Emerald Bay Energy

President's Message

In 2011, our business model continued to be driven by a low natural gas price that continued to deteriorate to a level well below the price required to profitably add new production and produce existing production. We believe these prices are unsustainably low, yet they continue to dominate our business and impact our performance. While many factors have contributed to the current natural gas surplus, and it is now quite obvious that a substantial decrease in natural gas drilling activity in North America will be required to restore market balance. Working through the supply issues will take time and Emerald Bay will need to weather this economic storm by adapting to the natural gas market reality by maintaining our focus towards growing our oil production.

2011 Highlights:

- Sold non-strategic assets for debt reduction and working capital. We reduced our debt by approximately $1 million.
- Reduced management/staff compensation by 30%
- Increased South Texas land position in Medina and Guadalupe Counties, Texas
- Negotiated a participation agreement with Eagle Energy Acquisitions, a subsidiary of Eagle Energy Trust on our Wooden Horse project in Guadalupe County Texas.

2012 Highlights to Date and Objectives:

- Sold additional Alberta natural gas assets to reduce bank debt by another $1.7 million.
- Drilled, cased, and cemented the first test well on the Wooden Horse prospect in Guadalupe County. The open-hole logs, core analysis, and swab testing results support original optimism about this prospect.
- Currently awaiting permit to drill a salt water disposal well before initiating production operations.
- With our current land position, we feel we have good control of the Wooden Horse play for future development.
- 12 "in-fill" oil wells are projected to be drilled in the Taylor-Ina field in Medina County, Texas through our 25% ownership in Production Resources Inc in May, June, and July. The rig has been contracted and will spud the first well on May 1st.
- The Company continues its land and production acquisitions in South Texas, and formations of interest will continue to be where the Company has specific experience; such as the Escondido, Olmos, Austin Chalk, Eagle Ford, Buda, and Edwards.

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.

Best Regards,

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") audited annual financial statements for the year ended December 31, 2011. 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 May 1, 2012.

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. These annual financial statements have been prepared in accordance with accounting policies consistent with IFRS as issued by the International Accounting Standards Board ("IASB") and Interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"); and with IFRS 1: First-time Adoption of International Reporting Standards. Note 21 and 22 to the annual financial statements discloses the impact of the transition to IFRS on the Company's reported equity as at the transition date of January 1, 2010 and December 31, 2010 and net loss and comprehensive loss for the year ended December 31, 2010, including the nature and effect of significant changes in accounting policies.

Application of Accounting Estimates

The significant accounting policies used by EBY are disclosed in Note 3 to the annual 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 may contain 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 forward looking statements contained herein 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 MD&A, 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.

SELECTED YEAR TO DATE FINANCIAL INFORMATION

	Three months ended December 31			**Year ended December 31**		
	2011	**2010**	**Change %**	**2011**	**2010**	**Change %**
FINANCIAL						
Gross revenue	213,434	200,215	7%	1,082,351	1,311,685	(17%)
Total assets	3,667,179	5,170,320	(29%)	3,667,179	5,170,320	(29%)
Cash flow from (used in) operations	325,774	(970,836)	134%	(468,601)	(1,398,929)	(67%)
Per share – basic and diluted	0.00	(0.01)	(100%)	(0.01)	(0.03)	(67%)
Net comprehensive loss	(1,523,982)	(1,668,170)	(9%)	(1,977,056)	(2,401,922)	(18%)
Per share – basic and diluted	(0.03)	(0.04)	(25%)	(0.03)	(0.05)	(40%)
Capital expenditures	10,240	294,850	(97%)	88,236	680,762	(87%)
Bank loan	2,675,000	3,275,000	(18%)	2,675,000	3,275,000	(18%)
OPERATIONS						
Production sales						
Oil (bbls/d)	5	11	(55%)	7	8	(13%)
Natural gas (mcf/d)	296	470	(37%)	406	565	(28%)
NGL (bbls/d)	12	11	9%	12	12	-
Total (boe/d @ 6 mcf: 1 bbl)	66	100	(34%)	86	114	(25%)
Average pricing						
Natural gas ($/mcf)	3.35	2.15	56%	3.83	4.11	(7%)
Oil and NGL's($/bbl)	77.19	66.09	17%	77.55	62.93	23%
Combined ($/boe)	34.79	24.37	43%	34.54	31.43	10%
Expenses						
Production expense & transportation ($/boe)	17.93	16.32	10%	19.00	14.55	31%
Royalty expense ($/boe)	5.44	5.66	(4%)	4.64	5.82	(20%)
Net Back Combined ($/boe)	11.41	2.39	377%	10.90	11.06	(1%)

