



PRESIDENT'S MESSAGE

The financial performance for the first quarter of 2011 reflects natural gas prices that remained challenged during the quarter. In addition to low natural gas prices, a large number of wells were shut-in for routine work-overs. Notwithstanding the conditions, Emerald Bay continued to cautiously move forward with pipeline and facilities operations in Central Alberta, and well optimization efforts in Medina County Texas.

Q1 2011 Highlights

- ◆ Closed an initial tranche of a private placement with 7,503,701 units at a price of \$0.05 per unit, for aggregate consideration of \$375,185.05.
- ◆ Acquired 100% of the J.N. Wilson A lease from Flinthill Energy, a private, Texas-based oil company. Under the terms of the purchase agreement, the Corporation will issue, subject to the final approval of the TSX Venture Exchange, 532,812 common shares (at \$0.08 per share for aggregate proceeds of \$42,625.00) of the Corporation. The strategic 200 acre parcel has a 78% Net Revenue Interest lease that is held by approximately 2 barrels a day of oil production.
- ◆ Pipeline construction operations for natural gas production was initiated and subsequently completed at Lacombe, Chigwell, and Elnora Alberta.
- ◆ Through its 25% ownership of Production Resources Inc. (PRI), two phases of optimization were completed during the quarter; (1) the work-over of the Olmos zone in the existing wells; and (2) the perforation and production of the by-passed pay zone called the Escondido. Under Emerald Bay's direction, PRI has recently tested one well on the Escondido zone with great success. The Olmos zone was isolated; then the Escondido was perforated and put on pump with no stimulation needed. The initial 24-hour test produced 100% oil at rates equivalent to the Company's stimulated Olmos wells. The business model of PRI was re-invest the monthly revenue into building a reserve base and acquiring the necessary production equipment to make the Taylor-Ina property a valuable income producing asset for many years. Based on the 2010 Year-end Reserve Evaluation at a discount to future net cash flow of 10%, The PRI asset has increased over 130% in value since its acquisition in April of 2010. This also does not include the equipment value and the recent discovery of the Escondido zone at Taylor-Ina.

2011 Growth Potential:

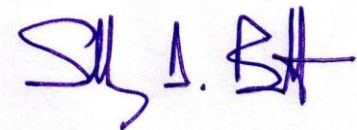
- ◆ Well optimization efforts continue at the Company's oil producing properties in Medina and Atascosa Counties. Five wells were selected for a pilot re-stimulation program targeting a zone that has been producing for approximately 25+ years, but shows signs of near-wellbore damage created by fines migration over several years. The Company is very encouraged by the early results with production volume increases in excess of 150%. We will continue to monitor and test each well during the month of June to assess any volume decline before proceeding with the next phase to re-stimulate 15+ wells. Based on these results we would then roll this out to the remaining 125+ wells in the Taylor-Ina field.
- ◆ Drilling permits are approved on the JN Wilson "B" lease for the summer drilling program at Taylor-Ina. It is expected that drilling operations on the seven wells will take place during the summer and fall of this year.
- ◆ Mineral leasing operations continue for the Company in Medina, Atascosa, Frio, and Guadalupe Counties as Emerald Bay's development focus transitions to liquids rich opportunities in Texas

- ◆ At Joffre, Alberta, work continues on two sections of land where three wells (.50 net) were drilled, cased, cemented and in various stages of completion and tie-in. 02/03-21-39-25 W4 is now tied-in and producing natural gas from the Edmonton Sands. 16-21-39-25 W4 is currently awaiting tie-in this summer. 16-8-39-25 W4 is perforated, tied-in and flowing gas from the Edmonton Sands, and Horseshoe Canyon Coals.
- ◆ At Chigwell, Alberta, two wells (.47 net) in two separate sections are now producing. 02/14-19-41-24 W4 was drilled as part of the 2010 drilling program. It was completed in the Belly River Sand. The pipeline and facilities work is complete and flowing into a sales line. Recent workover at 5-31-42-25 W4 is now complete in the Glauconitic and is now producing.
- ◆ At Elnora, Alberta, one well, 13-9-34-23 W4 (.17 net) pipeline and facilities operations are underway and expected to be completed by the second week of July.
- ◆ At Bittern Lake Alberta, one well, 12-21-46-22 W4 (.25 net) Pipeline and facilities operations are planned during the month of July.
- ◆ At Gilby, Alberta, The Company has two wells (.43 net) on two separate sections in various stages of development. The wells will be producing from the Ellerslie, Glauconitic, and Viking. 16-26-40-1 W5 is expected to complete pipeline and facilities operations by the end August.
- ◆ At Lacombe, Alberta, three wells (.67 net) Weather permitting, perforation and stimulation operations are anticipated to begin by the end of June at 16-17-41-26 W4. 13-27-41-26 W4 has been perforated and is currently producing without, and prior to stimulation. Completion and tie-in operations are scheduled for this summer at 8-21-41-26 W4.

