MANAGEMENT DISCUSSION FOR ARCTIC HUNTER ENERGY INC.
FOR THE YEAR ENDED JUNE 30, 2012
PREPARED AS OF OCTOBER 26, 2012

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 year ended June 30, 2012, in comparison with the previous year. This report supplements our audited financial statements 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 formation and over the past year has averaged 32 barrels per day of net production.

During fiscal year 2012, the Company completed 1 new exploratory well in the Lloydminster area of Western Saskatchewan which is now producing and opted out of participating in 1 additional exploratory well in the Blackfoot area of Alberta.

On December 15, 2011, the Company changed its name from Arctic Hunter Uranium Inc. to Arctic Hunter Energy Inc. The Company’s trading symbol, AHU, remained unchanged.

On December 20, 2011, the Company entered into a sub-participation agreement with Alberta Star, a company with common directors, to participate in the drilling of one test well in Landrose, Saskatchewan, Canada. Alberta Star holds a 50% working interest in the test well. The Company agreed to pay 50% of Alberta Star’s share of the cost to drill complete, and equip or abandon the test well to earn a 25% working interest (being 50% of Alberta Star’s pre-participation 50% working interest) in the well. The Company has no option to drill post-earning wells under the sub-participation agreement. Western Plains will be the operator of the test well. Drilling completion and equipping costs for the well were $330,976 ($82,744 net to Arctic Hunter).

On February 14, 2012, the Company announced that it had placed this well into production.

On January 9, 2012, the Company announced that subject to regulatory approval, it had granted incentive stock options to certain directors, officers and consultants of the Company to purchase up to an aggregate of 525,000 common shares of the Company at a price of $0.10 per share exercisable until January 9, 2015.

On February 16, 2012, the Company extended the expiry date of 1,000,000 share purchase warrants exercisable to purchase one common share of the Company at an exercise price of $0.30 per share from the expiry date of May 14, 2012 to May 14, 2013. The warrants were issued in May 2008 in connection with a non-brokered private placement financing.

The Company also extended the expiry date of 3,000,000 share purchase warrants exercisable to purchase one common share of the Company at an exercise price of $0.25 per share from the original expiry date of October 5, 2012 to October 5, 2014. The warrants were issued in October 2009 in connection with a non-brokered private placement financing with an original term of three years.

Proceeds from any exercise of warrants will be used to continue to fund exploration activities and for working capital purposes.

On September 4, 2012, the Company announced that it had appointed Ray Lee P.L. Eng. 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.

SELECTED ANNUAL INFORMATION

Unless otherwise noted, all currency amounts are stated in Canadian dollars.

The following table summarizes selected financial data for the Company for each of the three most recently completed financial years. The 2012 and 2011 information set forth below should be read in conjunction with the consolidated audited financial statements, prepared in accordance with IFRS, and related notes. The 2010 information was prepared in accordance with Canadian GAAP.

	Years Ended June 30th, (audited)		
	2012	**2011**	**2010**
Petroleum revenue	$761,226	$1,353,731	$Nil
Operating expenses	612,372	991,338	Nil
Net petroleum revenue	148,854	362,393	Nil
General and administrative expenses	379,371	338,632	254,083
Other items	141,715	5,697	292,314
Net and comprehensive (loss) income			
o In total	(372,232)	18,064	(546,397)
o Basic and diluted (loss) income per share	(0.02)	0.00	(0.05)
Totals assets	639,239	924,257	374,035
Total long term liabilities	51,200	23,290	Nil
Cash dividends declared	Nil	Nil	Nil

RESULTS OF OPERATIONS – YEAR ENDED JUNE 30, 2012

As of June 30, 2012, the Company had incurred $377,115 to drill and equip its first heavy oil well located in the Lloydminster area of Western Saskatchewan. The well started to produce heavy oil in August, 2010 and 23 months worth of oil production has been recorded.

The Company successfully drilled its second and third heavy oil wells located in the Lloydminster area of western Saskatchewan in October, 2010. The Company's 50% cost of the wells was $383,922 to drill and equip. The wells started to produce heavy oil in October, 2010 and 21 months worth of oil production has been recorded.

The Company successfully drilled its fourth heavy oil well located in the Lloydminster area of western Saskatchewan in February, 2012. The Company's 25% cost of the well was $96,139 to drill and equip. The well started to produce heavy oil in February, 2012 and 5 months worth of oil production has been recorded.

