EAGLEWOOD ENERGY

Eaglewood Energy Inc.
Management's discussion and analysis
For the three and six months ended June 30, 2011 and 2010

Chief Executive's message

The Company's second quarter was relatively quiet as our attention was focused on acquiring regulatory approvals on our licenses. With the Ubuntu discovery, our original license commitment required an appraisal well. As only one zone of the Ubuntu well is capable of production, an appraisal well is not warranted at this time without additional seismic to determine the optimal way to develop the field. We have applied for a variation to the original terms of the license to replace the requirement for an appraisal well with additional seismic and geological work over the Ubuntu discovery. This variation has been approved by the Petroleum Advisory Board ("PAB") and is awaiting a signature on the formal instrument from the Minister for Petroleum and Energy (the "Minister"). The seismic acquisition program over the Ubuntu discovery has been initiated and will be completed once the Minister has signed the instrument.

During the second quarter the last of our licenses' original term expired so we are now into the relinquish and extension phase for all of our licenses. Under PNG regulations, after the original six year term expires, if the license is in good standing the licensee can apply for a five year extension and is required to relinquish 50% of the original license area. We have submitted our relinquishment areas and applications for extension on the three licenses we operate, namely PPL 257, 258 and 259, and the operator of PPL 260 has submitted the required documentation for that license. For licenses not in compliance with the terms of the original work commitment, the licensee must apply for a variation of the original terms. All variations and extensions must be approved by the PAB and once the PAB minutes are prepared the official instrument must be signed by the Minister. The Company currently has variation applications for 259 approved by the PAB and PPL 257 variation reviewed by the DPE and recommended for approval by the PAB. These approvals are awaiting formal approval by the Minister. The PAB did not approve the extension of our PPL 258 license, but left it to the Minister's discretion whether or not to approve the extension. This decision has been pending for over a year with no resolution, so the Company's board has decided to write it down as an impaired asset in these second quarter financials.

The final item awaiting regulatory approval is the awarding of Petroleum Retention License ("PRL") status to the two blocks containing the Ubuntu discovery. The application for PRL 28 has been reviewed by the DPE and recommended for approval to the PAB and will then require the Minister's signature on the official instrument.

Acquiring Ministerial signatures in PNG can take a long time in the best circumstances, but has been particularly challenging recently with some sudden changes in the PNG political landscape as several members of the then ruling party crossed the floor to join an opposition party that formed a government by majority vote.

We expect that we will receive the official instruments validating our extensions, which are required in order to complete farmouts with industry parties to further the realization of our licenses' potential. Once we receive the required approvals, we look forward to a much more active second half of the year.

As always, we thank all our shareholders for their support and patience through this difficult year.

Brad Hurtubise
Chief Executive Officer

Management's discussion and analysis ("MD&A") of Eaglewood Energy Inc.'s (the "Company" or "Eaglewood") financial condition and results of operations should be read in conjunction with the consolidated financial statements for the three and six months ended June 30, 2011 and 2010 and related notes therein prepared in accordance with International Financial Reporting Standards. The effective date of this MD&A is August 22, 2011.

Additional information relating to the Company is available on SEDAR at www.sedar.com and the Company's website at www.eaglewoodenergy.ca .

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A may constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements, other than statements of historical fact, may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "propose", "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. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon as actual results may vary. These statements speak only as of the date of this MD&A and are expressly qualified, in their entirety, by this cautionary statement.

In particular, this MD&A contains forward-looking statements, pertaining to the following:

- capital expenditure programs;
- development of resources;
- treatment under governmental regulatory and taxation regimes;
- expectations regarding the Company's ability to raise capital;
- expenditures to be made by the Company to meet certain work commitments; and
- work plans to be conducted by the Company.

With respect to forward-looking statements listed above and contained in this MD&A, the Company has made assumptions regarding, among other things:

- the Papua New Guinea legislative and regulatory environment;
- the impact of increasing competition;
- unpredictable changes to the market prices for oil and natural gas;
- that costs related to development of the oil and gas properties in Papua New Guinea will remain consistent with historical experiences;
- anticipated results of exploration activities;
- availability of additional financing and farm-in or joint venture partners; and
- the Company's ability to obtain additional financing in a timely manner and on satisfactory terms.