In Closing

We will continue to pursue a carefully designed capital expenditure program, including acquisitions and dispositions, which would allow us to add production, reserves and cash flow in a cost effective manner while maintaining a level of flexibility in our balance sheet. We are confident that we have prepared ourselves to emerge from this environment operationally strong, and we expect to be well positioned to respond quickly when the business environment improves. Our proven management and dedicated team of professionals are engaged and committed to developing our high-quality asset base

Best Regards,

A handwritten signature in blue ink, appearing to read 'Shelby Beattie', is written over a light blue rectangular background.

Shelby Beattie, President and Chief Executive Officer

MANAGEMENT'S DISCUSSION & ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with Emerald Bay Energy Inc. ("EBY" or the "Company") unaudited interim financial statements for the three months ended March 31, 2011 and the MD&A and the audited financial statements for the year ended, December 31, 2010. Certain information regarding EBY contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

Additional information relating to the Company is available on SEDAR at www.sedar.com. EBY is listed on the Canadian Stock Exchange under the symbol "EBY". The MD&A is dated June 29, 2011.

BASIS OF PRESENTATION

The financial data presented below has been prepared in accordance with International Financial Reporting Standards.

Change in Accounting Policies

On January 1, 2011, the Company adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes, using a transition date of January 1, 2010. The unaudited financial statements for the three month ended March 31, 2011, including required comparative information, have been prepared in accordance with IFRS 1, First-time Adoption of International Financial Reporting Standards, and with International Accounting Standard ("IAS") 34, Interim Financial Reporting, as issued by the International Accounting Standards Board ("IASB"). Previously, the Company prepared its Interim and Annual Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). Unless otherwise noted, 2010 comparative information has been prepared in accordance with IFRS. The adoption of IFRS has not had an impact on the Company's operations, strategic decisions and funds from operations.

Application of Accounting Estimates

The significant accounting policies used by EBY are disclosed in Note 3 to the interim financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a periodic basis. The emergence of new information and changed circumstance may result in actual results or changes to estimated amounts that differ materially from current estimates.

Non-IFRS and Non-GAAP Measures

This MD&A includes the following measures that are from time to time used by the Company, but do not have any standardized meaning under IFRS or GAAP and may not be comparable to similar measures presented by other companies:

- a) "Funds from operations" - should not be considered an alternative to, or more meaningful than "cash flow from operating activities" as determined in accordance with IFRS as an indicator of the Company's financial performance. Funds from operations is determined by adding non-cash expenses to the net income or loss for the period, deducting decommissioning liability expenditures and does not include the change in working capital applicable to operating activities. Management believes that in addition to cash flow from operating activities, funds from operations is a useful supplemental measure as it provides an indication of the results generated by EBY's principal business activities before the consideration of how such activities are financed.

- b) "Operating netback" - Operating netbacks are calculated by deducting royalties and operating costs, including transportation costs, from revenues.
- c) "Net debt" – Net debt is calculated by deducting total current liabilities from total current assets.
- d) "Working capital" – working capital includes total current assets and total current liabilities. The working capital ratio is calculated by deducting total current liabilities.

BOE Presentation

The term "barrels of oil equivalent" (boe) may be misleading, particularly if used in isolation. A boe conversion of six thousand cubic feet of natural gas to one barrel of oil (6:1) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers should be aware that historical results are not necessarily indicative of future performance.

FORWARD-LOOKING STATEMENTS

Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward looking statements. These statements relate to future events or our 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.

In particular, this MD&A contains the following forward looking statements pertaining to, without limitation, the following:

The Company's future production volumes and the timing of additional production volumes will come on stream; The Company's realized price of commodities in relation to reference prices; the Company's future commodity mix; future commodity prices; the Company's expectations regarding future royalty rates and the realization of royalty incentives; The Company's expectation of future operating costs on a per unit basis; future general and administrative expenses; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected rate of depletion, depreciation and accretion; the estimated future contractual obligations of the Company; the future liquidity and financial capacity of the Company; and, The Company's ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

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

We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in, or incorporated

by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis: which include volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of The Company's stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry, changes in the regulatory regimes under which the Company operates, changes in the political and social environment that may impact the Company and the other factors discussed under "Risk Factors" in the following annual MD&A. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward looking statements contained in this document speak only as of the date of this document and The Company 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.

OPERATING RESULTS

SALES	Average Daily Volumes			Average Prices		
	March 31, 2011	March 31, 2010	Percent Change %	March 31, 2011	March 31, 2010	Percent Change %
Natural Gas (mcf)	423	654	(35.3%)	3.93	5.19	(24.3)
Oil (bbls)	5	8	(37.5%)	94.98	73.83	28.6
NGL (bbls)	10	11	(9.1%)	70.53	63.52	11.0
Barrels of Oil Equivalent (boe)	86	128	(32.8%)	33.33	36.60	(8.9)

For the period ended March 31, 2011 natural gas sales decreased by 35.3%, to 423 mcf/d from 654 mcf/d the previous year. This decrease was mainly due to certain wells being shut in due to the lower natural gas prices, as well as numerous weather related shut-ins. Additionally, previously drilled wells had not been brought on line and while certain wells won't be tied-in until natural gas prices rebound, there have been several wells brought on line in Q2.