Financial and Operations 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.

Petroleum and natural gas revenue was $213,434 and $1,082,351 for the three and twelve months ended December 31, 2011, respectively, from revenue of $200,215 and $1,311,685 during the three and twelve months ended December 31, 2010, respectively.

Natural gas prices increased to $3.35/mcf and decreased to $3.83/mcf in the three and twelve months ended December 31, 2011, respectively, versus $2.15/mcf and $4.11/mcf in the three and twelve months ended December 31, 2010, respectively. Oil and NGL combined prices increased to $77.19 in the three months ended December 31, 2011 from $66.09 in the three months ended December 31, 2010 and increased to $77.55 in the twelve months ended December 31, 2011 from $62.93 in the twelve months ended December 31, 2010. The average sales price on a boe basis was $34.79 and $34.54 in the three and twelve months ended December 31, 2011, respectively, compared to $24.37 and $31.43 in the three and twelve months ended December 31, 2010.

During the three and twelve months ended December 31, 2011, the average sales volume on a boe/d basis decreased to 66 boe/d and 86 boe/d, respectively, compared with 100 boe/d and 114 boe/d for the three and twelve months ended December 31, 2010.

During the three and twelve months ended December 31, 2011, cash flows used in operations decreased to $325,774 and ($468,601), respectively, from ($970,836) and ($1,398,929) during the three and twelve months ended December 31, 2010.

Due to the continued decline in Natural Gas prices revenues decreased significantly in 2011. Additionally, as prices continued to decline certain wells were shut in to preserve reserves until prices rebound.

OPERATING RESULTS

	Average Daily Volumes			Average Prices		
SALES	December 31, 2011	December 31, 2010	Percent Change %	December 31, 2011	December 31, 2010	Percent Change %
Natural Gas (mcf)	406	565	(28%)	3.83	4.11	(7%)
Oil (bbls)	7	8	(13%)	90.55	73.01	24%
NGL (bbls)	12	12	-	70.10	55.71	26%
Barrels of Oil Equivalent (boe)	86	114	(25%)	34.54	31.43	10%

For the year ended December 31, 2011 natural gas sales decreased by to 406 mcf/d from 565 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 previously drilled wells not being brought on line until natural gas prices rebound.

Natural gas prices decreased during the year ended December 31, 2011 to $3.83/mcf versus $4.11/mcf during the same period in 2010.

Oil production for the year ended December 31, 2011 decreased to 7 bbls/d compared to 8 bbls/d for the year ended December 31, 2010.

During the year ended December 31, 2011, the average price received for oil was $90.55/barrel versus $73.01/barrel during the previous year. The majority of EBY's production is medium viscosity crude which receives higher pricing.

During the year ended December 31, 2011 and 2010, NGL sales remained unchanged at 12 bbls/d. The average NGL price rose to $70.10/bbl compared to $55.71/bbl received in 2010.

During the year ended December 31, 2011, the average sales volume on a boe/d basis decreased to 86 boe/d compared with 114 boe/d for the period ended December 31, 2010.

The average sales price on a boe basis was $34.54/boe in 2011, an increase from $31.43/boe received in 2010.

On a barrel of oil equivalent basis, during the year ended December 31, 2011 oil and NGL accounted for 22% of total sales and natural gas accounted for 78% of total sales, compared to 2010 when oil and NGL accounted for 17.5%, with natural gas accounted for 82.5% 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.