The Company's 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:

- volatility in the market prices for oil and natural gas;
- uncertainties associated with estimating resources;
- geological, technical, drilling and processing problems;
- liabilities and risks, including environmental liabilities and risks, inherent in oil and natural gas operations;
- fluctuations in currency and interest rates;
- incorrect assessments of the value of acquisitions;
- unanticipated results of exploration activities;
- competition for, among other things, capital, acquisitions of reserves, equipment, undeveloped lands and skilled personnel;
- lack of availability of additional financing and farm-in or joint venture partners;
- unpredictable weather conditions; and
- other factors referred to under "Risk Factors" in the Company's annual information form for the year ended December 31, 2010, dated April 14, 2010 and filed on SEDAR on April 19, 2011.

Undue reliance should not be placed on forward-looking statements as the plans, intentions or expectations upon which they are based might not occur. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. The Company does not undertake any obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by law.

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

Eaglewood's interim consolidated financial statements and the financial data included in the interim MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC") that are effective or available for early adoption by the Company as at December 31, 2011, the date of the Company's first annual reporting under IFRS. The adoption of IFRs does not impact the underlying economics of Eaglewood's operations or its cash flows.

Note 15 to the Company's interim consolidated financial statements contains a detailed description of the Company's adoption of IFRS, including a reconciliation of the consolidated financial statements previously prepared under Canadian GAAP to those under IFRS for the following:

- The Consolidated Balance Sheet at January 1, 2010 and at December 31, 2010; and
- The Consolidated Statement of Loss and Comprehensive Loss for the three and six month periods ended June 30, 2010 and the year ended December 31, 2010.

The most significant impacts of the adoption of IFRS, together with details of the IFRS 1 exemptions taken, are described in the IFRS FIRST TIME ADOPTION section of this interim MD&A.

Comparative information has been restated to comply with IFRS requirements, unless otherwise indicated.

COMPANY OVERVIEW

Eaglewood is an international, junior oil and gas company which trades on the TSX Venture Exchange (trading symbol "EWD"). The Company's primary activity is exploration and development of its three remaining petroleum prospecting licenses located in Papua New Guinea (the "PNG Licenses") which were acquired in October 2007. The Company has no oil and gas properties other than the PNG Licenses. Currently there is no production or reserves associated with the PNG Licenses.

EVENTS IN Q2:2011

On April 18, 2011, the Company completed the demobilization of Rig 103.

During the six months ended June 30, 2011, the Company recorded impairment of $1.4M related to PPL 258. On March 18, 2010, the Company submitted a request for a five year extension of the license upon its expiry in October 2010. The Petroleum Advisory Board ("PAB") deliberated on the extension application but did not make a recommendation on extension of the license. Final approval/denial was left to the discretion of the Energy Minister, which has not been received to date. Based on the time elapsed without a decision, the Company has decided to impair the asset.

SUBSEQUENT EVENTS

On July 25, 2011 the Company announced that it has received direction from the PNG Department of Petroleum and Energy ("DPE") and have commenced negotiations with the Petroleum Retention License 4 ("PRL 4") Joint Venture to unitize the Stanley Hydrocarbon Pool within PRL 4 with graticular block 1622 in the Corporation's Petroleum Prospecting License 259 ("PPL 259"), in Papua New Guinea. Recent mapping presented by the operator of PRL 4 indicates that a connected portion of the Stanley petroleum pool at Toro Reservoir level extends beyond PRL 4 and into Eaglewood's PPL 259, specifically graticular block 1622 in the northwest corner of the license. This interpretation is consistent with the Corporation's ongoing mapping studies. A development license cannot be issued to PRL 4 until this issue is resolved to the satisfaction of the DPE.

DESCRIPTION OF PNG LICENSES AND COMMITMENTS

Each of the PNG Licenses gives the Company the right to explore for oil and natural gas on specified blocks in PNG. If exploration is successful, the Company can apply to the PNG government for either a retention license or a development license. A retention license is generally applied for if natural gas reserves have been identified but additional time is required to either prepare a development plan or, if the amount of natural gas reserves is not of a sufficient commercial quantity, to explore for further natural gas reserves. A development license is generally applied for if oil and/or natural gas reserves have been discovered and production is commercially viable. The PNG government has historically granted retention or development licenses however there is a risk that a retention or development license may not be granted to the Company when, or on the terms, applied for.