Natural gas prices decreased an average of 24.3% during the period ended March 31, 2011 to \$3.93/mcf versus \$5.19/mcf during the same period in 2010.

Oil production for the period ended March 31, 2011 decreased to 5 bbls/d compared to 8 bbls/d for the period ended March 31, 2010. The variation was due to production related issues due to extremely cold and wet weather conditions during the period.

During the period ended March 31, 2011, the average price received for oil was \$94.98/barrel versus \$73.83/barrel during the previous year, a 28.6% increase. Most of EBY's production is medium viscosity crude which receives higher pricing.

During the period ended March 31, 2011, NGL sales decreased 9.1% to 10 bbls/d compared to 11 bbls/d in 2010. The average NGL price rose 11.0% to \$70.53/bbl compared to \$63.52/bbl received in 2010.

During the period ended March 31, 2011, the average sales volume on a boe/d basis decreased by 32.8% to 86 boe/d compared with 128 boe/d for the period ended March 31, 2010.

The average sales price on a boe basis was \$33.33/boe in 2011, a 8.9% decrease from the \$36.60/boe received in 2010.

On a barrel of oil equivalent basis, during the period ended March 31, 2011 oil and NGL accounted for 17.6% of total sales and natural gas accounted for 82.4% of total sales, compared to 2010 when oil and NGL accounted for 14%, with natural gas accounted for 86% of total sales.

FINANCIAL RESULTS

Revenue from the sale of petroleum and natural gas is recorded on a gross basis when title passes to an external party and is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including production, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

Three months ended March 31,	2011 (\$)	2010 (\$)	Percent Change (%)
Petroleum and natural gas revenue	259,954	422,383	(38.46)
Royalties, petroleum and natural gas	(34,184)	(96,565)	(64.60)
Production expenses, petroleum and natural gas	(147,961)	(144,313)	4.01
Operating netback, petroleum and natural gas	77,809	181,505	(57.13)
Net loss	(453,497)	(98,446)	460.19
Net loss per share (basic and diluted)	(0.01)	(0.00)	
Revenue per boe	33.33	36.60	(8.9)
Royalty per boe	4.38	8.37	(47.7)
Operating costs per boe	18.97	12.51	51.6
Operating netback per boe	9.98	15.72	(36.6)
Total assets	5,258,862	6,848,496	(4.5)
Total long-term liabilities	573,789	318,548	80.13

Petroleum and natural gas revenue declined 38.46% to \$259,954 for the three months ended March 31, 2011 from revenue of \$422,383 during the three months ended March 31, 2010. The reduction was due to certain wells being shut in and delays in bringing wells on line as the Company awaits a rebound in natural gas prices. Revenue on a boe basis decreased by 8.9% to \$33.33/boe from \$36.60 during the three months ended March 31, 2010.

Royalties decreased by 64.6% to \$34,184 from \$96,565 during the three months ended March 31, 2011. Royalty per boe for the three months ended March 31, 2011 averaged \$4.38/boe, which was a 47.7% decrease from \$8.37/boe during the three months ended March 31, 2010.

Production expenses in the three months ended March 31, 2011 increased to \$147,961 from the three months ended March 31, 2010 of \$144,313. Operating costs/boe for the three months ended March 31, 2011 increased by 51.6% to \$18.97/boe from \$12.51/boe in the three months ended March 31, 2010.

Operating netback from petroleum and natural gas sales decreased by 57.13% to \$77,809 during the three months ended March 31, 2011 from \$181,505 during the three months ended March 31, 2010, mainly due to lower production volumes.

Operating netback/boe decreased by 36.6% to \$9.98/boe from \$15.72/boe.

Royalties per unit of Production			
Three months ended March 31	2011	2010	Percent Change %
Gas (\$/mcf)	.32	1.02	(68.6)
Oil (\$/bbl)	1.04	4.96	(80.0)
NGL (\$/bbl)	23.68	32.50	(27.1)
Total (\$/boe)	4.38	8.37	(47.7)

The royalties per mcf for natural gas decreased by 68.6% to \$0.32/mcf from \$1.02/mcf in 2010. Oil royalties decreased by 80.0% to \$1.04/bbl from \$4.96/bbl in 2010. NGL royalties were 27.1% lower in 2011. Combined royalties for all products decreased by 47.7% to \$4.38/boe in 2011 from \$8.37/boe the previous year.

GENERAL & ADMINISTRATIVE EXPENSES

After recoveries, general and administrative expenses ("G&A") decreased by 15.51% to \$301,812 during the three months ended March 31, 2011 from \$357,199 for the same period during 2010. G&A expenses decreased throughout the period primarily due to the increased efficiencies within the Company.

GENERAL & ADMINISTRATIVE EXPENSES			
Three months ended March 31,	2011 (\$)	2010 (\$)	Percent Change (%)
Net G&A Expenses	301,812	357,199	(15.51)

STOCK BASED COMPENSATION

During the three month period ended March 31, 2011, there were no stock options grants, exercises or cancellations, and 1,000,000 options expired unexercised. There was no compensation expense recognized during the three months ended March 31, 2011 or during the same period in 2010.