The Company's net comprehensive loss for the year ended June 30, 2012 was $372,232 or $0.02 per share compared to a net comprehensive profit of $18,064 or $0.00 profit per share for the year ended June 30, 2011. The previous year's profit was significantly higher as the Company was accounting for 100% of the production revenue until production payout of the wells. The significant changes during the current year compared to the prior year are as follows:

Petroleum revenue during the year ended June 30, 2012 was $761,226. After deducting royalties of $192,258, production and transportation costs of $145,003 and depletion and depreciation of $275,111, net petroleum production revenue of $148,854 was recorded.

Consulting fees decreased $17,927 to $72,688 during the year ended June 30, 2012 from $90,615 during the year ended June 30, 2011. The costs in the prior year were higher due to the acquisition of the oil and gas assets.

Director fees increased $18,000 to $24,000 during the year ended June 30, 2012 from $6,000 during the year ended June 30, 2011.

Filing fees decreased $20,518 to $25,632 during the year ended June 30, 2012 from $46,150 during the year ended June 30, 2011. The costs in the prior year were higher due to the acquisition of the oil and gas assets and the listing on the TSX Venture exchange.

Exploration and evaluation costs of $40,145 were incurred to evaluate potential oil and gas properties during the year ended June 30, 2012.

Financing costs were $158,215 which includes non-cash amounts of $1,165 for the accretion of decommissioning liability and $157,050 fair value for the extension of 4,000,000 warrants during the year ended June 30, 2012.

Management fees increased $15,000 to $78,000 during the year ended June 30, 2012 from $63,000 during the year ended June 30, 2011 as a result of the renegotiated management agreement.

Professional fees decreased $46,488 to $62,457 during the year ended June 30, 2012 from $108,945 during the year ended June 30, 2011. The costs in the prior year were higher due to the acquisition of the oil and gas assets and the listing on the TSX Venture exchange.

Promotion costs were $29,151 which included $24,000 for an investor awareness program during the year ended June 30, 2012.

Rent of $20,167 remained consistent with the prior year as per the Company’s lease agreement.

Share-based payments increased $20,092 to $21,062 during the year ended June 30, 2012 from $970 during the year ended June 30, 2011 which is a non-cash item as a result of the granting and vesting of stock options.

At June 30, 2012, Arctic Hunter held assets recorded at $639,239 including $320,267 in cash, $1,683 in prepaid expense, $51,244 in receivables from its oil and gas operations, $8,000 in assets held for sale and $258,045 in property, plant and equipment.

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.

RESULTS OF OPERATIONS – YEAR ENDED JUNE 30, 2012 and 2011

	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**	**2nd Qtr Ended 12-31-10**	**1st Qtr Ended 09-30-10**
Total Revenues	$168,600	$184,797	$217,209	$190,620	$243,349	$247,882	$615,583	$246,917
Operating Profit (Loss)	($151,840)	($204,009)	($2,117)	($14,266)	($109,298)	($55,481)	$141,398	$41,445
Operating Profit (Loss) Per Share	($0.01)	($0.01)	($0.00)	($0.00)	($0.01)	($0.00)	$0.01	$0.00
Total Net Profit (Loss)	($151,840)	($204,009)	($2,117)	($14,266)	($109,298)	($55,481)	$141,398	$41,445
Total Net Profit (Loss) Per Share	($0.01)	($0.01)	($0.00)	($0.00)	($0.01)	($0.00)	$0.01	$0.00

RESULTS OF OPERATIONS – THREE MONTH PERIOD ENDED JUNE 30, 2012

The Company's net comprehensive loss for the three month period ended June 30, 2012 was $151,840 or $0.01 per share compared to a net comprehensive loss of $109,298 or $0.01 loss per share for the three month period ended June 30, 2011. The significant changes during the current three month period compared to the prior year three month period are as follows:

Petroleum revenue during the three month period ended June 30, 2012 was $168,600. After deducting royalties of $48,349, production and transportation costs of $40,388 and depletion and depreciation of $125,456, net petroleum production loss of $45,593 was recorded.

Consulting fees decreased $22,526 to $7,500 during the three month period ended June 30, 2012 from $30,026 during the three month period ended June 30, 2011. During the prior year a $19,000 cost was due to the payment of the Company's sponsorship fees with PI Financial.

Filing fees decreased $20,275 to $2,807 during the three month period ended June 30, 2012 from $23,082 during the three month period ended June 30, 2011. During the prior year a $20,000 listing application fee was paid to the TSX Venture Exchange.

Exploration and evaluation costs of $40,145 were incurred to evaluate potential oil and gas properties during the three months ended June 30, 2012.

Rent of $5,152 stayed constant as compared to the previous three month period as per the Company's lease agreement.

Management fees of $19,500 stayed constant as compared to the previous three month period ended June 30, 2011.

Director fees of $6,000 stayed constant as compared to the previous three month period ended June 30, 2011.

Promotion costs were $12,000 for an investor awareness program during the three month period ended June 30, 2012.

Professional fees decreased $26,280 to $25,080 during the three month period ended June 30, 2012 from $51,360 during the three month period ended June 30, 2011. During the prior year, $31,860 in legal fees were incurred for the listing application with the TSX Venture Exchange.

FINANCIAL AND OPERATING SUMMARY

TABLE A - OPERATIONS BY QUARTER (August 2010 to June 2012)

All production is conventional heavy oil

Production and per share	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**
Production - total barrels	2,885	2,803	2,919	3,182	3,469	4,379	10,521	4,560
Production - bbls/ day	**32**	**31**	**32**	**35**	**38**	**49**	**114**	**76**
Heavy oil revenue	168,600	184,797	217,209	190,620	243,349	247,882	615,583	246,917
Royalties	(48,349)	(41,275)	(58,156)	(44,478)	(55,726)	(64,096)	(230,908)	(64,405)
Production & transportation	(40,388)	(35,885)	(35,288)	(33,442)	(33,046)	(75,719)	(59,576)	(34,915)
Operating net back	79,863	107,637	123,765	112,700	154,577	108,067	325,099	147,597
General and administrative	(106,247)	(265,716)	(74,280)	(74,843)	(141,807)	(109,905)	(56,186)	(36,431)
Corporate net back	(26,384)	(158,079)	49,485	37,857	12,770	(1,838)	268,913	111,166
Depletion & depreciation	(125,456)	(45,930)	(51,602)	(52,123)	(122,068)	(53,643)	(127,515)	(69,721)
Other (expenses) revenue	-	-	-	-	-	-	-	-
Income (loss) for the period	**(151,840)**	**(204,009)**	**(2,117)**	**(14,266)**	**(109,298)**	**(55,481)**	**141,398**	**41,445**
Basic and diluted income (loss) per share	**(0.00)**	**(0.01)**	**(0.00)**	**(0.00)**	**(0.01)**	**0.00**	**0.01**	**0.00**
Royalties as % of petroleum revenue	**29**	**22**	**27**	**23**	**23**	**26**	**38**	**26**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	58.44	65.92	74.41	59.91	70.15	56.61	58.51	54.15
Royalties	(16.76)	(14.73)	(19.92)	(13.98)	(16.06)	(14.64)	(21.95)	(14.12)
Production and transportation	(14.00)	(12.80)	(12.09)	(10.51)	(9.53)	(17.29)	(5.66)	(7.66)
Operating net back	**27.68**	**38.39**	**42.40**	**35.42**	**44.56**	**24.68**	**30.90**	**32.37**
General and administrative	(36.83)	(94.80)	(25.45)	(23.52)	(40.88)	(25.10)	(5.34)	(7.99)
Depletion & depreciation	(43.49)	(16.39)	(17.68)	(16.38)	(35.19)	(12.25)	(12.12)	(21.84)
Other revenue	-	-	-	-	-	-	-	-
Income (loss) for the period	(52.64)	(72.80)	(0.73)	(4.48)	(31.51)	(12.67)	13.44	2.54
Funds (invested in) petroleum properties	**-**	**(52,944)**	**(92,482)**	**(1,711)**	**(215,752)**	**(7,078)**	**(243,605)**	**(243,605)**

FINANCIAL AND OPERATING SUMMARY
TABLE C – BALANCE SHEET

	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Net cash	320,267	388,592	389,521	426,652	429,097	376,387	421,408	159,824
Total assets	639,239	990,444	842,867	833,892	924,257	868,541	932,977	407,059
Total liabilities	99,269	297,768	125,160	114,068	190,167	126,811	250,766	134,503
Shareholders' equity	539,970	692,676	717,707	719,824	734,090	741,730	682,211	272,557
SHARES								
Basic outstanding	14,985,000	14,985,000	14,985,000	14,985,000	14,985,000	14,685,000	13,920,000	12,700,000
Weighted average	14,985,000	14,985,000	14,985,000	14,985,000	13,718,658	14,625,500	12,746,413	12,700,000

The above figures have been prepared in accordance with IFRS.

OPERATING RESULTS FOR THE YEAR ENDED JUNE 30, 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 June 30, 2012 was approximately 37 bbls/d (18 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 June 30, 2012.

The $172,450 cost associated to drill and equip the C-11 well has $87,003 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 June 30, 2012 was approximately 27 bbls/d (7 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 well from February to June, 2012 was approximately 19 bbls/d (5 bbls/d net) for the Company's 25% interest.

The average realized price per bbl for the fourth quarter ended June 30, 2012 was $58.44 per bbl as compared to $65.92 per bbl in the previous quarter. The realized average corporate prices per bbl during the quarter was lower due to decreased demand resulting in lower realized crude oil pricing. The current price per bbl is relatively the same.

- **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 Q4 2012 averaging $24.03 per bbl. compared to $20.67 per bbl. in Q3 2012. For April, May and June, the heavy oil differential averaged 31.9%, 20.7% and 19.5%, respectively. The weaker pricing environment for heavy oil in June (which continued into July) 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 $58.44 per bbl in Q4 2012 as compared to $65.92 per bbl in Q3 2012.

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

Q4 2012 overall royalty burden averaged 29% which was slightly higher than 22% in Q3 2012. 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 field production costs.

During the three month period ended June 30, 2012, production increased slightly due to initial production from two new wells being brought onto production. Total production was averaging approximately 32 bbls per day with an average price of $58.44 per bbl as compared to 31 bbls per day with an average price of $65.92 per bbl in the previous quarter.

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

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 June 30, 2012, the Company had $333,125 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 $78,000 (2011 - $63,000) have been recorded for the year ended June 30, 2012. During the year, 100,000 options to purchase shares at $0.10 per share were granted with an estimated fair value of $4,603.

Effective December 1, 2010, the Company agreed to pay $1,500 per month to the Chief Financial Officer for accounting services. Professional fees of $18,000 (2011 - $10,500) have been recorded for the year ended June 30, 2012. During the year ended June 30, 2012, 100,000 options to purchase shares at $0.10 per share were granted with an estimated fair value of $4,603.

Effective December 1, 2010, the Company agreed to pay $2,500 per month to the Vice-President of Corporate Development. Consulting fees of $30,000 (2011 - $17,500) have been recorded for the year ended June 30, 2012. During the year ended June 30, 2012, 75,000 options to purchase shares at $0.10 per share were granted with an estimated fair value of $3,452.

Effective April 1, 2012, the Company agreed to pay $2,000 per month to a Director. Director fees of $24,000 (2011 - $6,000) have been recorded for the year ended June 30, 2012. During the year ended June 30, 2012, 75,000 options to purchase shares at $0.10 per share were granted with an estimated fair value of $3,452.

During the year ended June 30, 2012, 75,000 options to purchase shares at $0.10 per share were granted to a director with an estimated fair value of $3,452.

During the year ended June 30, 2012, the Company paid consulting fees of $Nil (2011 - $10,000) to a former director.

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 500,000 common shares upon the exercise of share purchase warrants at a price of $0.35 per share until December 23, 2012,

e) up to 150,000 common shares upon the exercise of incentive stock options. These options are exercisable at $0.20 per share until January 7, 2013,

f) 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,

g) 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 $24,000 to conduct investor relation awareness and social media programs during the year ended June 30, 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 generally accepted Canadian accounting principles 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.

The external auditors, James Stafford, Inc. Chartered Accountants, have audited the Company's June 30, 2012 annual financial statements with their report indicating the scope of their audit and their opinion on the financial statements.

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 year ended June 30, 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.

CHANGES IN ACCOUNTING POLICIES – INITIAL ADOPTION

International financial reporting standards ("IFRS")

The Company's audited financial statements as at and for the years ended June 30, 2012 and 2011 have been prepared in accordance with IFRS as issued by the IASB. Previously, the Company prepared its 2011 annual financial statements in accordance with Canadian GAAP.

IFRS 1 requires the consistent and retrospective application of IFRS accounting policies as at and for the year ended June 30, 2011 and an opening Statement of Financial Position as at July 1, 2010. To assist with the transition, the provisions of IFRS 1 allows for certain mandatory and optional exemptions for first-time adopters to alleviate the full retrospective application of IFRS. The Company has elected to apply the following relevant exemptions:

Share-based Payments – IFRS 1 encourages, but does not require, first time adopters to apply IFRS 2, Share-based Payment to equity instruments that were granted on or before November 7, 2002, or equity instruments that were granted subsequent to November 7, 2002 and vested before July 1, 2010. The Company elected not to apply IFRS 2 to equity instruments that vested prior to July 1, 2010.

Full Cost Accounting for Oil and Gas Companies – IFRS 1 provides an exemption for entities that have used the full cost method of accounting under Canadian GAAP. The Company elected to measure its oil and gas assets at July 1, 2010 at amounts determined under Canadian GAAP. The Company did not have exploration and evaluation assets as at July 1, 2010.

Decommissioning Provision – IFRS 1 requires entities that have taken advantage of the full cost accounting election to measure their decommissioning liabilities on transition under IAS 37 and to treat any difference between this amount and the amount recognized under Canadian GAAP as an adjustment to deficit.

Hindsight was not used to create or revise estimates and accordingly the estimates previously made by the Company under Canadian GAAP are consistent with their application under IFRS. A summary of IFRS 1 mandatory and optional exemptions are described in Note 12 to the annual financial statements.

The IFRS accounting policies are set forth in Note 2 to the annual audited financial statements. A detailed explanation of how the transition from Canadian GAAP to IFRS has affected the Company's financial position, financial performance and cash flow, including the reconciliations required by IFRS 1, is presented in Note 12 to the financial statements.

Canadian GAAP to IFRS differences:

(a) Flow-through Shares

Flow-through shares are a unique Canadian tax incentive which is the subject of specific guidance under Canadian GAAP. Under Canadian GAAP, the Company accounted for the issue of flow-through shares in accordance with the provisions of CICA Emerging Issues Committee Abstract 146, "Flow-through Shares". At the time of issue, the funds received are recorded as share capital. At the time of the filing of the renunciation of the qualifying flow-through expenditures to investors, the Company recorded a deferred tax liability with a charge directly to shareholders' equity. Also under Canadian GAAP, a portion of the deferred tax assets that were not recognized in previous years, due to the recording of a valuation allowance, are recognized as a recovery of income taxes.

IFRS does not contain explicit guidance pertaining to this tax incentive. Therefore, the Company has adopted a policy whereby the premium paid for flow-through shares in excess of the market value of the shares without the flow-through features at the time of issue is initially recorded as a flow-through liability. Upon renouncement by the Company of the tax benefits associated with the related expenditures, a deferred tax liability is recognized and the flow-through liability is reversed, with any difference recorded as deferred tax expense. A portion of the deferred tax assets that were not recognized in previous years, due to the recording of a valuation allowance, will reduce the deferred tax liability and record a deferred tax recovery.

The change in accounting policy related to flow-through shares resulted in an increase in share capital and an increase in deficit of $12,500 as at the Transition Date and a further increase in share capital and a decrease in flow-through share income of $12,540 for the year ended June 30, 2011.

In addition, during the year ended June 30, 2010, the Company accrued an indemnification loss of $37,500 for the loss of tax credits to the flow-through investors as a reduction in share capital. During the year ended June 30, 2011, the Company recorded an adjustment to the indemnification loss by increasing the share capital by $16,400. On transition to IFRS, the Company reclassified its indemnification loss to flow-through share income or expense.

(b) Depletion and Depreciation

Under Canadian GAAP, the full cost pool was depleted as one unit on a unit-of-production basis over proven reserves. Under IFRS, the Company depletes petroleum and natural gas interests on a unit of production basis over proven plus probable reserves. In addition, depletion is calculated at an individual component level.

The change in accounting policy related to depletion and depreciation resulted in an increase in petroleum and natural gas properties with a corresponding decrease in depletion and depreciation of $53,717 for the year ended June 30, 2011.

(c) Reclassification within Equity

Under Canadian GAAP, "Contributed surplus" was used to record the issuance of warrants and stock options for the year ended June 30, 2011. Upon adoption of IFRS, the balances in "Contributed surplus" have been reclassified to "Stock option reserve" and "Warrants reserve".

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)