PPL 259

Originally granted on June 30, 2005, PPL 259 has a six year term that expired on June 29, 2011. It covers 1,377,000 gross acres, all onshore, in the foreland region of the Papuan Fold Belt of PNG. PPL 259 is a natural gas and natural gas liquids play for the Company. The Company has a 90 percent participating interest in PPL 259 excluding two graticular blocks within the license area surrounding the Ubuntu prospect. A 10 percent participating interest in PPL 259 was farmed-out in 2009. In November 2010, the Company farmed-out a 50 percent interest in two graticular blocks surrounding the Ubuntu prospect (representing approximately 3 percent of the license and approximately 6 percent of the license after relinquishment (see note 13 of the financial statements)) reducing the Company's share of Ubuntu-1 to 40 percent.

There was a commitment to drill an exploration well on the license. On September 21, 2010 the Minister for Petroleum and Energy approved a variation to the drilling commitment moving it to 2010. Drilling of the Ubuntu-1 well commenced in December 2010. On February 7, 2011, Eaglewood announced that it was suspending the Ubuntu-1 well as a gas and gas condensate discovery. On February 11, 2011, Eaglewood further announced that wireline logging and data acquisition programs had been completed in Ubuntu-1 including the recovery of down-hole hydrocarbon samples and sidewall cores. The estimated gross cost of the well was approximately US $43,500,000 (Company share 40 percent, net cost approximately US $17,400,000).

On April 28, 2011, the Company announced the results of a report of estimated resources on the Ubuntu-1 well.

In the event of a discovery there is a requirement to drill an appraisal well by June 30, 2011. An appraisal well is not currently warranted until further seismic is acquired. On March 7, 2011 a variation application was submitted to the Department of Petroleum and Energy requesting the requirement to drill an appraisal well is replaced by a seismic acquisition programme and further geological studies.

On March 29, 2011, the Company submitted to the Department of Petroleum and Energy of PNG, an application for a five year extension on the PPL 259 license. The PAB has reviewed the variation and extension applications and recommended approval. Under the PNG Oil and Gas Act, the license is deemed to still be in effect until formal approval of the extension is granted by the Energy Minister. In accordance with the terms of the license renewal, 50 percent of the area for PPL 259 will be relinquished when, and if, the extension is granted. The Company expects that the PPL 259 license will be extended and that the appraisal well drilling commitment will be replaced with the seismic programme.

PPL 260

Originally granted on March 14, 2005, PPL 260 has a six year term that was due to expire on March 13, 2011. It covers 1,559,250 gross acres, all onshore, in the highland region of the Papuan Fold Belt of PNG. PPL 260 is an anticipated natural gas and natural gas liquids play for the Company. The Company has a 30 percent participating interest in PPL 260. In 2009, the Company farmed-out a 70 percent participating interest. The farmee assumed operatorship in 2009.

There was a commitment to drill one exploration well by March 13, 2010. Pre-drilling activities for the first exploration well, Korka-1, began in March and drilling was underway during April 2010. Unfortunately, the exploration well encountered no hydrocarbons and was plugged and abandoned. Location and timing decisions for a second exploration well are being evaluated.

In December 2010, the Operator of the license submitted a request for a five year extension of the license upon its expiry in March 2011. The PAB has reviewed the extension application and recommended approval. Under the PNG Oil and Gas Act, the license is deemed to still be in effect until the formal approval of the extension is granted by the Energy Minister. In accordance with the terms of the license renewal, 50 percent of the area for PPL 260 will be relinquished when, and if, the extension is granted. The area to be relinquished was determined by the Operator after an extensive review of seismic and aero/gravity magnetic surveys done on the license. The Company expects that the PPL 260 license will be extended.

PPL 257

Originally granted on October 20, 2004, PPL 257 had an initial six year term that was due to expire on October 19, 2010. Under the PNG Oil and Gas Act, the license is deemed to still be in effect while the Company awaits review of its extension request by the Minister. PPL 257 currently covers 1,741,500 gross acres located in the Cape Vogel Basin of PNG. The prospective area is predominantly offshore but includes an onshore area that will be instrumental for conducting geological field work. PPL 257 is an anticipated natural gas play for the Company. The Company holds a 100 percent participating interest in PPL 257. There was a commitment to drill one exploration well by October 20, 2009 under the initial term of the license that was not met. However, the Company met the other commitments under the license including seismic acquisition. The Company estimates that the cost of drilling one exploration well is approximately US $60,000,000.