DECOMMISSIONING LIABILITIES

Decommissioning liabilities are the present value of management's estimate of future costs to be incurred to properly abandon and reclaim the properties held by the Company. Accretion expense is the increase in the decommissioning liability resulting from the passage of time. Decommissioning liabilities increased by 1.57% from \$239,316 as at December 31, 2010 to \$243,078 as at March 31, 2011. The increase was primarily due to the accretion of the liabilities that existed at December 31, 2010.

DEPLETION & DEPRECIATION

Depletion and depreciation expense, an accounting measure of our finding and on-stream costs, is calculated using the ratio of capital costs to proven reserves. Capital costs include the net book value of historical costs incurred and estimated future expenditures to develop proved reserves less the estimated net realizable value of production equipment and facilities after proved reserves are fully developed.

DEPLETION, DEPRECIATION & ACCRETION

Three months ended March 31,	2011 (\$)	2010 (\$)	Change Percent %
Depletion, depreciation and accretion	93,248	122,979	(24.18)

During the three months ended March 31, 2011, depletion and depreciation expenses were 24.18% lower at \$93,248 compared to \$122,979 during the same period in 2010. The decrease was primarily due to the lower production volumes during 2011 compared to 2010.

CASH FLOWS FROM OPERATIONS

During the three months ended March 31, 2011, cash flows used in operations increased to \$319,580 from \$210,352 during the same period in 2010. This increase was primarily due to lower revenue and working capital fluctuations.

Funds used in operations during the three months ended March 31, 2011 decreased to \$221,921 from the previous year's \$237,378. The decrease in funds used in operations was predominately due to lower royalties and general and administrative costs during 2011 as compared to 2010.

CAPITAL EXPENDITURES

CAPITAL EXPENDITURES

Three months ended March 31,	2011 (\$)	2010 (\$)	Percent Change %
Capital expenditures	(4,665)	82,875	(105.63)

The decrease of 105.63% in capital expenditures during 2011 as compared to 2010 was primarily due to lower natural gas prices delaying certain projects until there is a rebound in the commodity price.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of selected quarterly information that has been derived from the unaudited financial statements of EBY. This summary should be read in conjunction with unaudited financial statements of EBY as contained in the public record.

Quarterly Financial Information	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30
(\$000 except per share and unit values)	2011	2010	2010	2010	2010	2009	2009	2009
Petroleum and natural gas sales	260	224	315	375	422	486	301	316
Net loss	(453)	(1,492)	(357)	(279)	(98)	(1,005)	(281)	(450)
Net loss per share								
Basic and diluted	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)	(0.03)	(0.01)	(0.02)
Average daily sales								
Natural gas (mcf/d)	423	470	553	585	654	781	668	606
Oil/NGL (bbls/d)	15	22	17	23	19	19	29	26
Barrels of oil equivalent (boe/d)	86	100	109	121	128	149	140	128
Average sales prices								
Natural Gas (\$/mcf)	3.93	2.15	4.59	4.51	5.19	4.36	2.59	4.17
Oil/NGL (\$/bbl)	78.91	66.09	52.69	63.56	67.74	96.22	52.82	35.54
Barrels of oil equivalent (\$/boe)	33.33	24.37	31.42	34.13	36.60	35.47	23.29	27.23
Operating costs (\$/boe)	18.97	16.32	13.77	15.97	12.51	33.92	13.85	16.10
Royalty Expense (\$/boe)	4.38	5.66	5.49	3.60	8.37	6.63	3.27	4.53
Operating netback (\$/boe)	9.98	2.39	12.16	14.56	15.72	(5.08)	6.17	6.60

Explanation of Quarterly Variances

On a quarter by quarter basis production volumes trended up throughout 2009, but as prices continued to be significantly lower than forecasted throughout 2010 and into Q1 2011 projects were delayed and certain wells were shut in until such time that Natural Gas commodity prices rebound. The net loss in the quarters is largely a result of these factors.

LIQUIDITY & CAPITAL RESOURCES

The Company has a \$3,000,000 (December 31, 2010 - \$3,000,000) revolving operating demand loan (the "Revolving Loan"), of which \$2,825,000 (December 31, 2010 - \$2,875,000), has been drawn at March 31, 2011. Interest on the Revolving Loan is calculated daily and payable monthly on the outstanding principal amount drawn at a rate per annum equal to the bank's prime rate plus 2.00% (December 31, 2010 - bank's prime rate plus 2.00%).

During the year ended December 31, 2010, the Company obtained a non-revolving demand loan (the "Non-revolving Loan") of \$400,000 through the same bank holding the Revolving Loan. Interest on the non-revolving loan is calculated daily and payable monthly on the outstanding principal amount at a rate per annum equal to the bank's prime rate plus 2.50% (December 31, 2010 - bank's prime plus 2.50%). The full amount was drawn as at March 31, 2011 and December 31, 2010.