Year ended December 31,	2011 ($)	2010 ($)	Percent Change (%)
Petroleum and natural gas revenue	1,082,351	1,311,685	(17%)
Royalties, petroleum and natural gas	145,361	243,103	(40%)
Production expenses, petroleum and natural gas	595,445	610,736	(3%)
Operating netback, petroleum and natural gas	341,545	457,846	(25%)
Net loss	1,977,056	2,401,922	(18%)
Net loss per share (basic and diluted)	(0.03)	(0.05)	(40%)
Revenue per boe	34.54	31.43	10%
Royalty per boe	4.64	5.82	(20%)
Operating costs per boe	19.00	14.55	31%
Operating netback per boe	10.90	11.06	(1%)

Petroleum and natural gas revenue decreased to $1,082,351 for the year ended December 31, 2011 from revenue of $1,311,685 during the year ended December 31, 2010. Revenue on a boe basis increased to $34.54/boe from $31.43 during the year ended December 31, 2010.

Royalties decreased to $145,361 during the year ended December 31, 2011 compared to the same period in 2010 of $243,103. Royalty per boe for the year ended December 31, 2011 averaged $4.64/boe, which was decrease from $5.82/boe during the year ended December 31, 2010.

Production expenses in the year ended December 31, 2011 decreased to $595,445 from the year ended December 31, 2010 of $610,736. Operating costs/boe for the year ended December 31, 2011 increased to $19.00/boe from $14.55/boe in the year ended December 31, 2010.

Operating netback from petroleum and natural gas sales decreased to $341,546 during the year ended December 31, 2011 from $457,846 during the year ended December 31, 2010.

Operating netback/boe decreased to $10.90/boe from $11.06/boe.

The Company’s revenue decrease reflects significantly lower commodity prices.

Royalties per unit of Production			
Year ended December 31,	2011	2010	Percent Change %
Gas ($/mcf)	0.37	0.58	(36%)
Oil ($/bbl)	6.27	5.21	20%
NGL ($/bbl)	18.69	24.95	(25%)
Total ($/boe)	4.64	5.82	(20%)

The royalties per mcf for natural gas decreased to $.37/mcf from $.58/mcf in 2010. Oil royalties increased to $6.27/bbl from $5.21/bbl in 2010. NGL royalties decreased to $18.69/bbl from $24.95/bbl in 2010. Combined royalties for all products decreased to $4.64/boe in 2011 from $5.82/boe the previous year.

GENERAL & ADMINISTRATIVE EXPENSES

After recoveries, general and administrative expenses ("G&A") increased to $1,229,864 during the twelve months ended December 31, 2011 from $1,159,410 for the same period during 2010. The small increase in the Company's G&A is reflective of the increase in activities relating to the Company's opportunities for oil development in South Texas.

GENERAL & ADMINISTRATIVE EXPENSES			
Year ended December 31,	2011 ($)	2010 ($)	Percent Change (%)
Net G&A Expenses	1,229,864	1,159,410	6%

STOCK BASED COMPENSATION

During the year ended December 31, 2011, there were 4,925,000 stock options granted, 305,000 options were cancelled or exercised, and 1,000,000 options expired unexercised. Compensation expense of $79,982 was recognized during the year ended December 31, 2011 (December 31, 2010 - $87,648).

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 decreased from $239,316 as at December 31, 2010 to $201,664 as at December 31, 2011. The decrease was primarily due to the disposal of certain Canadian and US oil and gas interests that existed as 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			
Year ended December 31,	2011 ($)	2010 ($)	Change Percent %
Depletion, depreciation and accretion	394,232	495,003	(20%)

During the year ended December 31, 2011, depletion and depreciation expenses lower at $394,232 compared to $495,003 during the same period in 2010. The decrease was primarily due to the lower production volumes during 2011 compared to 2010 due to lower commodity prices and the disposal of certain oil and gas assets during the year ended December 31, 2011.