On March 18, 2010, the Company submitted a request for a variation of the drilling commitment and a five year extension to the license upon its expiry in October 2010. The PAB has reviewed the variation and extension applications and recommended approval of both. In accordance with the terms of a license extension, the Company will relinquish 50 percent of the area for PPL 257 when, and if, the extension is approved by the PNG government. The area to be relinquished was determined by the Company after an extensive review of seismic and aero/gravity magnetic surveys done on the license. The Company expects that PPL 257 will be extended and that the previous drilling commitment will be added to future work commitments.

PPL 258

Originally granted on October 20, 2004, PPL 258 had an initial a six year term that was due to expire on October 19, 2010. On March 18, 2010, the Company submitted a request for a five year extension of the license upon its expiry in October 2010. Under the PNG Oil and Gas Act, the license is deemed to still be in effect while the Company awaits review of its extension request by the Minister. The PAB deliberated on the extension application but did not make a recommendation on extension of the license. Final approval/denial was left to the discretion of the Energy Minister, which has not been received to date. Based on the lack of a positive recommendation from the PAB, the Company decided to impair this asset.

The PNG government retains the right to back-in for up to a 22.5 percent interest at cost which can be exercised at the time a development license is granted. The PNG government also has a two percent royalty over any oil or natural gas production that may occur with respect to the PNG Licenses.

Pursuant to the acquisition of the PNG Licenses, the Company granted the original vendor the right to acquire a 10 percent interest in all, but not less than all, of the PNG Licenses, exercisable within 60 days from the date which the Company completes the drilling and testing of a third well on the PNG Licenses by paying to the Company 10 percent of all costs incurred in respect of the PNG Licenses up to that date and by agreeing to pay 10 percent of the ongoing costs with respect to the exploration and development of the PNG Licenses.

The Company has issued bank guarantees totaling approximately $160,000 (100,000 Papua New Guinea dollars for each license) as security against the capital requirements associated with the PNG Licenses. If the Company does not fulfill its commitments under a PNG License and has not applied for and been granted an extension, it could potentially lose its guarantee and the applicable PNG License could be revoked by the PNG government.

As the Company does not currently generate sufficient cash flow from operating activities to fund its activities, it will need to raise equity financing and/or enter into joint venture or farm-out arrangements to finance its exploration commitments for the PNG Licenses.

SELECTED QUARTERLY INFORMATION

The following is a summary of selected financial information for the Company for the periods indicated:

($000's except per share data)	Jun 30 2011	Mar 31 2011	Dec 31 2010	Sep 30 2010	Jun 30 2010	Mar 31 2010	Dec 31 2009(1)	Sep 30 2009(1)
Revenue	-	-	-	-	-	-	2	-
Loss before discontinued operations	2,577	632	347	799	886	101	1,311	818
Net loss	2,577	632	347	799	886	101	1,311	818
Loss per share before discontinued operations	0.03	0.01	0.01	0.01	0.01	0.01	0.03	0.01
Total loss per share	0.03	0.01	0.01	0.01	0.01	0.01	0.03	0.01
Total assets	62,202	66,585	72,202	56,900	55,714	53,790	30,488	32,178

(1) As the Company's transition date was January 1, 2010, the quarterly financial information for 2009 has not been restated.

- The Company currently has no oil or gas production to offset its expenses. The Company's expenses are described more fully in RESULTS OF OPERATIONS.
- The Company's main assets are petroleum and natural gas properties and cash.

RESULTS OF OPERATIONS

The Company had a net loss of $2,576,698 and 3,208,307 for the three and six months ended June 30, 2011 compared to a net loss of $886,248 and $987,316 for the three and six months ended June 30, 2010.

Total expenses from operating activities for the three and six months ended June 30, 2011 were $2,413,124 and $3,109,832 compared to $967,662 and $1,881,357 for the three and six months ended June 30, 2010.

For the three and six months ended June 30, 2011 the Company recorded an impairment expense of $1,402,317 (June 30, 2010 – nil), related to PPL 258. On March 18, 2010, the Company submitted a request for a five year extension of the license upon its expiry in October 2010. The PAB deliberated on the extension application but did not make a recommendation on extension of the license. Final approval/denial was left to the discretion of the Energy Minister, which has not been received to date. Based on the time elapsed without a decision, the Company decided to impair this asset.