The Company is bound by certain debt covenants. These covenants include maintaining a Working Capital Ratio of not less than 1.0 to 1.0 at all times. The Working Capital ratio for this purpose is defined as Current Assets (including the undrawn availability under the Credit Facility A) to Current Liabilities (excluding any current portion of Bank Debt). As at March 31, 2011, the Company was in violation of this bank covenant with a ratio of 0.40:1 (December 31, 2010 - 0.38:1). The bank has not made demand of the Company's credit facilities but retains the right to do so.

In order to resolve its working capital ratio and to access additional share equity, the Company will be emphasizing development of its U.S. properties. The Company has received preliminary expressions of interest from third parties, interested in investing substantial sums in the Company if it focuses on its US properties. The Company's US prospect should produce better returns due to higher oil prices compared with natural gas, it has greater drilling potential and more locations. Given Emerald Bay's recurring operating losses it is critical that the Company refocus to an area with the potential of growth and positive cash flow and income that the U.S. has.

OUTSTANDING SHARE DATA

On March 18, 2011, the Company issued 532,812 common shares with a value of \$42,625 (\$0.08 per share). The common shares were issued as consideration for the purchase of a 100% interest in an oil and gas lease in Texas.

On March 29, 2011, the Company completed a private placement, issuing 7,503,701 units for total proceeds of \$375,185, (\$0.05 per unit). Each unit consists of one common share of the Company (issued either as a common share or as a FTS) and one share purchase warrant ("Warrant"). Each Warrant entitles the holder to purchase one additional common share of the Company at \$0.10 per share, exercisable for 18 months from the date of the private placement. Of the total 7,503,701 units issued, 6,163,701 were issued as a FTS. The Company has allocated \$48,737 of the unit value to warrants. Pursuant to the private placement, the Company incurred \$41,680 in cash share issue costs and issued 470,000 finders options valued at \$6,353.

The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares issuable in series. As of the date hereof, the Company's issued share capital and the outstanding securities that are convertible into or exercisable or exchangeable for any voting or equity securities of the Company is as follows

	June 29, 2011	March 31, 2011
Common Shares	77,255,959	71,345,959
Warrants (i)	26,563,701	20,653,701
Stock Options (ii)	3,060,000	3,060,000

Notes:

- i) 8,350,000 of the Warrants entitle the holder to acquire one additional common share for \$0.12 per share until September 30, 2011. 500,000 of the Warrants entitle the holder to acquire one additional common share for \$0.12 per share until October 27, 2011. 4,300,000 of the Warrants entitle the holder to acquire one additional common share for \$0.12 per share until December 30, 2011. 7,503,701 of the Warrants entitle the holder to acquire one additional common share for \$0.10 per share until September 29, 2012. 1,910,000 of the Warrants entitle the holder to acquire one additional common share for \$0.10 per share until October 13, 2012. 4,000,000 of the Warrants entitle the holder to acquire one additional common share for \$0.10 per share until December 13, 2012.
- ii) 300,000 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.10 per share until June 25, 2012. 2,760,000 of the Stock Options entitle the holders to acquire an equal number of common shares at \$0.10 per share until April 6, 2015.

OFF BALANCE SHEET ARRANGEMENTS

The Company is not party to any arrangements that would be excluded from the balance sheet.

RELATED PARTIES

- a) The following amounts are due by related parties:

	March 31, 2011	December 31, 2010
	\$	\$
Note receivable from officer (i)	226,671	225,054
Fair value allowance (ii)	(206,710)	(206,710)
Net note receivable	19,961	18,344
Advance fees (iii)	27,029	33,029
	<u>46,990</u>	<u>51,373</u>

- (i) A promissory note was issued to an officer of the Company bearing interest at 3% per annum and repayable by December 31, 2012, unless the officer's employment is terminated or he is petitioned into bankruptcy wherein the note and accrued interest becomes immediately payable. The note is secured by 393,000 common shares of the Company which had a fair value of \$23,580 at March 31, 2011 (December 31, 2010 - \$19,650).
- (ii) The fair value allowance was determined in 2008, based on the market value of the secured shares at December 31, 2008. The Company has not provided an additional allowance to the estimated fair value of the 393,000 common shares held as security as the fair value at March 31, 2011 and December 31, 2010 exceeded the carrying amount.
- (iii) During the year ended December 31, 2008, a director was advanced \$59,473 in relation to efforts to finance and advance the Company's drilling technology. At March 31, 2011 \$27,029 (December 31, 2010 - \$33,029) remains

outstanding. There is no guarantee that such efforts will be successful and if such efforts are not successful, the full balance will be repaid. During the year ending December 31, 2010, the original repayment date of December 31, 2010 was extended to December 31, 2011.

