACILITY

On May 29, 2019, the Company and Westpac entered into an amendment to its reserved based revolving credit facility (the "Credit Facility") that had principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment have transferred directly to the May 29, 2019 amendment. The Credit Facility requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. The interest rate under the Credit Facility remained unchanged at US LIBOR plus 3.75%.

On November 5, 2019, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to October 31, 2020. All previous terms and conditions remain the same except for the interest rate which moved from 3.75% to 3.95%.

Management continues to discuss with the lender the opportunity to lengthen the term of the current facility particularly in light of the recent acquisition which has the potential to both increase reserves and improve cash flow. There would be an adverse impact on the Company's liquidity should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility.

The Credit Facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the Credit Facility. The Company was in compliance with the stated covenants at September 30, 2019.

The table below indicates the payment schedule for the Credit Facility:

(US$000s)	
Credit Facility	
Fiscal year 2021	12,369

Subsequent to the Balance Sheet date, the Company and Westpac have agreed to amend the maturity date of the Credit Facility from April 1, 2020 to October 31, 2020.

SHARE CAPITAL

Trading history	**Three months ended September 30**		**Six months ended September 30**	
	2019	**2018**	**2019**	**2018**
High ($)	0.11	0.16	0.13	0.18
Low ($)	0.07	0.09	0.06	0.09
Close ($)	0.09	0.09	0.09	0.09
Volume (000s)	975	1,977	1,761	4,737
Shares outstanding (000s)	102,267	102,267	102,267	102,267
Weighted average shares outstanding (000s) - basic and diluted	102,267	102,267	102,267	102,267

At November 08, 2019, there were 102,266,694 common shares issued and outstanding, together with 3,488,326 outstanding options.

LIQUIDITY RISK AND CAPITAL RESOURCES

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of trade and other payables, lease liability and credit facility, amounting to $18.4 million at September 30, 2019 (March 31, 2019 - $19.1 million).

At September 30, 2019, the Company had a working capital deficiency of $14.1 million, including cash and short-term deposits of $1.2 million and restricted cash of $0.1 million, compared to a working capital deficiency of $12.7 million at March 31, 2019. The working capital deficiencies are primarily a result of the reclassification of the bank debt of $16.5 million to current from long term. The Company does not anticipate any difficulty in meeting its current obligations as the Company has generated positive working capital and is forecasted to continue to generate positive working capital. The Company has no available undrawn debt capacity under its Westpac Credit Facility. Subsequent to September 30, 2019, the Company extended the maturity date of the credit facility that is classified as a current liability at September 30, 2019 to October 31, 2020.

The Company has significant spending commitments to be incurred by February 2021 on ATP 934 and has its US$12.4 million Credit Facility that now matures in October 2020. There can be no guarantees that alternative forms of capital raising will be available or obtained on terms that are satisfactory to the Company. Should Westpac not further defer principal payments and the Company be unsuccessful in obtaining additional funding, there will be an adverse impact to the Company's liquidity.

The majority of the Company's oil sales are benchmarked on US$ Brent prices, which averaged US$65.43/bbl for the six months ended September 30, 2019. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of lower crude prices, the Company is acting with its Joint Venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where practical and appropriate. The Company intends to use a combination of internally generated sources of cash and externally generated sources of cash, such as farm-outs and alternative financing sources to fund its exploration and development activities through fiscal 2020 and beyond.

COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 2015. The Company acquired an additional 21.43% working interest and received ministerial approval for the acquisition on August 11, 2015. In Q4 FY 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS$0.3 million cash and potential future cash payments of up to AUS$1.0 million, which is made up of AUS$0.2 million on certification by an independent competent person appointed by the buyer of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of first commercial gas to market. The work program consists of 260 km^2 of 3D seismic and up to three wells.

AFE commitments are reflected where the Company has agreed with Joint Venture partners to proceed with activities (e.g. onshore Australia, Barta Block Cuisinier PL 303). The costs of these activities are based on minimum work budgets included in bid documents and agreements among Joint Venture parties, and have not been provided for in the financial statements. Actual costs may vary from budget. See Liquidity Risk and Capital Resources above.

At September 30, 2019, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2021	12.6
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at September 30, 2019 at an exchange rate of AUS$1.00 = CAD$ 0.8940.