The following table provides a breakdown of the Company's general and administrative ("G&A") expenses by material component:

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
Salaries & wages	**$ 338,242**	$ 329,211	**$ 693,138**	$ 697,590
Stock based compensation	**305,234**	282,905	**529,858**	518,342
Travel & accommodation	**62,101**	129,759	**175,037**	189,263
Professional fees	**123,916**	48,275	**164,517**	80,227
Office costs	**78,370**	118,624	**147,270**	163,263
Public company	**55,024**	25,280	**92,315**	137,177
Office rent	**24,306**	39,938	**45,995**	67,492
Other general and administrative	**27,764**	33,553	**79,574**	63,053
Overhead recoveries	**(44,118)**	(45,977)	**(299,076)**	(45,977)
	$ 970,839	$ 961,568	**$ 1,628,628**	$ 1,870,430

The G&A expenses for the six months ended June 30, 2011 are approximately $242,000 lower than the expenses for the six months ended June 30, 2010. For the three months ended June 30, 2011, the G&A expenses are approximately $9,000 higher than for the same period in 2010. For the six months ended June 30, 2011, overhead recoveries were approximately $253,000 higher than for the six months ended June 30, 2011. Overhead recoveries are a function of joint operations. Pursuant to the Joint Operating Agreement for PPL 259, Company recovers a percentage of the capital expenditures as compensation for the indirect services provided to the Joint Venture. For the three months ended June 30, 2011, the Company's overhead recoveries were comparable to the same period in 2010, but due to drilling activities in Q1:2011, for the six months ended June 30, 2011, overhead recoveries were much higher than for the same period in 2010.

Travel costs for the three months ended June 30, 2011 are approximately $67,000 lower than for the same period in 2010, while for the six months ended June 30, 2011, travel costs are only $14,000 lower than for the six months ended June 30, 2010. The timing of travel is dependant on operational activity, but is relatively consistent year over year.

Professional fees for the three and six months ended June 30, 2011 are $75,000 and $84,000 higher than for the three and six months ended June 30, 2010. This increase in fees is related to the transition to IFRS effective January 1, 2011.

Public company costs for the three months ended June 30, 2011 are approximately $30,000 higher than for the three months ended June 30, 2010, while year-to-date, public company costs are $45,000 lower than for the same period in 2010. The AGM in 2011 was held in June while in 2010 the AGM was held in April. As a result, costs related to the AGM such as printing and SEDAR filing were recorded in Q2 in 2011 versus Q1 in 2010. Also in March 2010, the Company incurred approximately $70,000 in costs for the filing of a short-form prospectus.

Other general and administrative costs were approximately $16,000 higher in 2011 versus 2010. Other general and administrative costs includes conference fees, for which $14,000 was incurred for the Small/Mid Scale LNG conference.

FINANCIAL CONDITION

At June 30, 2011, the Company had total assets of $62.2 million compared to $72.2 at December 31, 2010. The decrease in assets was mainly due to the decrease in amounts outstanding as accounts receivable. As the drilling program on the Ubuntu prospect and the demobilization of rig were completed in the six months ended June 30, 2011 and credits outstanding on the Korka well were paid, the amounts outstanding from Joint Venture partners decreased by $7.9 million.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2011, the Company had net working capital of $5.1 million compared to net working capital of $15.5 million at December 31, 2010.

The decrease in working capital is mainly due to the use of cash for operations and the drilling program. Funds used in operations for the six months ended June 30, 2011 were $1,164,603, which was offset by the an increase in working capital of $1,309,115. The change in working capital is related to a decrease in accounts receivable of $8.1 million and a decrease in accounts payable of $6.8 million.

Funds used in investing activities for the six months ended June 30, 2011 were $8,192,630. Funds used for the addition of exploration and evaluation assets totaled $9.5 million, which was funded in part by the release of a portion of the letter of credit, which contributed $1.3 million to cash and cash equivalents.

A summary of capital expenditures for the first three months of 2011 is provided below.

PPL 259 – Seismic program	$ 3,316,814
PPL 259 – Rig demobilization	3,056,754
PPL 259 – Ubuntu-1 exploration well	2,951,385
Overhead	183,888
PPL 260 – Operator overhead	17,524
PPL 259 – FEED study	12,723
Other	12,270
PPL 260 – Korka-1 exploration well	(75,151)
Total exploration and evaluation assets	9,476,207
Office equipment, furniture, computer equipment	21,742
Total capital expenditures	$ 9,497,949

For the six months ended June 30, 2011, the Company received $498,136 (net of costs) for the issuance of shares from the over-allotment option pursuant to the December 2010 equity financing and from the exercise of options.