- b) Additional related party transactions during the three months ended March 31, 2011 are as follows:
- (i) Aggregate fees of \$7,350 (March 31, 2010 - \$nil) were charged by directors of the Company. Of this amount \$4,200 was recorded in the statement of comprehensive loss and \$3,150 was capitalized to property and equipment.
 - (ii) Aggregate consulting fees of \$48,688 (March 31, 2010 - \$70,773) were charged by directors and officers of the Company and were expensed as general and administrative expenses.
 - (iii) Aggregate fees of \$13,800 (March 31, 2010 - \$10,800) were charged by a U.S. corporation, which is owned and controlled by an officer and a director of the Company for costs it incurred for operation of the Company's U.S. properties. Of this amount \$10,800 (March 31, 2010 - \$10,800) was recorded in the statement of comprehensive loss and \$3,000 was capitalized to property and equipment.
 - (iv) Included in accounts payable at March 31, 2011 was \$26,238 owing to related parties of the Company and included in accounts received is \$30,536 owing to the Company from related parties.

Transactions in the normal course of operations are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

COMMITMENTS

- a) Under a lease agreement for five years commencing April 1, 2009 and ending March 31, 2014, the Company has committed to payments of \$5,420 per month for the lease of its office space.
- b) The Company has entered into various vehicle loan agreements with estimated minimum annual payments of approximately \$27,800 per year through 2015. Total annual principal repayments for fiscal years 2011 through to 2015 are respectively as follows: \$22,075, \$23,345, \$24,688, \$26,110 and \$15,846.
- c) As partial consideration for the non-controlling acquisition of the shares of a Texas oil and gas company, the Company has entered into a consulting contract aggregating \$37,919 (USD -\$36,800). The contract commences March 1, 2010 and has a term of 18 months.
- d) The Company is committed to renounce to subscribers \$410,000 and \$308,185 of expenditures that qualify as cumulative exploration expenditures ("CEE") for Canadian income tax purposes and to incur these expenditures no later than December 31, 2011 and December 31, 2012, respectively.

SUBSEQUENT EVENTS

The Company entered into the following transactions subsequent to March 31, 2011:

- a) The final tranche of a private placement was completed through the issuance of an additional 1,910,000 units at a price of \$0.05 per unit for aggregate proceeds of \$95,500. Each unit consisted of one common share of the Company and one share purchase warrant. Each full share purchase warrant entitles the holder to purchase one additional common share of the Company at \$0.10 per share, exercisable for 18 months from the date of the final placement. Of the 1,910,000 common shares that were issued under this final tranche, none were issued as flow-through shares.
- b) The Company closed a private placement through the issuance of 4,000,000 units for total proceeds of \$200,000, (\$0.05 per unit). Each unit consisted of one common share of the Company (issued as either a common share or as a flow-through share) and one share purchase warrant. Each full share purchase warrant entitles the holder to purchase one additional common share of the Company at \$0.10 per share, exercisable for 18 months from the date of the private placement. Of the total 4,000,000 units issued, 1,040,000 were issued as flow-through shares.

RISK FACTORS AND RISK MANAGEMENT

The oil and gas industry is subject to risks in (among others):

Commodity Price Risk

Historically the Company has sold its entire product on the spot market. However, the Company was concerned about the near future value natural gas and therefore the Company has entered into various derivative financial instruments. During 2010, the Company entered into a derivative financial instrument, which became effective on January 1, 2011 to December 31, 2011. This instrument fixes the received price of natural gas at CDN 4.684 per GJ. As at March 31, 2011, based on the fair market value of the contract, the Company has recorded an unrealized loss in the statement of comprehensive loss of \$30,079.

During 2010, the Company entered into two commodity call options. The first option is effective from January 1, 2011 to December 31, 2011 and the second option is effective from January 1, 2012 to December 31, 2012. Both Options have a strike price of USD \$90.00 per BBL. As at March 31, 2011, based on the fair market value of the contract, the Company has recorded an unrealized loss in the statement of comprehensive loss of \$222,111.

The realized gain recorded by the Company on the derivative financial instruments for the three months ended March 31, 2011 was \$49,982.

Production Risk

The Company believes it has a stable production base from a variety of wells. However, the Company remains subject to the risk that a significant decrease in production from some wells could result in a material decrease in the Company's production and associated cash flow.

Reserve Replacement Risk

EBY's production is subject to natural declines and the Company plans to replace production with acquisitions and developing new reserves. To remain financially viable, the Company must be able to replace reserves at a lesser cost on a per unit basis than its cash flow on a per unit basis. The Company closely monitors the capital expenditures made for the purpose of increasing its petroleum and natural gas reserves.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant impact on EBY's finances and operations. EBY strives to remain knowledgeable regarding changes to the regulatory regime under which it operates. All EBY properties are currently located in Alberta. Sudden regulatory or royalty changes by future government action is unpredictable and cannot be forecast by the Company.

Climate Change Risk

North American climate change policy is evolving and changing at both regional and national levels. EBY expects that some of its operations may be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas. The exact scope and timing of new climate change measures is difficult to predict.

FINANCIAL INSTRUMENTS

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers.

Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its oil and natural gas marketers. Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval of significant capital expenditures. However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venturers; as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venturers; however, the Company does have the ability to withhold production from joint venturers in the event of non-payment.

The Company does not anticipate any significant defaults as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. A provision for doubtful accounts has not been recorded at March 31, 2011 (December 31, 2010 - \$5,917).