IMPAIRMENT

IMPAIRMENT			
Year ended December 31,	2011 ($)	2010 ($)	Change Percent %
Impairment of property and equipment	356,515	897,480	(60%)
Impairment of assets held for sale	385,341	-	-
Impairment of evaluation and exploration assets	25,081	-	-

During the year ended December 31, 2011, due to unexpected accelerated reserve declines, the Company tested its property and equipment for impairment. The recoverable amount of each CGU was estimated based on the higher of the value in use and the FVLCTS. The estimate of FVLCTS was determined using a discount rate of 10% percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report. The prices used to estimate the FVLCTS are those used by independent industry reserve engineers. Based on the assessment at December 31, 2011, the carrying amount of the property and equipment was determined to be $356,515 higher (December 31, 2010 - $897,480) than its recoverable amount, and an impairment loss was recognized.

Prior to December 31, 2011, management was committed to selling certain oil and gas assets and was actively marketing and accepting purchase proposals. Accordingly at December 31, 2011, these assets were presented as assets held for sale. The disposition of the assets was completed on March 16, 2012 for gross proceeds of $1,500,000. The carrying value of the assets held for sale exceeded the highest purchase proposal received, and consequently an impairment of $385,341 was recorded in the statement of comprehensive loss.

As at December 31, 2010 an amount of $25,081 of E&E assets were acquired and represent the acquisition of undeveloped land within Alberta. At December 31, 2011, the Company determined that it no longer had the rights to the undeveloped land and recorded an impairment of the aggregate value.

CASH FLOWS FROM OPERATIONS

During the year ended December 31, 2011, cash flows used in operations decreased to $468,601 from $1,398,929 during the same period in 2010. This decrease was primarily due to working capital fluctuations.

Funds used in operations during the year ended December 31, 2011 increased to $1,071,428 from the previous year's $746,336. The increase in funds used in operations was predominately due to lower revenues and higher general and administrative costs and operating costs during 2011 as compared to 2010.

CAPITAL EXPENDITURES

CAPITAL EXPENDITURES			
Year ended December 31,	2011 ($)	2010 ($)	Percent Change (%)
Capital expenditures	88,236	680,762	(87%)

The decrease 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 ($000 except per share and unit values)	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**	**Sep 30 2010**	**Jun 30 2010**	**Mar 31 2010**
Petroleum and natural gas sales	213	260	349	260	200	315	375	422
Net income (loss)	(1,524)	150	(150)	(453)	(1,668)	(357)	(279)	(98)
Net loss per share								
Basic and diluted	(0.03)	0.00	(0.00)	(0.01)	(0.04)	(0.01)	(0.01)	(0.00)
Average daily sales								
Natural gas (mcf/d)	296	401	501	423	470	553	585	654
Oil/NGL (bbls/d)	17	18	22	15	22	17	23	19
Barrels of oil equivalent (boe/d)	66	85	105	86	100	109	121	128
Average sales prices								
Natural Gas ($/mcf)	3.35	3.84	4.03	3.93	2.15	4.59	4.51	5.19
Oil/NGL ($/bbl)	77.19	69.86	83.45	78.91	66.09	52.69	63.56	67.74
Barrels of oil equivalent ($/boe)	34.79	33.20	36.47	33.33	24.37	31.42	34.13	36.60
Operating costs ($/boe)	17.93	18.01	20.52	18.97	16.32	13.77	15.97	12.51
Royalty Expense ($/boe)	5.44	5.76	3.42	4.38	5.66	5.49	3.60	8.37
Operating netback ($/boe)	11.41	9.43	12.53	9.98	2.39	12.16	14.56	15.72

Explanation of Quarterly Variances

On a quarter by quarter basis production volumes continue to trend downward as prices continue to be significantly lower on a quarter by quarter basis for natural gas prices. Throughout 2010 and 2011 projects were delayed and certain wells were shut in until such time that commodity prices begin to increase. The net loss in the quarters is largely a result of these factors.

Net comprehensive loss increased during the fourth quarter for both the year ended December 31, 2011 and December 31, 2010, primarily due to the impairment of property and equipment taken during both years, and during the year ended December 31, 2011, the impairments taken on the exploration and evaluation assets and the assets held for sale.

The impairments have all been recognized in the fourth quarter.

LIQUIDITY & CAPITAL RESOURCES

On June 23, 2011, the Company amended its revolving operating demand loan (the "Revolving Loan") with a Chartered Canadian Bank (the "Lender"). Pursuant to the amendment, the maximum amount available under the Revolving Loan has been reduced from $3,000,000 to $1,575,000. The per annum interest rate has been increased from the Lender's prime rate plus 2.00% to the Lender's prime rate plus 3.00%. Interest continues to be calculated daily and payable monthly on the outstanding principal amount drawn. At December 31, 2011, the Company had drawn $1,550,000 of the Revolving Loan (December 31, 2010 - $2,875,000).

Also on June 23, 2011, the Company cancelled its existing non-revolving demand loan (the "Non-revolving Loan A") of $400,000 with the Lender and obtained a new non-revolving demand loan (the "Non-revolving Loan B") in the maximum amount of $1,825,000, which was reduced by the Lender on August 15, 2011 to a maximum amount of $1,775,000. The funds received under the Non-revolving Loan B were used to reduce the excess of the Revolving Loan down to the amended maximum and to repay amounts owing under cancelled Non-revolving Loan A. Interest on the Non-revolving Loan B is calculated daily and payable monthly on the outstanding principal amount at a rate per annum equal to the bank's prime rate plus 5.00% (Non-revolving Loan A – bank's prime plus 2.50%). At December 31, 2011 the Company had a remaining balance of $1,125,000 owing.

Under the June 23, 2011 amended agreement, the Company was required to permanently reduce Non-Revolving Loan B by $700,000 on or before July 29, 2011 and the Revolving Loan and Non-revolving Loan B would expire on July 29, 2011, unless further extended by the Lender. The Company failed to permanently reduce Non-revolving Loan B by $700,000 on the stipulated date and further requested the Lender to extend the loans beyond July 29, 2011. On August 15, 2011, a second amending agreement was established between the Lender and the Company, pursuant to which the Lender reduced the maximum amount available under the Non-revolving Loan B to $1,775,000 and that the Company permanently repay and cancel the Non-revolving Loan B by October 14, 2011. During August 2011, the Company fulfilled the requirement to permanently reduce the Non-revolving Loan by $700,000.

Subsequent to December 31, 2011, the Company entered into an additional amending agreement whereby the Company was to reduce the Revolving Loan by $1,500,000 through the sale of certain oil and gas assets, which the Company fulfilled. An amending fee of $10,000 was paid to the Lender, and additionally, a $50,000 amount owing for the previous amendment was also paid to the Lender.

Security for the loans consists of a $10,000,000 Debenture with a floating charge over all assets of the Company with a negative pledge and undertaking to provide fixed charges on the Borrower's major producing petroleum properties at the request of the bank. The bank has required the Company to submit to them certain reports and to maintain certain covenants, including 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 un-drawn availability under the Non-revolving Loan B) to Current Liabilities (excluding any current portion of Bank Debt). As at December 31, 2011, the Company is in violation of the Working Capital Ratio with a ratio of 0.83:1.

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 begun projects and has received 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 prospects should produce better returns due to higher oil prices compared with natural gas, it has greater drilling potential and more locations. Given the Company'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 April 13, 2011 and June 17, 2011, the Company completed a private placement issuing 9,413,701 units and 4,000,000 units, respectively. Each unit was issued at $0.05 for total proceeds of $670,685. Each unit consists of one common share of the Company (issued either as a common share or as a flow through share) and one share purchase 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 original issue date. Of the total 13,413,701 units issued, 7,203,701 were issued as a flow through shares. The Company has allocated $86,967 of the unit value to warrants. Pursuant to the placements, the Company incurred $51,703 in cash share issue costs and issued 470,000 finders options valued at $6,353.

On August 19, 2011, the Company completed a private placement, issuing 4,600,000 units. Each unit was issued at $0.05 for total proceeds of $230,000. Each unit consists of one common share of the Company and one share purchase 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 original issue date. The Company has allocated $29,262 of the unit value to warrants. The Company incurred $28,666 in cash share issue costs.

On August 19, 2011 and October 7, 2011, the Company completed a private placement issuing 4,600,000 units and 1,634,000 units, respectively. Each unit was issued at $0.05 for total proceeds of $311,700. Each unit consists of one common share of the Company and one share purchase 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 original issue date. The Company has allocated $39,677 of the unit value to warrants. The Company incurred $48,866 in cash share issue costs.

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

	April 30, 2012	**December 31, 2011**
Common Shares	97,729,959	83,489,959
Warrants (i)	33,887,701	19,647,701
Stock Options (ii)	7,680,000	7,680,000

Notes:

i) 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. 4,600,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until February 25, 2013. 1,634,000 of the Warrants entitle the holder to acquire one additional common share for $0.10 per share until April 11, 2013.

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. 2,455,000 of the Stock Options entitle the holders to acquire an equal number of common shares at $0.10 per share until April 6, 2015. 4,925,000 of the Stock Options entitle the holders to acquire an equal number of common shares at $0.10 per share until August 25, 2016.

OFF BALANCE SHEET ARRANGEMENTS

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

RELATED PARTIES

Related party transactions not disclosed elsewhere in these financial statements are as follows:

a) The following amounts are due from related parties:

	December 31, 2011 $	December 31, 2010 $
Note receivable from officer (i)	**231,609**	225,054
Fair value allowance (ii)	**(216,515)**	(206,710)
Net note receivable	**15,094**	18,344
Advance fees (iii)	**9,529**	33,029
	24,623	51,373

(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 $15,094 at December 31, 2011 (December 31, 2010 - $19,650).

(ii) The fair value allowance was initially determined on December 31, 2008 based on the market value of the secured shares. During the year ended December 31, 2011, the Company provided an additional allowance of $9,805 to the estimated fair value of the 393,000 common shares held as security as the carrying amount exceeded the fair value (December 31, 2010 - $nil).

(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 December 31, 2011 $9,529 (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. The original repayment date of December 31, 2010 has been extended to December 31, 2012.

b) Additional related party transactions not disclosed elsewhere in these financial statements are as follows:

(i) Aggregate fees of $96,300 (December 31, 2010 - $85,000) were charged by directors of the Company. Of this amount $78,450 (December 31, 2010 - $24,100) was recorded in the statement of comprehensive loss and $17,850 (December 31, 2010 - $60,900) was capitalized to property and equipment.

(ii) Aggregate consulting fees of $179,347 (December 31, 2010 - $256,500) were charged by directors and officers of the Company and were recorded in the statement of comprehensive loss.

(iii) Aggregate fees of $72,275 (December 31, 2010 - $43,200) 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 $53,725 (December 31, 2010 - $43,200) was recorded in the statement of comprehensive loss and $18,550 was capitalized to property and equipment.

(iv) Included in accounts payable at December, 2011 was $37,410 owing to related parties of the Company (December 31, 2010 - $51,636).

Key management compensation

	December 31, 2011	December 31, 2010
	$	$
Compensation	362,912	327,856
Share based payments	60,393	67,872
Total	423,305	395,728

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. Subsequent to December 31, 2011, the Company terminated its existing lease agreement and negotiated a new lease agreement for a smaller office space extending until March 31, 2014 for payments of $2,771 per month.

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 2012 through to 2015 are respectively as follows: $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. During the year ended December 31, 2011, this commitment was fulfilled.

d) The Company is committed to renounce to subscribers $321,998 and $360,185 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. At December 31, 2011, the Company has incurred approximately $88,002 as eligible flow through expenditures against the December 31, 2011 commitment.

SUBSEQUENT EVENTS

Subsequent to December 31, 2011, the Company entered into the following transactions:

a) The Company closed a private placement through the issuance of 14,240,000 units for gross proceeds of $712,000. Each unit consists of one common share of the Company and one share purchase warrant. Each share purchase warrant entitles the holder thereof to purchase 1 additional common share of the Company for a period of 12 months from the issuance of the units at a price of $0.10 per common share. Part of the proceeds from the private placement were used to repay the shareholder loan of $301,157 in its entirety.

b) The Company closed a transaction to sell various interests in certain oil and gas properties to an arm's length party. The total consideration received on the disposition was $1,500,000. The full amount of the proceeds have been used to reduce the Revolving Loan.

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 December 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 $106,642.

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 December 31, 2011, based on the fair market value of the contract, the Company has recorded an unrealized gain in the statement of comprehensive loss of $8,003.

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) Fair values

The Company's financial instruments consist of cash and cash equivalents, short-term investments, trade and other receivables, due from related parties, financial contracts, accounts payable and accrued liabilities, shareholder loan, the bank loan and long-term debt.

Financial Instrument	**Classification**	**Carrying Value $**	**Fair Value $**
Cash and cash equivalents	Fair value through profit and loss	332,301	332,301
Short-term investments	Fair value through profit and loss	49,964	49,964
Trade and other receivables	Loans and receivables	227,231	227,231
Due from related parties	Loans and receivables	24,623	24,623
Shareholder loan	Other financial liabilities	301,157	301,157
Financial contract liability	Fair value through profit and loss	161,770	161,770
Accounts payable and accrued liabilities	Other financial liabilities	2,333,903	2,333,903
Bank loan	Other financial liabilities	2,675,000	2,675,000
Long-term debt	Other financial liabilities	66,580	66,580

The significance of inputs used in making fair value measurements are examined and classified according to a fair value hierarchy. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

At December 31, 2011, the Company's cash has been subject to Level 1 valuation.

(b) 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.

A provision for doubtful accounts of $32,000 has been recorded at December 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.

(c) 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 (as defined by the Bank Loan terms)	$465,104	This amount is anticipated to be met out of additional share issuance in the 2012 and asset sales.
Bank loan and shareholder loan	$2,976,157	Subsequent to December 31, 2011, Company reduced the Revolving Loan by $1,500,000 through the sale of certain oil and gas assets and repaid the shareholder loan in its entirety through a private placement.
Long term debt	$66,580	Vehicle loans will be paid over the next 4 years out of normal cash flow.

(d) 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 fixed the received price of natural gas at CDN 4.684 per GJ.

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 December 31, 2011, based on the fair market value of the contracts, the Company has recorded an unrealized loss of $8,003 (December 31, 2010 - $153,767) in the statement of comprehensive loss.

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

	Option A ($)	**Option B ($)**	**Option C ($)**
Fair market value, January 1, 2010	-	-	-
Unrealized (loss)	162,458	(165,736)	(150,489)
Fair market value, December 31, 2010	162,458	(165,736)	(150,489)
Unrealized (loss)	(162,458)	165,736	(11,281)
Fair market value, December, 2011	-	-	(161,770)
Financial Contract asset (liability):			
Current	(161,770)		

The realized gain recorded by the Company on the derivative financial instruments for the year ended December 31, 2011 was $106,642 (December 31, 2010 – $113,616).

(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 December 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 $37,200 (December 31, 2010 - $5,170) impact on the Company's comprehensive loss for the year.

(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 December 31, 2011 the Company's bank debt was $2,675,000 (December 31, 2010 - $3,275,000). As at December 31, 2011, if interest rates had been 1% higher/lower, with all other variables held constant, there would have been an impact of approximately $29,700 (December 31, 2010 - $29,000) on the Company's comprehensive loss for the year.

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

(e) 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 year.

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

OUTLOOK

Based on the continuation of low natural gas prices, the Company has transitioned its development focus to oil development in both Texas and Alberta. The initial impact of this transition shows a lower production volume in our overall output, but the increases in Oil output are starting to show. The daily production rates in the Company's PRI affiliate is not reported in the Company'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.

The Company 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 year ended December 31, 2011 and, in addition, note 21 and note 22 in the annual 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 and December 31, 2010, and the Statement of Loss and Comprehensive Loss for the year 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 statement of financial position. E&E costs of $223,726 were identified and deemed to be impaired upon transition.

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

The net book value under Canadian GAAP at January 1, 2010 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. The Company determined that an impairment of $120,994 was required upon transition to IFRS.

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 $897,480 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%. This resulted in an increase in the carrying amount of the decommissioning liabilities of $106,206 at January 1, 2010 and $62,548 at December 31, 2010, and a reduction in accretion expense of $958 at December 31, 2010.

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 statement of financial position. At December 31, 2010, $25,081 of undeveloped land and unproven properties were reclassified from property and equipment to E&E.

(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.

(ii) Interest income, interest expense, and foreign exchange gains and losses

Under IFRS interest income, 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. This resulted in a reduction in depletion expense under IFRS during the year ended December 31, 2010 of $84,952.

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 reduction of share-based payment expense under IFRS during the year ended December 31, 2010 of $21,912.

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 of $15,867 in the property and equipment balance at December 31, 2010, with a corresponding charge to deficit.

g) Flow-through shares

The Company has financed a portion of its exploration and development activities through the issuance of flow-through shares. Pursuant to the terms of the flow-through subscription agreements, the tax attributes of the related expenditures are renounced to the subscribers. Under Canadian GAAP, recognition of the foregone tax benefits to the Company is recognized by reducing the carrying value of the shares issued by the amount equal to the tax effect on the expenditures renounced to the subscriber.

Under IFRS, common shares issued on a flow-through basis are recorded at the fair value, excluding any premium to the current market price. The premium is recorded as a current liability and when expenses are incurred, the Company derecognizes the liability and recognizes a deferred tax liability for the amount of the tax reduction renounced to the shareholders. The premium is recognized as other income and the related deferred tax is recognized as a tax provision. As a result of the differences in accounting for flow-through shares, at January 1, 2010 and December 31, 2010, the Company increased its deficit and its share capital by $831,000 and $984,750, respectively.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the 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 CGUs 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 accounting policy for exploration and evaluation assets is described in note 3. The application of this 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, the forfeiture rate, the interest rate and the expected term of the issued stock option.

Deferred 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 and will become effective beginning on or after January 1, 2013:

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.

IFRS 10 – "Consolidated Financial Statements", which builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.

IFRS 11 – "Joint Arrangements", which establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.

IFRS 12 – "Disclosure of Interest in Other Entities", which provides the disclosure requirements for interests held in other entitles including joint arrangements, associates, special purpose entities and other off balance sheet entities.

IFRS 13 – "Fair Value Measurement", which defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.

IAS 27 – "Separate Financial Statements", which provides amendments to IAS 27 to coincide with the changes made in IFRS 10, but retains the current guidance for separate financial statements.

IAS 28 – "Investments in Associate and Joint Ventures", which revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

IFRS 7 – "Financial Instruments: Disclosures" and IAS 32 "Financial Instruments: Presentation", provides amendments to the previously issued IFRS 7 "Financial Instruments: Disclosures" and IAS 32 "Instruments: Presentation", to provide clarity over the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 are effective on January 1, 2013 with required retrospective application and early adoption permitted. Amendments to IAS 32 are effective on January 1, 2014 with required retrospective application and early adoption permitted.

IAS 1 – "Presentations of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements", which provides stipulates for the amendment of the presentation of net earnings and OCI and also requires that items are grouped within OCI based on whether the items may be subsequently reclassified to profit or loss. Amendments to IAS 1 are effective for the Company beginning on January 1, 2012 with retrospective application and early adoption permitted.