The effect of exchange rates on cash and cash equivalents was $(261,693).

The Company does not currently generate sufficient cash flow from its operating activities to fund its activities and has relied upon contributions from farm-outs and the issuance of equity to provide additional funding. The Company's financial statements are presented on a going-concern basis which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of operations. The Company's ability to continue as a going concern is dependent upon its ability to raise equity financing and/or enter into joint venture or farm-out arrangements in the PNG Licenses within the next twelve months to meet its exploration commitments and working capital requirements. Management believes there is the opportunity for the Company to enter into further farm-out or joint venture arrangements and/or raise further equity in 2011/2012 and therefore continue as a going concern. However, there are no assurances that the Company will be successful in achieving these objectives. If the Company is unable to raise equity financing and/or secure farm-out or joint venture partners, the Company may be unable to continue as a going concern. The Company's financial statements do not reflect the adjustments to the carrying values of assets and liabilities, including any impairment in its petroleum and natural gas properties, and the reported expenses and balance sheet classifications that would be necessary if the Company is unable to continue as a going concern, and such adjustments could be material.

2011 WORK PROGRAM AND OUTLOOK

2011 Work Program
The Company's 2011 work program is primarily based on meeting its PNG License commitments which includes gathering appraisal data on the Ubuntu Discovery in PPL 259. The Company is in discussions with industry partners to enter into further joint venture or farm-out arrangements in the PNG Licenses.

PPL 259 Work Program
On September 21, 2010, the Minister for Petroleum and Energy granted the Company a variation to the original drilling commitment for PPL 259 from 2009 to 2010. Ubuntu-1 was expected to spud in August 2010 but due to delays in mobilization of the drilling rig caused by weather, barge scheduling and helicopter operations, the actual spud date was December 12, 2010.

Ubuntu-1 was suspended on February 17, 2011 as a gas and gas condensate discovery. The Company is currently undertaking studies on the discovery with a view to recommending an appraisal Work Program & Budget to the PNG Department of Petroleum and Energy. The Company holds a 40 percent participating interest in Ubuntu-1. The rig was fully demobilized from the Ubuntu wellsite on April 18, 2011.

The second planned exploration well in PPL 259, Herea-1, has been postponed, pending a reserves revision following the discovery of significantly thicker than anticipated net pay on Stanley-2, an appraisal well drilled in the adjacent PRL-4 license. The Company is currently seeking additional farm-out or joint venture partners to reduce its net interest and share of costs for Herea-1. Assuming a successful farm-out of the prospect, the Operator plans to acquire prospect infill seismic in Q3 2011 and begin pad construction in Q4 2011.

The Company acquired additional seismic in PPL 259 during January and February of 2011, at an estimated gross cost of US $3,220,000 (net cost to the Company approximately US $2,900,000). Processing and interpretation of the new seismic data, along with reprocessing of 570 line km of vintage seismic was completed in March 2011. The Company has completed a front end engineering ("FEED") study for the rapid commercialization of PPL 259 via condensate stripping followed by a small scale liquified natural gas project, and is awaiting a final report. The estimated gross cost of the FEED study is expected to be approximately US $4,500,000.

PPL 257

For PPL 257, the Company has applied to the PNG government for a five-year extension to the license. The license was due to expire in October 2010, however, it remains valid while the extension request await formal approval by the Energy Minister (SEE DESCRIPTION OF PNG LICENSES AND COMMITMENTS). The Company continues to discuss farm-out/joint venture arrangements with partners for this license. Offers are being reviewed and a work program will be agreed with the successful farmee for an equity position.

PPL 260

During the second quarter of 2010, the first exploration well, Korka-1, was drilled in PPL 260. Unfortunately, the well did not encounter hydrocarbons and was plugged and abandoned. The gross cost of drilling Korka-1 was approximately US $57,000,000 (net cost to the Company approximately US $6,600,000). The current 6 year term of the license was due to expire in March 2011. In December 2010, the operator, Oil Search (PNG) Ltd., submitted an application for a 5 year extension which requires relinquishment of 50% of the graticular blocks within the license. The license remains valid while the extension request awaits review by the Minister (SEE DESCRIPTION OF PNG LICENSES AND COMMITMENTS). The most prospective part of the license will be retained and a work program submitted. The program for years 1 and 2 comprise surface geological studies to high grade the most prospective areas. This work will be completed in 2011 and 2012 and Eaglewood's share of costs will not exceed US$ 300,000.