Cash and cash equivalents consist of cash bank balances held in both interest and non-interest bearing accounts. The Company manages credit exposure of cash by selecting financial institutions with high credit ratings.

(b) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

The Company's net current liabilities and other liabilities and the manner in which they are expected to be met are as follows:

Net working capital deficiency (excluding Bank Loan)	\$1,795,785	This amount is anticipated to be met out of additional share issuance in the 2011 fiscal period.
Bank loan	\$3,225,000	The Company anticipates issuing additional share capital to reduce this amount in 2011. This amount is secured by the Company's oil and gas assets which have value sufficient such that the Company has no reason to believe that the bank will require repayment within the next fiscal year.
Long term debt	\$84,272	Vehicle loans will be paid over the next 4 years out of normal cash flow.

(c) Market risk:

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while maximizing returns.

(i) Commodity price risk:

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand. All of the Company's oil and gas production is sold at spot rates exposing the Company to the risk of price movements.

As a means to mitigate the exposure to commodity price volatility, the Company entered into the following derivative financial instruments:

During 2010, the Company entered into a derivative financial instrument, which became effective on January 1, 2011 to December 31, 2011 ("Option A"). This instrument fixes the received price of natural gas at CDN 4.684 per GJ. As at March 31, 2011, based on the fair market value of the contract, the Company has recorded an unrealized loss in the statement of comprehensive loss of \$30,079.

During 2010, the Company entered into two commodity call options. The first option (“Option B”) is effective from January 1, 2011 to December 31, 2011 and the second option (“Option C”) is effective from January 1, 2012 to December 31, 2012. Both Options have a strike price of USD \$90.00 per BBL. As at March 31, 2011, based on the fair market value of the contract, the Company has recorded an unrealized loss in the statement of comprehensive loss of \$222,111.

The following table summarizes the fair value of the Options as at March 31, 2011:

	Option A (\$)	Option B (\$)	Option C (\$)
Fair market value, December 31, 2010	162,458	(165,736)	(150,489)
Unrealized (loss)	(30,079)	(126,161)	(95,950)
Fair market value, March 31, 2011	<u>132,379</u>	<u>(291,897)</u>	<u>(246,439)</u>
Financial Contract liability:			
Current	(159,518)		
Long-term	(246,439)		

The realized gain recorded by the Company on the derivative financial instruments for the three months ended March 31, 2011 was \$49,982 (March 31, 2010 – realized loss \$24,520).

(ii) Currency risk:

The Company is exposed to the financial risk related to the fluctuation of foreign exchange rates. The Company operates in Canada and the United States and a portion of its expenses are incurred in US dollars. The Company does not hedge its exposure to fluctuations in the exchange rate. Future changes in exchange rates could have a material effect on the Company’s business including its intended capital plans, its financial condition and results of operations.

Certain of the Company’s financial instruments are exposed to fluctuations in the US dollar, including cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities. As at March 31, 2011, an increase or decrease of 10% to the foreign exchange rate between the US dollar and the Canadian dollar applied to the average level of US denominated cash and cash equivalents would have had approximately a \$7,200 impact on the Company’s comprehensive loss for the period.

(iii) Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. At March 31, 2011 the Company’s bank debt was \$3,225,000 (December 31, 2010 - \$3,275,000). As at March 31, 2011, if interest rates had been 1 percent higher/lower, with all other variables held constant, there would have been an impact of approximately \$8,000 on the Company’s comprehensive loss for the period.

The Company has no interest rate swaps or financial contracts in place as at or during the three month period ended March 31, 2011 or during the year ended December 31, 2010.

(d) Capital management:

The Company’s capital consists of shareholders’ equity, bank debt and working capital. The Company will adjust its capital structure to manage its current and future debt, drilling programs and potential corporate acquisitions through the issuance of shares, increasing the credit facility line and adjustments to capital spending. The Company’s objective for managing capital is to maximize long-term Shareholder value by ensuring adequate capital to achieve the Company’s objectives.

Management reviews its capital management approach on an ongoing basis and believes its current approach is reasonable given the size of the Company. There has been no change in managements approach to capital management during the period.

As at March 31, 2011, the Company is in violation of the Working Capital Ratio required to be maintained pursuant to the Bank Loan.

OUTLOOK

In addition to the current pipeline operations in Alberta, and based on the continuation of low natural gas prices, Emerald Bay has transitioned its development focus to oil development primarily in Texas as well as Alberta. The initial impact of this transition shows a lower production volume in our overall output. The daily production rates in our PRI affiliate is not reported in Emerald Bay's average daily production rate. These volumes will be periodically reported through press releases after we are confident we have completed our land acquisition efforts in the area.

We will continue to pursue a carefully designed capital expenditure program, including acquisitions and dispositions, which would allow us to add production, reserves and cash flow in a cost effective manner while maintaining a level of flexibility in our balance sheet. We are confident that we have prepared ourselves to emerge from this environment operationally strong, and we expect to be well positioned to respond quickly when the business environment improves. Our proven management and dedicated team of professionals are engaged and committed to developing our high-quality asset base.