At September 30, 2019, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations October 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	660	155	311	194	-
Decommissioning and restoration	3,402	-	535	-	2,867
	4,062	155	846	194	2,867

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	**Sep 30 2019 Q2 2020**	June 30 2019 Q1 2020	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2019	Mar 31 2018 Q4 2018	Dec 31 2017 Q3 2018
Oil sales	2,576	1,962	2,667	2,014	3,315	3,215	2,783	3,211
Cash flow from operations	527	316	635	434	603	1,019	858	431
Funds from (used in) operations(1)	724	(13)	842	(247)	750	875	525	1,268
Per share – basic and diluted ($)	0.01	0.00	0.01	0.00	0.01	0.01	0.01	0.01
Net (loss) income	(506)	(750)	(2,144)	883	(728)	(486)	(12,526)	206
Per share – basic and diluted ($)	(0.00)	(0.01)	(0.02)	0.01	(0.01)	0.00	(0.12)	0.00
Capital expenditures	477	1,280	2,473	298	1,274	301	939	342
Working capital (deficiency)	(14,120)	(13,964)	(12,740)	6,331	(3,353)	(2,915)	3,385	(637)
Total assets	40,849	40,373	42,489	44,291	43,547	44,867	45,714	56,932
Shares outstanding (000s)	102,267	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	333	249	281	300	292	318	334	354
Netback(1) ($/bbl)	53.78	49.01	76.82	22.54	59.58	55.69	42.66	63.13

(1) See “Non-IFRS Measurements” on page 18 of this MD&A.

Oil sales and production over the last eight quarters peaked during the second quarter of fiscal 2018 (calendar Q3 2017) as all wells from the Company's 2014 and 2016 drilling campaign were on stream. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since the peak in the second quarter of fiscal 2018. A significant decline in $US Brent prices during Q3 fiscal 2019 was responsible for the low oil sales and funds from operations. The Company began a five well drilling program in Q4 fiscal 2019 that was completed in Q1 fiscal 2020. The increase in oil volumes in the current quarter of 333 bbls/d are the result of the 5 well drilling program.

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at September 30, 2019 due to the material weaknesses noted below.

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

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

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

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

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

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates, which are reviewed on an ongoing basis. A full discussion of the Company's critical judgments and accounting estimates is included in its 2019 annual Management's Discussion and Analysis dated June 20, 2019.

NEW ACCOUNTING STANDARDS

Effective April 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in net income (loss) and comprehensive income (loss) in the consolidated statements of comprehensive income (loss). IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $249,933 increase to right-of-use assets (Note 6), with a corresponding increase to lease liability (Note 9). There was an adjustment of $ 31,232 for lease incentives previously received.

On adoption of IFRS 16, the Company's lease liability related to contracts classified as leases are measured at the discounted present value of the remaining minimum lease payments, excluding short-term and low-value leases. The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations. The weighted average incremental borrowing rate used to determine the lease liability at adoption was approximately 6.0%. The right-of-use asset and lease liability recognized relate to the Company's head office lease in Calgary.

Upon the adoption of IFRS 16, the Company adopted the following significant accounting policy effective April 1, 2019:

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease liability is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received, retirement costs and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term. Interest expense is recognized on the lease liability using the effective interest rate method and payments are applied against the lease liability.

Key areas where management has made judgments, estimates and assumptions related to the application of IFRS 16 include:

- The incremental borrowing rate is based on judgments including economic environment, term, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease liability and the resulting interest expense and depreciation expense, may differ due to changes in the market conditions and lease term.
- Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

IFRS 3

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. The changes clarify the minimum requirements to be a business, assess whether an acquired process is substantive, narrow the definition of outputs and implement an optional concentration test. The amendments to IFRS 3 are effective for annual reporting periods beginning on or after 1 January 2020 and apply prospectively and early application is permitted. Effective July 1, 2019, the Company applied the amendment.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netbacks, netbacks per share, funds from operations, funds from operations per share, adjusted net income and adjusted net income per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Netback per barrel equals netback divided by the applicable number of barrels. Management utilizes these measures for operational performance. Funds from operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed Adjusted net income is a non-IFRS measure, which should not be considered an alternative to “Net income (loss)” as presented in the consolidated statement of income (loss) and comprehensive income (loss), and is presented in the Company’s financial reports to assist management and investors in analyzing financial performance net of gains and losses outside of management’s immediate control. Adjusted net income equals net income (loss) less unrealized gain (losses) on foreign exchange and unrealized gain (losses) on financial instruments plus non-cash impairment of non-current assets. Adjusted net income per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

Management believes the presentation of the non-IFRS measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

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

($000s)	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Cash from operating activities	527	603	843	1,622
Changes in non-cash working capital	197	147	(132)	3
Funds from operations	724	750	711	1,625