As a result of the nature of the petroleum and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while it is currently intended by management of the Company that the general expenditures set out in the work program above will be made by the Company, actual expenditures may in fact differ from these plans, amounts and allocations.

Additionally, completion of activities are subject to potential barriers such as, but not limited to, lack of capital, lack of available equipment and poor weather which may impact the timing of completion. Additional risk factors are disclosed in the Company's Annual Information Form dated April 14, 2011 which is available on SEDAR at www.sedar.com.

OUTSTANDING SHARE DATA

As at August 22, 2011, the Company had 87,148,942 common shares outstanding and 5,846,000 stock options outstanding under its stock option plan. The Company also had 7,800,000 performance warrants outstanding.

RELATED PARTY TRANSACTIONS

For the three and six months ended June 30, 2011, the Company paid $35,738 and $53,986 for legal services to a firm of which an officer of the Company is a partner.

For the three and six months ended June 30, 2011, the Company paid $3,000 and $6,000 in management fees to a company controlled by a director. These fees were paid for administrative services which were provided by the director.

Key management personnel compensation

In addition to their salaries, the Company also provides non-cash benefits to executive officers. The executive officers include the Chief Executive Officer, the Chief Operating Officer and the Chief Financial Officer. Executive officers also participate in the Company's stock option program. Key management personnel compensation for the three and six months ended June 30, is comprised as follows:

	For the three months ended,		For the six months ended,	
	June 30, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
Salaries and wages	**$ 200,780**	$ 205,128	**$ 531,462**	$ 413,174
Short-term employee benefits	**2,838**	2,475	**11,966**	11,188
Share-based payments	**49,995**	70,124	**96,586**	146,711
	$ 253,613	$ 277,727	**$ 640,014**	$ 571,073

FINANCIAL INSTRUMENTS AND OTHER INSTRUMENTS

The Company's financial instruments consist of cash and cash equivalents, accounts receivable and accounts payable. Unless otherwise noted, it is management's opinion that the Company is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of these financial instruments approximate their carrying values, unless otherwise noted.

IFRS FIRST TIME ADOPTION

Eaglewood's interim consolidated financial statements as at and for the three and six months ended June 30, 2011 have been prepared in accordance with IFRS as issued by the IASB. Previously, the Company prepared its annual and interim consolidated financial statements in accordance with Canadian GAAP. Since the interim consolidated financial statements represent the Company's initial presentation of its results and financial position under IFRS, they have been prepared in accordance with International Accounting Standards ("IAS") 34 - *Interim Financial Reporting* and IFRS 1 - *First Time Adoption of IFRS*.

The Company's significant accounting policies under IFRS are described in note 3 to the interim consolidated financial statements.

The Company has applied the following transition exceptions and exemptions to full retrospective application of IFRS:

IFRS 1 election for full cost oil and gas entities:
The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows: exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP.

IFRS 1 election for share-based payments:
The Company elected an IFRS 1 exemption relating to fully vested stock options at January 1, 2010 whereby the Canadian GAAP balances relating to fully vested stock options at January 1, 2010 have been carried forward without adjustment. Full retrospective application of IFRS has been applied to unvested stock options at January 1, 2010.

The other significant differences between IFRS and Canadian GAAP, are summarized as follows:

(a) *Share - based payments:*
Under Canadian GAAP, the Company did not incorporate a forfeiture estimate in determining the fair value of share options and performance warrants. Under IFRS, the Company must estimate a forfeiture rate. Also, under IFRS for performance warrants, the Company estimates the probability of achieving certain share prices in determining the fair value of the warrants.

(b) *Foreign currency:*
The Company has determined that US dollars and Canadian dollars are the functional and presentation currencies, respectively, for IFRS financial statements. The impact arising from this change has been included in the above reconciliations. The most significant impact on the balance sheet is an increase in exploration and evaluation assets and property, plant and equipment of $2,326,774 with an offsetting decrease in the deficit as at January 1, 2010 (June 30, 2010 - increase in exploration and evaluation assets and property, plant and equipment of $2,499,840 and the same decrease in the deficit; December 31, 2010: increase in exploration and evaluation assets and property, plant and equipment of $1,233,156 and an offsetting decrease in the deficit). The impact of the accumulated other comprehensive income is an decrease in other comprehensive income of $591 for the six months ended June 30, 2010 (January 1, 2010 - nil; year ended December 31, 2010 – increase of $593,516). The impact of the profit or loss is a decrease in foreign currency exchange gain of $785,103 for the three months ended June 30, 2010 and an increase in foreign currency exchange gain of $378,895 for the six months ended June 30, 2010 (year ended December 31, 2010 - $1,028,795).

(c) Reclassifications
The Company has reclassified its consolidated statement of comprehensive income in order to conform to IFRS.

(d) Asset retirement obligations
Consistent with IFRS, asset retirement obligations have been previously measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under IAS 37, asset retirement obligations are discounted using a risk-free rate, whereas they were discounted using a credit-adjusted rate under Canadian GAAP.

NEW AND AMENDED ACCOUNTING STANDARDS

(a) New accounting standards

IFRS 9 was issued in November 2009 and contained requirements for financial assets. This standard addresses classification and measurement of financial assets and replaces the multiple category and measurement models in IAS 39 for debt instruments with a new mixed measurement model having only two categories: amortized cost and fair value through profit or loss. IFRS 9 also replaces the models for measuring equity instruments, and such instruments are either recognized at fair value through profit or loss or at fair value through other comprehensive income. Where such equity instruments are measured at fair value through other comprehensive income, dividends are recognized in profit or loss to the extent not clearly representing a return of investment, are recognized in profit or loss; however, other gains and losses (including impairments) associated with such instruments remain in accumulated comprehensive income indefinitely.

Requirements for financial liabilities were added in October 2010 and they largely carried forward existing requirements in IAS 39, Financial Instruments – Recognition and Measurement, except that fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

This standard is required to be applied for accounting periods beginning on or after January 1, 2013, with earlier adoption permitted. The Company has not yet assessed the impact of the standard or determined whether it will adopt the standard early.

In May 2011, the IASB issued the following standards which have not yet been adopted by the Company: IFRS 11, *Joint Arrangements* (IFRS 11), IAS 27, *Separate Financial Statements* (IAS 27), IFRS 13, *Fair Value Measurement* (IFRS 13) and amended IAS 28, *Investments in Associates and Joint Ventures* (IAS 28). Each of the new standards is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company has not yet begun the process of assessing the impact that the new and amended standards will have on its financial statements or whether to early adopt any of the new requirements.

The following is a brief summary of the new standards:

IFRS 11 - *Joint Arrangements* requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, *Interests in Joint Ventures,* and SIC-13, *Jointly Controlled Entities—Non-monetary Contributions by Venturers*.

IFRS 13 - *Fair Value Measurement* is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosure requirements for fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

(b) Amendments to Other Standards

In addition, there have been amendments to existing standards, including IAS 27, *Separate Financial Statements* (IAS 27), and IAS 28, *Investments in Associates and Joint Ventures* (IAS 28). IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13.

ADDITIONAL DISCLOSURE FOR VENTURE ISSUERS WITHOUT SIGNIFICANT REVENUE

The Company is a venture issuer that has not had significant revenue from operations in either of its last two financial years. In accordance with National Instrument 51-102, additional disclosure on material costs is presented below.

	Three months ended June 30,		**Six months ended June 30,**	
	2011	2010	**2011**	2010
Salaries & wages	**$ 338,242**	$ 329,211	**$ 693,138**	$ 697,590
Stock based compensation	**305,234**	282,905	**529,858**	518,342
Travel & accommodation	**62,101**	129,759	**175,037**	189,263
Professional fees	**123,916**	48,275	**164,517**	80,227
Office costs	**78,370**	118,624	**147,270**	163,263
Public company	**55,024**	25,280	**92,315**	137,177
Office rent	**24,306**	39,938	**45,995**	67,492
Other general and administrative	**27,764**	33,553	**79,574**	63,053
Overhead recoveries	**(44,118)**	(45,977)	**(299,076)**	(45,977)
Total general and administrative	**$ 970,839**	$ 961,568	**$ 1,628,628**	$ 1,870,430
Capitalized exploration and evaluation costs	**$2,995,816**	$10,044,174	**$9,497,949**	$11,640,237