ACCOUNTING POLICIES

The Company's IFRS accounting policies are provided in Note 3 to the Interim financial statements for the three months ended March 31, 2011 and, in addition, Note 19 in the interim financial statements presents reconciliation between the Company's 2010 previous GAAP results and the 2010 IFRS results. The reconciliations include the Statement of Financial Position as at January 1, 2010, March 31, 2010 and December 31, 2010, and the Statements of Operations, Comprehensive Loss and Deficit for the three months ended March 31, 2010 and for the twelve months ended December 31, 2010.

a) Impairment

(i) Exploration and evaluation ("E&E") assets

E&E assets consist of the Company's exploration projects where technical feasibility and commercial viability have not yet been determined. Under Canadian GAAP these costs were grouped with property and equipment. Under IFRS, E&E assets are classified as a separate line in the balance sheet. E&E costs of \$344,720 were identified and deemed to be impaired upon transition.

(ii) Impairment of development and production ("D&P") assets

The net book value at December 31, 2009 under Canadian GAAP was allocated between CGU's based on total proven reserve values. Each CGU was tested for impairment on the transition date, a requirement when applying the "deemed cost" exemption under IFRS 1.

IAS 36 "Impairment of Assets" requires that an assessment must be made at each reporting period whether there is any indication that an asset or CGU may be impaired. The Company determined that an impairment of \$874,281 was required as at December 31, 2010.

b) Decommissioning liability

Under Canadian GAAP, decommissioning liabilities were discounted at a credit adjusted risk free rate of 7.5%. Under IFRS, the estimated cash flow to abandon and remediate the wells has been risk adjusted and therefore the entire decommissioning liability is discounted at a risk free rate of 3.75%.

c) Reclassifications

(i) E&E assets

E&E assets consist of the Company's exploration projects where technical feasibility and commercial viability have not yet been determined. Under Canadian GAAP these costs were grouped with property and equipment. Under IFRS, E&E assets are classified as a separate line in the balance sheet.

(ii) Accretion on decommissioning liability

Under Canadian GAAP, unwinding of the discount on the decommissioning liability, or accretion, was included in depletion and depreciation. Under IFRS it is included in finance expense.

(iii) Interest expense and foreign exchange gains and losses

Under IFRS interest expense and foreign exchange gains and losses are required to be included in finance expense.

d) Depletion:

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over total proven reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components.

e) Share-based payments

Under IFRS each tranche of an award with different vesting dates is considered a separate grant for the calculation of fair value, and the resulting fair value is amortized over the vesting period of the respective tranches. The Company followed this treatment under Canadian GAAP.

Under Canadian GAAP, forfeitures of awards were recognized as they occurred. Under IFRS, forfeiture estimates are recognized on the grant date and revised for actual experiences in subsequent periods. The estimate of the forfeiture rate used is based on historical forfeitures. This resulted in a lower stock-based compensation expense under IFRS.

f) Pre-license costs

Under Canadian GAAP, the Company capitalized pre-license assets. The Company incurred these expenditures prior to obtaining a legal right to explore an area. Under IFRS, the Company is required to expense pre-license costs and resulted in a reduction in the property and equipment balance at December 31, 2010, with a corresponding charge to deficit.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the interim financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Specific amounts and disclosures affected by estimates and assumptions are:

Reserves

Amounts recorded for depreciation, depletion and amortization and amounts used for impairment calculations are based on estimates of oil and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows are subject to measurement uncertainty.

Determination of cash-generating units ("CGU")

Property and equipment are aggregated into CGUs based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's cash-generating units is subject to management's judgment.

Decommissioning liabilities

The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require judgmental assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating costs, future removal technologies in determining the removal costs, and liability specific discount rates to determine the present value of these cash flows.

Exploration and evaluation assets

The application of the exploration and evaluation accounting policy requires management to make certain estimates and assumptions as to future events and circumstances as to whether economic quantities of reserves have been found.

Share-based compensation

Compensation costs accrued for share-based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as the Black-Scholes model which is based on significant assumptions such as the future volatility of the market price of the Company's shares and the expected term of the issued stock option.

Income taxes

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing, likelihood and reversal of temporary differences between accounting and tax bases of assets and liabilities.

FUTURE ACCOUNTING AND REPORTING CHANGES

The Company has reviewed the new and revised accounting pronouncements that have been issued but are not yet effective and determined that the following may have an impact on the Company:

As of January 1, 2013, the Company will be required to adopt IFRS 9 – "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39 – "Financial Instruments: Recognition and Measurement". The new

standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The adoption of this standard should not have a material impact on the Company's financial statements.

In May 2011, the IASB issued the following standards which have not yet been adopted by the Company: IFRS 10 – “Consolidated Financial Statements”, IFRS 13 – “Fair Value Measurement” and amended IAS 28 – “Investments in Associates and Joint Ventures”. Each of the new standards is effective for annual period beginning on or after January 1, 2013 with early adoption permitted. The Company has not yet begun the process of assessing the impact that these new and amended standards will have on the Company's financial statements or whether to early adopt any of the new requirements.