The following table reconciles net income (loss) to adjusted net income (loss), which is used in this MD&A:

($000s)	Three months ended September 30		Six months ended September 30	
	2019	2018	2019	2018
Net loss	(506)	(728)	(1,256)	(1,214)
Unrealized loss (gain) on financial instruments	38	(161)	113	19
Unrealized foreign exchange loss	645	429	815	1,017
Non-cash impairment of non-current assets	-	810	20	955
Adjusted net income (loss)	177	350	(308)	777

ABBREVIATIONS

The following abbreviations used in this MD&A have the meanings set forth below:

bbl	-	barrel
bbls	-	barrels
bbls/d	-	barrels per day
$/bbl	-	dollars per barrel
bopd		barrels of oil per day
FY	-	fiscal year
K	-	thousand
km	-	kilometres
km^2	-	square kilometres
Q1	-	three months ended June 30
Q2	-	three months ended September 30
Q3	-	three months ended December 31
Q4	-	three months ended March 31
WI	-	working interest

RISK FACTORS

There are a number of risk factors facing companies that participate in the oil and gas industry. A complete list of risk factors are provided in Bengal's Annual Information Form dated July 2, 2019 filed on SEDAR at www.sedar.com.

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 Bengal wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal's capital program.

An investment in the shares of the Company should be considered speculative due to the nature of the Company's involvement in the exploration for and the acquisition, development and production of oil and natural gas in foreign countries, and its current stage of development. An investor should consider carefully the risk factors set out in the annual information form and consider all other information contained herein and in the Company's other public filings before making an investment decision. Additional risks and uncertainties not currently known to the management of the Company may also have an adverse effect on Bengal's business and the information set out in the annual information form does not purport to be an exhaustive summary of the risks affecting Bengal.

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd., Suite 2000, 715 5th Avenue SW., Calgary, Alberta T2P 2X6, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

Forward-looking Statements - *Certain statements contained within this MD&A constitute forward-looking statements or information ("forward-looking statements") as defined by applicable securities laws. These statements relate to future events or Bengal's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. The projections, estimates and beliefs contained in such forward-looking statements are based on management's estimates, opinions, and assumptions at the time the statements were made, including assumptions relating to: the impact of economic conditions in North America and Australia and globally; industry conditions; changes in laws and regulations including, without limitation, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the availability of qualified operating or management personnel; fluctuations in commodity prices, foreign exchange or*

interest rates; stock market volatility and fluctuations in market valuations of companies with respect to announced transactions and the final valuations thereof; results of exploration and testing activities; and the ability to obtain required approvals and extensions from regulatory authorities.
In particular, this MD&A contains forward-looking statements pertaining to the following:

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Bengal's development programs and the timing and anticipates results thereof;*
- *The anticipated timing and results of a pilot reservoir maintenance scheme at ATP 752;*
- *The timing and nature of a production test at the Wompi Block including subsequent actions that may be taken depending on the results thereof;*
- *The receipt of regulatory approval in respect of the Assets, the anticipated results and characteristics of the Assets and development plans in respect therewith;*
- *Anticipated abandonment and reclamation liabilities of the Assets;*
- *Anticipated funding requirements and sources for the Company's development program; and*
- *Discussions with the Company's lenders, the results thereof and the impact on the Company if it is unable to negotiate an amendment and deferral of principal payment on the Credit Facilities.*

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause Bengal's actual results, performance or achievement to differ materially from those expectations expressed in, or implied by, these forward-looking statements, including but not limited to, risks associated with:

- *Fluctuations in commodity prices, foreign exchange or interest rates;*
- *Changes in the demand for or supply of Bengal's products;*
- *Liabilities inherent in oil and natural gas operations;*
- *The failure to obtain required regulatory approvals or extensions;*
- *The failure to satisfy the conditions under farm-in and joint venture agreements;*
- *The failure to secure required equipment and personnel;*
- *Changes in general global economic conditions including, without limitations, the economic conditions in North America and Australia;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Increased competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *The availability of qualified operating or management personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Inability to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Bengal's development and exploration opportunities;*
- *The results of exploration and development drilling and related activities;*
- *Changes in laws and regulations including, without limitation, the adoption of new environmental, royalty and tax laws and regulations and changes in how they are interpreted and enforced;*
- *The ability to access sufficient capital from internal and external sources; and*
- *Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.*

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

Disclosure of Oil and Gas Information

This document discloses unbooked drilling locations. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Matthew Moorman, Chief Financial Officer
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG