MANAGEMENT DISCUSSION FOR ARCTIC HUNTER ENERGY INC.
FOR THE PERIOD ENDED DECEMBER 31, 2012
PREPARED AS OF FEBRUARY 22, 2013

Contact Information

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This management's discussion and analysis provides an analysis of our financial situation which will enable the reader to evaluate important variations in our financial situation for the six month period ended December 31, 2012 as compared to the six month period ended December 31, 2011. This report supplements our condensed financial statements for the six month period ended December 31, 2012 and should be read in conjunction with our financial statements and the accompanying notes. Our financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS") and all monetary values included in this report are in Canadian dollars, unless it is indicated otherwise. Our financial statements and the management's discussion and analysis are intended to provide a reasonable base for the investor to evaluate our financial situation.

Additional information regarding the Company is available on SEDAR at www.sedar.com.

Forward-Looking Statements

The matters discussed in this MD&A include certain forward-looking statements. Forward-looking statements include, without limitation, any statement that may predict, forecast, indicate or imply future results, performance or achievements. Forward-looking statements may be identified, without limitation, by the use of such words as "anticipates", "estimates", "expects", "intends", "plans", "predicts", "projects", "believes", or words or phrases of similar meaning. In addition, any statement that may be made concerning future performance, strategies or prospects and possible future corporate action, is also a forward-looking statement. Forward-looking statements are based on current expectations and projections about future general economic, political and relevant market factors, such as interest rates, foreign exchange rates, equity and capital markets, and the general business environment, in each case assuming no changes to applicable tax or other laws or government regulation. Expectations and projections about future events are inherently subject to, among other things, risks and uncertainties, some of which may be unforeseeable. Accordingly, assumptions concerning future economic and other factors may prove to be incorrect at a future date. Forward-looking statements are not guarantees of future performance, and actual events could differ materially from those expressed or implied in any forward-looking statements made by the Corporation. Any number of important factors could contribute to these digressions, including, but not limited to, general economic, political and market factors in North America and internationally, interest and foreign exchange rates, global equity and capital markets, business competition, technological change, changes in government relations, unexpected judicial or regulatory proceedings and catastrophic events. We stress that the above mentioned list of important factors is not exhaustive. We encourage you to consider these and other factors carefully before making any investment decisions and we urge you to avoid placing undue reliance on forward-looking statements. The Corporation disclaims any intention or obligation to update or revise these forward-looking statements as a result of new information, future events or otherwise, except as required under applicable securities laws.

Forward-looking statements are included throughout this Report. In particular, this Report contains forward-looking statements pertaining to the following:

- the quantity and quality of reserves or resources;
- the performance characteristics of the Company's oil and gas properties;
- oil and natural gas production levels;
- capital expenditure programs and the timing and method of financing thereof;
- future development and exploration activities and the timing thereof;
- future land expiries;
- estimated future contractual obligations and the amount expected to be incurred under our farm-in commitments;
- realization of the anticipated benefits of acquisitions and dispositions;
- future liquidity and financial capacity;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development;
- expectations relating to the award of exploration permits by governmental authorities; and
- treatment under government regulatory and taxation regimes.

With respect to forward-looking statements contained in this Report certain assumptions have been made including:

- oil and natural gas production levels;
- commodity prices;
- future currency and interest rates;
- future operating costs;
- the Company's ability to generate sufficient cash flow from operations and to access existing credit facilities and capital markets to meet its future obligations;
- availability of labour and drilling equipment;
- general economic and financial market conditions; and
- government regulation in the areas of taxation, royalty rates and environmental protection.

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:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- imprecision in estimating capital expenditures and operating expenses;
- availability of sufficient financial resources to fund the Company's capital expenditures;
- the possibility that government policies or laws, including those related to the environment, may change or governmental approvals may be delayed or withheld;
- stock market volatility and market valuation;
- potential delays or changes with respect to exploration and development projects or capital expenditures;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;

- general economic and business conditions;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- failure to realize the anticipated benefits of acquisitions; and
- the other factors identified in other documents incorporated herein by reference.

These factors should not be considered exhaustive. 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. The forward-looking statements contained in this Report are expressly qualified by this cautionary statement. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as required by securities laws.

NON-IFRS MEASURES

The Corporation's management uses and reports certain measures not prescribed by International Financial Reporting Standards (referred to as "non-IFRS measures") in the evaluation of operating and financial performance. Operating netback, which is calculated as average unit sales prices less royalties and operating expenses, and corporate netback, which further deducts administrative and interest expense, represent net cash margin calculations for every barrel of oil equivalent sold. Net debt, which is current assets less current and other financial liabilities (e.g. note payable), is used to assess efficiency and financial strength. Operating netback, corporate netback and net debt do not have any standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of a similar measure for other companies. The Corporation uses these terms as an indicator of financial performance because such terms are often utilized by investors to evaluate junior producers in the oil and natural gas sector.

OVERALL PERFORMANCE AND RESULTS OF OPERATIONS

Arctic Hunter Energy Inc. is a Canadian Oil & Gas resource exploration and development Company that is involved in the acquisition, exploration and development of oil and gas properties in Western Canada and in North America. The Company maintains a strong statement of financial position and has a qualified management team in field exploration, drilling and has the necessary manpower required to develop its natural resource and production properties.

In fiscal year 2011, the Company farmed into 3 exploratory wells which are now our Landrose C-11, C-12 and C-14 wells. These heavy oil wells are located in the Lloydminster area of Western Saskatchewan. Each well has a non-operating partner and an operating partner who maintain the daily activities. Arctic Hunter's ownership ranges between 25% and 50% of these production wells. All production from the wells is from the McLaren and Waseca formations and over the past year has averaged 28 barrels per day of net production.

In fiscal year 2012, the Company entered into a sub-participation agreement with Alberta Star Development Corp., a company with common directors, to participate in the drilling of the A-6 well in Landrose, Saskatchewan. Arctic Hunter's ownership is 25% of this production well.

On September 4, 2012, the Company announced that it had appointed Ray Lee P.L. Eng. as an addition to the Board of Directors.

Mr.Lee has thirty years of oil and gas experience, most recently as President & CEO of a private junior energy and petroleum Company. Mr. Lee has held senior positions in exploitation, production and operations engineering for natural gas and both conventional and heavy oil with a number of major and junior oil and gas companies. These companies include Tundra Oil and Gas, Compton Petroleum, Northstar Energy, Devon Energy Corp., Amoco Canada

Petroleum Company Ltd, Dome Petroleum Ltd. and Hudson's Bay Oil & Gas Company Ltd. Mr. Lee is also a Professional Licensed Engineer with APEGGA.

RESULTS OF OPERATIONS – SIX MONTH PERIOD ENDED DECEMBER 31, 2012

The Company's net comprehensive loss for the six month period ended December 31, 2012 was $57,576 or $0.00 per share compared to a net comprehensive loss of $16,383 or $0.00 per share for the six month period ended December 31, 2011. The significant changes during the six month period ended December 31, 2012 compared to the six month period ended December 31, 2011 are as follows:

Petroleum revenue during the six month period ended December 31, 2012 was $256,102, a decrease of $151,727 compared to $407,829 during the six month period ended December 31, 2011. After deducting royalties of $34,193, production and transportation costs of $58,344 and depletion and depreciation of $56,147, net petroleum production revenue of $107,418 was recorded as compared to $132,740 during the six month period ended December 31, 2011.

Consulting fees decreased $36,183 to $21,505 during the six month period ended December 31, 2012 from $57,688 during the six month period ended December 31, 2011. The costs in the prior six month period were higher due to the acquisition of the oil and gas assets.

Director fees increased $10,000 to $22,000 during the six month period ended December 31, 2012 from $12,000 during the six month period ended December 31, 2011. This was a result of a new director being appointed to the Board.

Filing fees decreased $3,196 to $10,490 during the six month period ended December 31, 2012 from $13,686 during the six month period ended December 31, 2011. The costs in the prior six month period were higher due to the acquisition of the oil and gas assets and the listing on the TSX Venture exchange.

General and administration costs increased $7,153 to $8,188 during the six month period ended December 31, 2012 from $1,035 during the six month period ended December 31, 2011 due to increased office costs.

Promotion costs increased $22,383 to $23,413 during the six month period ended December 31, 2012 from $1,030 during the six month period ended December 31, 2011 due to an investor awareness program and ongoing investor relations.

Rent increased $8,468 to $18,304 during the six month period ended December 31, 2012 from $9,836 during the six month period ended December 31, 2011 as a result of obtaining a secondary office in Calgary.

At December 31, 2012, Arctic Hunter held assets recorded at $575,770 including $282,600 in cash, $1,683 in prepaid expense, $69,577 in receivables from its oil and gas operations, $8,000 in assets held for sale and $213,910 in property, plant and equipment.

RESULTS OF OPERATIONS – THREE MONTH PERIOD ENDED DECEMBER 31, 2012

The Company's net comprehensive loss for the three month period ended December 31, 2012 was $51,943 or $0.00 per share compared to a net comprehensive loss of $2,117 or $0.00 per share for the three month period ended December 31, 2011. The significant changes during the three month period ended December 31, 2012 compared to the three month period ended December 31, 2011 are as follows:

Petroleum revenue during the three month period ended December 31, 2012 was $115,547, a decrease of $101,662 compared to $217,209 during the three month period ended December 31, 2011. After deducting royalties of

$17,067, production and transportation costs of $31,589 and depletion and depreciation of $26,790, net petroleum production revenue of $40,101 was recorded as compared to $72,163 during the three month period ended December 31, 2011.

Consulting fees decreased $16,115 to $6,505 during the three month period ended December 31, 2012 from $22,620 during the three month period ended December 31, 2011. The costs in the prior three month period were higher due to the acquisition of the oil and gas assets.

Director fees increased $6,000 to $12,000 during the three month period ended December 31, 2012 from $6,000 during the three month period ended December 31, 2011 as a new director was appointed.

General and administration costs increased $4,181 to $4,638 during the three month period ended December 31, 2012 from $457 during the three month period ended December 31, 2011 due to increased office costs.

Promotion costs increased $16,354 to $17,384 during the three month period ended December 31, 2012 from $1,030 during the three month period ended December 31, 2011 due to an investor awareness program and ongoing investor relations.

Rent increased $5,062 to $9,952 during the three month period ended December 31, 2012 from $4,890 during the three month period ended December 31, 2011 as a result of obtaining a secondary office in Calgary.

SUMMARY OF QUARTERLY RESULTS

The following selected financial information is derived from the unaudited interim financial statements of the Company. The figures have been prepared in accordance with IFRS.

	2nd Qtr Ended 12-31-12	**1st Qtr Ended 09-30-12**	**4th Qtr Ended 06-30-12**	**3rd Qtr Ended 03-31-12**	**2nd Qtr Ended 12-31-11**	**1st Qtr Ended 09-30-11**	**4th Qtr Ended 06-30-11**	**3rd Qtr Ended 03-31-11**
Total Revenues	$115,547	$140,555	$168,600	$184,797	$217,209	$190,620	$243,349	$247,882
Operating Profit (Loss)	($51,943)	($5,633)	($151,840)	($204,009)	($2,117)	($14,266)	($109,298)	($55,481)
Operating Profit (Loss) Per Share	($0.00)	($0.00)	($0.01)	($0.01)	($0.00)	($0.00)	($0.01)	($0.00)
Total Net Profit (Loss)	($51,943)	($5,633)	($151,840)	($204,009)	($2,117)	($14,266)	($109,298)	($55,481)
Total Net Profit (Loss) Per Share	($0.00)	($0.00)	($0.01)	($0.01)	($0.00)	($0.00)	($0.01)	($0.00)

FINANCIAL AND OPERATING SUMMARY
TABLE A - OPERATIONS BY QUARTER (to December 2012)

All production is conventional heavy oil

Production and per share	**Q2 2013**	**Q1 2013**	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**	**Q4 2011**	**Q3 2011**
Production - total barrels	2,063	2,330	2,885	2,803	2,919	3,182	3,469	4,379
Production - bbls/ day	**22**	**25**	**32**	**31**	**32**	**35**	**38**	**49**
Heavy oil revenue	115,547	140,555	168,600	184,797	217,209	190,620	243,349	247,882
Royalties	(17,067)	(17,126)	(48,349)	(41,275)	(58,156)	(44,478)	(55,726)	(64,096)
Production & transportation	(31,589)	(26,755)	(40,388)	(35,885)	(35,288)	(33,442)	(33,046)	(75,719)
Operating net back	66,891	96,675	79,863	107,637	123,765	112,700	154,577	108,067
General and administrative	(92,044)	(72,950)	(106,247)	(265,716)	(74,280)	(74,843)	(141,807)	(109,905)
Corporate net back	(25,153)	23,725	(26,384)	(158,079)	49,485	37,857	12,770	(1,838)
Depletion & depreciation	(26,790)	(29,357)	(125,456)	(45,930)	(51,602)	(52,123)	(122,068)	(53,643)
Other (expenses) revenue	-	-	-	-	-	-	-	-
Income (loss) for the period	**(51,943)**	**(5,633)**	**(151,840)**	**(204,009)**	**(2,117)**	**(14,266)**	**(109,298)**	**(55,481)**
Basic and diluted income (loss) per share	**(0.00)**	**(0.00)**	**(0.00)**	**(0.01)**	**(0.00)**	**(0.00)**	**(0.01)**	**0.00**
Royalties as % of petroleum revenue	**15**	**12**	**29**	**22**	**27**	**23**	**23**	**26**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	56.01	60.32	58.44	65.92	74.41	59.91	70.15	56.61
Royalties	(8.27)	(7.35)	(16.76)	(14.73)	(19.92)	(13.98)	(16.06)	(14.64)
Production and transportation	(15.31)	(11.48)	(14.00)	(12.80)	(12.09)	(10.51)	(9.53)	(17.29)
Operating net back	**32.43**	**41.49**	**27.68**	**38.39**	**42.40**	**35.42**	**44.56**	**24.68**
General and administrative	(44.62)	(31.31)	(36.83)	(94.80)	(25.45)	(23.52)	(40.88)	(25.10)
Depletion & depreciation	(12.99)	(12.60)	(43.49)	(16.39)	(17.68)	(16.38)	(35.19)	(12.25)
Income (loss) for the period	(25.18)	(2.42)	(52.64)	(72.80)	(0.73)	(4.48)	(31.51)	(12.67)
Funds (invested in) petroleum properties	**(8,218)**	**(4,930)**	**-**	**(52,944)**	**(92,482)**	**(1,711)**	**(215,752)**	**(7,078)**

FINANCIAL AND OPERATING SUMMARY
TABLE C – BALANCE SHEET

	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011
Net cash	282,600	296,644	320,267	388,592	389,521	426,652	429,097	376,387
Total assets	575,770	639,251	639,239	990,444	842,867	833,892	924,257	868,541
Total liabilities	92,027	104,218	99,269	297,768	125,160	114,068	190,167	126,811
Shareholders' equity	483,743	535,033	539,970	692,676	717,707	719,824	734,090	741,730
SHARES								
Basic outstanding	14,985,000	14,985,000	14,985,000	14,985,000	14,985,000	14,985,000	14,985,000	14,685,000
Weighted average	14,985,000	14,985,000	14,985,000	14,985,000	14,985,000	14,985,000	13,718,658	14,625,500

The above figures have been prepared in accordance with IFRS.

OPERATING RESULTS FOR THE THREE MONTH PERIOD ENDED DECEMBER 31, 2012

- **Production volumes and revenues (refer to Financial and Operating Summary)**

The C-12 oil and gas well located in the Lloydminster area of western Saskatchewan was drilled in July, 2010. The well started to produce in August, 2010 and the $377,115 cost to drill and equip was recovered by the Company in April 2011. The Company's working interest is now 50%. The average production for the well over the quarter ended December 31, 2012 was approximately 30 bbls/d (15 bbls/d net) for the Company's 50% interest.

On October 21, 2010, the Company announced it had completed and placed on production its second well in the Lloydminster area of western Saskatchewan, C-11. The Companies 50% cost of the well was $172,450 to drill and equip. The Company did not receive any production from this well during the quarter ended December 31, 2012.

The $172,450 cost associated to drill and equip the C-11 well has $91,622 remaining on its payout. After payout, the Company's future working interest will convert to 25%.

On October 27, 2010, the Company announced it had completed and placed on production its third well in the Lloydminster area of western Saskatchewan, C-14. The well started to produce in October, 2010 and the Company's 50% cost to drill and equip of $211,472 was recovered by the Company in March 2011. The Company's working interest is now 25%. The average production for the well over the quarter ended December 31, 2012 was approximately 12 bbls/d (3 bbls/d net) for the Company's 25% interest.

On January 31, 2012, the Company announced it had completed and placed on production its fourth well in the Lloydminster area of western Saskatchewan, A-6. The well started to produce in February, 2012 and the Company's 25% cost to drill and equip was $96,139. The Company's working interest is 25%. The average production for the quarter ended December 31, 2012 was approximately 20 bbls/d (5 bbls/d net) for the Company's 25% interest.

The average realized price per bbl for the fourth quarter ended December 31, 2012 was $56.01 per bbl as compared to $60.32 per bbl realized in the previous quarter. The realized average corporate prices per bbl during the quarter was lower due to increased price differentials between heavy and light crude. The December price per bbl was $41 per bbl.

- **Oil Pricing (refer to Financial and Operating Summary)**

All of the Company's crude oil consists of heavy oil produced in Saskatchewan that is marketed base on refiner's posted prices for Western Canadian Select heavy oil, adjusted for the quality (primarily density) of the crude oil on a well by well basis. The majority of the Company's heavy oil ranges in density from approximately 13.6 API to 15.9 API. The refiner's posted prices are influenced by the US$WTI reference price, transportation costs, US$/C$ exchange rates and the supply/demand situation of particular crude oil quality streams during the nine month period. The prices realized by the Company on heavy oil sales are net of treating fees, blending costs, required for its heavy grades of oil to meet pipeline stream specification, and pipeline tariffs.

The price differential between heavy and light crude oil was unfavorable again in Q2 2013 averaging $18.11 per bbl. compared to $21.72 per bbl. in Q1 2013. For October, November and December, the heavy oil differential averaged 10.8%, 16.4% and 34.4%, respectively. The weaker pricing environment for heavy oil in December (which continued into January) was driven by a combination of factors, including reduced demand due to both scheduled and unscheduled refinery maintenance, increase supply of crude oil from North Dakota Bakken and Western Canada, and increasing inventory levels at Cushing, in advance of the Seaway pipeline reversal.

The Company realized an average oil price of $56.01 per bbl in Q2 2013 as compared to $60.32 per bbl in Q1 2012.

- **Royalties (refer to Financial and Operating Summary)**

Q2 2013 overall royalty burden averaged 15% which was higher than 12% in Q1 2013. The Company incurs a mix of crown, freehold and overriding royalties. The Volumes and mix of oil wells producing in a quarter impact the overall average burden.

- **Production and transportation costs (refer to Financial and Operating Summary)**

Winter operating costs are higher than other seasons as certain costs (e.g. snowplowing) are incurred only in cold weather. A significant portion of production costs are fixed and therefore production expense per bbl varies significantly with volume. Major repairs in a quarter also significantly increase costs per bbl given the small production volumes of the Company. Heavy oil production costs tend to be higher than light oil production costs. Transportation costs are low and comprise only the trucking of clean oil short distances to the sales terminal.

- **General and administrative (refer to Financial and Operating Summary)**

As production just started as a result of the drilling of the oil and gas wells, costs per bbl will be reduced as general and administrative costs tend to be fixed.

- **Depletion and accretion (refer to Financial and Operating Summary)**

Depletion expense is a function of volume produced as it is computed on a "units of production" basis.

The 4 wells included in Property, Plant and Equipment includes $48,926 in asset retirement costs and these costs were subjected to depletion. This property included 21,600 net bbls of proven and probable reserves which is the

volume base on which depletion is computed. These numbers are preliminary and as production is stabilized, the engineering reserve report will be updated in accordance with industry standards.

Probable reserves for the property may include future locations. Under IFRS the Company chose this larger production basis for the computation of depletion. As probable reserves are determined based on a probability of recovery of 50% or more, this broader depletion base under IFRS generates a more realistic estimate of real depletion.

OUTLOOK

The Company focuses on the production of conventional heavy oil, building on the core competency of its people, further acquisitions, exploration and development in the Lloydminster area (Lloydminster is a border city 250 km east of Edmonton, Alberta and 275 km west of Saskatoon, Saskatchewan). The Company continues to implement careful control of development and monitors field production costs.

During the three month period ended December 31, 2012, production decreased slightly. Total production was averaging approximately 22 bbls per day with an average price of $56.01 per bbl as compared to 25 bbls per day with an average price of $60.32 per bbl in the previous quarter.

Future production and revenue should remain stable over the next several months.

In July of 2012 the Company submitted a formal application for an "Open Door Bid" for the Ionnina Contract area, a 4,187 sq. km block located onshore in north western Greece, with Joint Venture Partner KO Enterprises of Vancouver, BC. This is considered a highly prospective region of Greece, which is on trend with a number of large hydrocarbon discoveries and producing fields, and is considered geologically similar to other producing areas in the region. The application for exploration is currently under review and is being evaluated by the Hellenic Republic Ministry of Environment Energy and Climate Change. The Company is currently awaiting the conclusion and results of their review and is cautiously optimistic about the possibility to negotiate and sign a formal license agreement with the Ministry.

The Company continues to review a number of domestic and international opportunities and continues to be highly selective while maintaining strict and responsible growth with its domestic drilling and exploration strategies for 2013.

LIQUIDITY AND CAPITAL RESOURCES

Future development of Arctic Hunter's oil and gas property interests will depend on the Company's cash flow from its existing wells, obtain loans and its ability to obtain additional financing through the sale of its securities or to enter into acceptable agreements with third parties for joint venture development of properties. There is no assurance that such financing and joint venture development opportunities will be available when required by or under terms favourable to the Company.

At December 31, 2012, the Company had $322,290 in working capital which should be sufficient to cover expected administrative expenses for twelve months.

Otherwise, Arctic Hunter does not currently have a specific plan regarding how it will obtain future funding; however, management anticipates that additional funding will come from its current producing wells or in the form of equity financing from the sale of the Company's shares. The Company may also seek loans, although no such arrangement has been made. It may also receive proceeds from the exercise of outstanding share purchase warrants and stock options.

MANAGEMENT AND RELATED PARTY TRANSACTIONS

Arctic Hunter's Board of Directors consists of Tim Coupland, Robert Hall, Ted Burylo, David Finn and Ray Lee. Mr. Coupland acts as President and Chief Executive Officer and Mr. Gordon Steblin acts as Chief Financial Officer.

On April 1, 2006, the Company entered into a management agreement with a director of the Company. The management agreement was for an initial term of one year with a monthly remuneration of $3,500, commencing April 1, 2006 and continuing thereafter from month to month until terminated. Effective December 1, 2010, the Company increased the monthly remuneration to $6,500 per month. Management fees of $39,000 (2011 - $39,000) have been recorded for the six month period ended December 31, 2012.

Effective December 1, 2010, the Company agreed to pay $1,500 per month to the Chief Financial Officer for accounting services. Professional fees of $9,000 (2011 - $9,000) have been recorded for the six month period ended December 31, 2012.

Effective December 1, 2010, the Company agreed to pay $2,500 per month to the Vice-President of Corporate Development. Consulting fees of $15,000 (2011 - $15,000) have been recorded for the six month period ended December 31, 2012.

Effective April 1, 2012, the Company agreed to pay $2,000 per month to a Director. Director fees of $12,000 (2011 - $12,000) have been recorded for the six month period ended December 31, 2012.

Effective August 1, 2012, the Company agreed to pay $2,000 per month to a Director. Director fees of $10,000 (2011 - $Nil have been recorded for the six month period ended December 31, 2012.

The Company had no share-based payment transactions with its key management personnel for the six months ended December 31, 2012 and 2011.

Related party transactions have been recorded at their exchange amounts, which are the amounts agreed to by the related parties.

SHARE DATA

As of the date of this management discussion, Arctic Hunter has 14,985,000 common shares without par value issued and outstanding. In addition, the Company has the potential obligation to issue the following additional common shares:

a) up to 3,000,000 common shares upon the exercise of share purchase warrants at a price of $0.25 per share until October 5, 2014,

b) up to 755,000 common shares upon the exercise of incentive stock options. These options are exercisable at $0.25 per share until June 25, 2013,

c) up to 1,000,000 common shares upon the exercise of share purchase warrants at a price of $0.30 per share until May 14, 2013,

d) up to 300,000 common shares upon the exercise of share purchase warrants at a price of $0.35 per share until May 30, 2013,

e) up to 525,000 common shares upon the exercise of incentive stock options. These options are exercisable at $0.10 per share until January 9, 2015.

INVESTOR RELATIONS

The Company paid a consulting firm $6,000 to conduct investor relation awareness and social media programs during the six month period ended December 31, 2012. All in-house investor relations activity is currently being provided by Rob Hall, Vice-President of Corporate Development for the Company.

MANAGEMENT'S RESPONSABILITY FOR FINANCIAL INFORMATION

The Company's financial statements and the other financial information included in this management report are the responsibility of the Company's management, and have been examined and approved by the Board of Directors. The financial statements were prepared by management in accordance with International Financial Reporting Standards and include certain amounts based on management's best estimates using careful judgment. The selection of accounting principles and methods is management's responsibility. Management recognizes its responsibility for conducting the Company's affairs in a manner to comply with the requirements of applicable laws and established financial standards and principles, and for maintaining proper standards of conduct in its activities. The Board of Directors supervises the financial statements and other financial information through its audit committee, which is comprised of a majority of non-management directors. This committee's role is to examine the financial statements and recommend that the Board of Directors approve them, to examine the internal control and information protection systems and all other matters relating to the Company's accounting and finances. In order to do so, the audit committee meets annually with the external auditors, with or without the Company's management, to review their respective audit plans and discuss the results of their examination. This committee is responsible for recommending the appointment of the external auditors or the renewal of their engagement.

OFF BALANCE SHEET ARRANGEMENT

The Company has not engaged in any off-balance sheet arrangements such as obligations under guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity, any obligation under derivative instruments (except as disclosed) or any obligation under a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company or engages in leasing or hedging services with the Company.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development and acquisition of oil and gas reserves involves a number of business risks inherent in the oil and gas industry which may impact The Corporation's results and several of which are beyond control of the Corporation. These business risks are operational, financial or regulatory in nature. The Corporation does not use derivative instruments as a means to manage risk.

The Company has limited financial resources, no source of operating cash flows and no assurances that sufficient funding, including adequate financing, will be available to conduct further exploration and development of its projects or to fulfill its obligations under the terms of any option or joint venture agreements. If the Company's generative exploration programs are successful, additional funds will be required for development of one or more projects. Failure to obtain additional financing could result in the delay or indefinite postponement of further exploration and development or the possible loss of the Company's properties.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's financial statements requires management to make estimates and assumptions regarding future events. These estimates and assumptions affect the reported amounts of certain assets and liabilities, and disclosure of contingent liabilities.

Significant areas requiring the use of management estimates include the determination of impairment of assets, decommissioning liabilities, and variables used in determining share-based payments. These estimates are based on management's best judgment. Factors that could affect these estimates include risks inherent in mineral exploration and development, changes in reclamation requirements, changes in government policy and changes in foreign exchange rates.

Management has assessed the carrying value of its assets and does not believe the remaining assets have suffered any impairment.

The Company has certain asset retirement obligations/decommissioning liabilities related to its oil and natural gas properties, details of which are discussed in Note 3 of the financial statements for the six month period ended December 31, 2012.

Management has made significant assumptions and estimates in determining the fair market value of share-based payments granted to employees and non-employees and the value attributed to various warrants issued. These estimates have an effect on the share-based payments expense recognized and the reserve accounts and share capital balances. Management has made estimates of the life of stock options and warrants, the expected volatility and expected dividend yields that could materially affect the fair market value of these types of securities. The estimates were chosen after reviewing the historical life of the Company's options and analyzing share price history to determine volatility.

FINANCIAL INSTRUMENTS AND OTHER INSTRUMENTS

The Company classifies all financial instruments as either financial assets or liabilities through profit or loss ("FVTPL"), available-for-sale, loans and receivables or other financial liabilities. Loans and receivables and other financial liabilities are measured at amortized cost. Available-for-sale instruments are measured at fair value with unrealized gains and losses recognized in accumulated other comprehensive income. Instruments classified as FVTPL are measured at fair value with unrealized gains and losses recognized in profit or loss.

The Company has designated its cash as FVTPL, which is measured at fair value. Accounts receivables are classified as loans and receivables, which are measured at amortized cost. Accounts payable are classified as other financial liabilities which are measured at amortized cost.

Fair value - The fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying value due to the short-term nature of these financial instruments.

Exchange risk - The Company operates solely in Canada and therefore is subject to minimal foreign currency risk arising from changes in exchange rates with other currencies.

Interest rate risk - The Company is exposed to interest rate risk on its short-term investments, but this risk relates only to investments held to fund future activities and does not affect the Company's current operating activities.

Credit risk - The Company places its temporary investment funds with government and bank debt securities and is subject to minimal credit risk with regard to temporary investments.

The Company does not have any risk associated with “other instruments”; that is, instruments that may be settled by the delivery of non-financial assets.

Definitions

“Developed Non-Producing” reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

“Developed Producing” reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

“Gross Reserves” are working interest (operating or non-operating) shares before deducting royalties and without including any royalty interests.

“Net Reserves” are working interest (operating or non-operating) shares after deduction of royalty obligations, plus royalty interests in reserves.

“Probable” reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

“Proved” reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

“Undeveloped” reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mmcf	million cubic feet
Mbbls	thousand barrels	MMBtu	million British Thermal Units
MSTB	thousands of Stock Tank Barrels		

boe — barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)