MANAGEMENT DISCUSSION FOR ARCTIC HUNTER ENERGY INC.
FOR THE NINE MONTH PERIOD ENDED MARCH 31, 2012
PREPARED AS OF MAY 29, 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 nine month period ended March 31, 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 resource exploration and development company that is involved in the acquisition, exploration and development of oil and gas properties in Western Canada. The Company is a Vancouver based, junior heavy oil producer. The Company is currently producing heavy oil on its Landrose, Saskatchewan heavy oil property and in east central Alberta. The Company plans on maximizing its future production through property acquisitions and exploration drilling activities. The Company also intends to devote a portion of its corporate efforts to reviewing the assessment and acquisition of additional oil and gas exploration properties.

The Company maintains a strong balance sheet and has a qualified management team in field exploration, drilling and has the necessary manpower to development its natural resource and production properties. The Company is committed to creating long term shareholder value through the acquisition, exploration and development of petroleum and natural gas resources.

On July 5, 2010, the Company entered into a farm-out agreement with Western Plains Petroleum Ltd. ("Western Plains")**.** 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 $361,628 cost to drill and equip was recovered by the Company in April 2011. The Company's working interest is now 50%. The average production over the quarter ended March 31, 2012 was approximately 20 bbls/d for the Company's 50% interest.

On October 15, 2010, the Company announced it had entered into a sub-participation agreement with Alberta Star Development Corp. ("Alberta Star"). Under the agreement, Arctic Hunter agreed to participate with Alberta Star in the two (2) test wells by October 31, 2010. Alberta Star holds a 50% working interest in the Landrose, Saskatchewan assets which form part of the heavy oil assets acquired by Alberta Star on August 6, 2010 from Western Plains. Under the agreement, Arctic Hunter paid 100% of Alberta Star's share of the cost to drill, complete and equip or abandon the test wells to earn a (50% net) interest before payout (BPO), reserving to Alberta Star a convertible overriding royalty of 10% until payout. After payout, Alberta Star has the option to either convert the gross overriding royalty to a 50% working interest (25% net) in the two test well spacing units or remain in a gross overriding royalty position. Arctic Hunter has no option to drill post-earning wells under the sub-participation agreement. Western Plains is the operator of the test wells.

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 received some revenue from this well but has not received any production for the quarter ended March 31, 2012.

The $172,450 cost associated to drill and equip the C-11 well has $67,506 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 $177,672 was recovered by the Company in March 2011. The Company's working interest is now 25%. The average production over the quarter ended March 31, 2012 was approximately 6 bbls/d for the Company's 25% interest.

Combined production flow from the C-12 and C-14 wells over the quarter ended March 31, 2012 was approximately 26 bbls/d net of heavy oil. All production from the wells is from the McLaren formation.

On December 6, 2011, the Company announced it had entered into a farm-out agreement with Sahara Energy Ltd., Forent Energy Ltd. (as Farmors) and Petrocapita Oil and Gas L.P. (as Farmee together with the Company).

Under the terms of agreement, the Company and Petrocapita have agreed to spud one test well by December 13, 2011 on LSD 4, Section 2-50-2W4M in the Lloydminster area of eastern Alberta. Arctic Hunter and Petrocapita will pay 100% of the costs (50% to Arctic Hunter and 50% to Petrocapita) to drill, complete and equip or abandon the test well to earn a 100% working interest (50% to Arctic Hunter and 50% to Petrocapita) subject to an overriding royalty in favour of Forent equal to 6% of gross monthly production from the well until payments of $43,781.85 have been made pursuant to the royalty, afterwhich the royalty will be reduced to 5% and split equally between Forent and Sahara (as to 2.5% each). Petrocapita will be the operator of the test well. Arctic Hunter has no option to drill post-earning wells under the farm-out agreement.

On February 6, 2012, the Company announced that it had participated in successfully drilling, completing and bringing this well into production. Arctic Hunter's share of drilling completion and equipping costs in connection with the well were $179,332. Arctic Hunter has no option to drill post-earning wells under the farm-out agreement.

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 and since being placed on production in February 2012, the well has produced at an average rate of 36 bbls/d of heavy oil. (9 net bbls/d to the Company).

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.

SUMMARY OF QUARTERLY RESULTS

The following selected financial information is derived from the unaudited interim financial statements of the Company. The figures for the quarters ended September 30, 2010, December 31, 2010, March 31, 2011, September 30, 2011, December 31, 2011 and March 31, 2012 have been prepared in accordance with IFRS, and the remaining figures have been prepared in accordance with Canadian GAAP.

	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**	**4th Qtr Ended 06-30-10**
Total Revenues	$207,124	$217,209	$190,620	$243,348	$247,882	$615,584	$246,917	$Nil
Operating Profit (Loss)	($201,644)	($2,117)	($14,266)	($176,746)	($55,481)	$167,084	$41,445	($61,482)
Operating Profit (Loss) Per Share	($0.01)	($0.00)	($0.00)	($0.01)	$0.00	$0.01	$0.00	($0.01)
Total Net Profit (Loss)	($201,644)	($2,117)	($14,266)	($137,006)	($55,481)	$167,084	$41,445	($447,171)
Total Net Profit (Loss) Per Share	$0.01	$0.00	($0.00)	($0.01)	$0.00	$0.01	$0.00	($0.04)

RESULTS OF OPERATIONS – NINE MONTH PERIOD ENDED MARCH 31, 2012

The Company successfully drilled its first heavy oil well located in the Lloydminster area of western Saskatchewan in July, 2010. The well cost was $361,628 to drill and equip and after adding $11,351 in asset retirement costs, the total cost was $372,979. 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 $350,122 to drill and equip and after adding $10,830 in asset retirement costs, the total cost was $360,952. 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 $82,744 to drill and equip. The well started to produce heavy oil in February, 2012 and 2 months worth of oil production has been recorded.

The Company successfully drilled its fifth heavy oil well located in the Lloydminster area of eastern Alberta in February, 2012. The Company's 50% cost of the well was $179,332 to drill and equip. The well started to produce heavy oil in March, 2012 and 1 month worth of oil production has been recorded.

The Company's net comprehensive loss for the nine month period ended March 31, 2012 was $218,027 or $0.01 per share compared to a net comprehensive profit of $157,609 or $0.01 profit per share for the nine month period ended March 31, 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 nine month period compared to the prior year nine month period are as follows:

Petroleum revenue during the nine month period ended March 31, 2012 was $614,953. After deducting royalties of $149,239, production and transportation costs of $113,919 and depletion and amortization of $154,983, net petroleum production revenue of $196,812 was recorded.

Consulting fees increased $4,599 to $65,188 during the nine month period ended March 31, 2012 from $60,589 during the nine month period ended March 31, 2011 due to increase activity of the Company.

Rent of $15,014 stayed constant as compared to the previous nine month period as per the Company's lease agreement.

Management fees increased $15,000 to $58,500 during the nine month period ended March 31, 2012 from $43,500 during the nine month period ended March 31, 2011 as a result of the renegotiated management agreement.

Professional fees decreased $20,208 to $37,377 during the nine month period ended March 31, 2012 from $57,585 during the nine month period ended March 31, 2011.

Financing costs were $157,923 which includes non-cash amounts of $873 for the accretion of decommissioning liability and $157,050 fair value for the extension of 4,000,000 warrants during the nine month period ended March 31, 2012.

Director fees increased $18,000 to $18,000 during the nine month period ended March 31, 2012 from $Nil during the nine month period ended March 31, 2011.

Promotion costs were $17,151 which included $12,000 for an investor awareness program during the nine month period ended March 31, 2012.

At March 31, 2012, Arctic Hunter held assets recorded at $990,444 including $388,592 in cash, $1,683 in prepaid expense, $95,983 in receivables from its oil and gas operations and $504,186 in property, plant and equipment.

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

The Company's net comprehensive loss for the three month period ended March 31, 2012 was $201,644 or $0.01 per share compared to a net comprehensive loss of $34,520 or $0.00 loss per share for the three month period ended March 31, 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 March 31, 2012 was $207,124. After deducting royalties of $46,605, production and transportation costs of $45,189 and depletion and amortization of $51,258, net petroleum production revenue of $64,072 was recorded.

Consulting fees decreased $26,000 to $7,500 during the three month period ended March 31, 2012 from $33,500 during the three month period ended March 31, 2011.

Rent of $5,178 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.

Professional fees decreased $15,026 to $23,111 during the three month period ended March 31, 2012 from $38,137 during the three month period ended March 31, 2011.

Financing costs were $157,341 which includes non-cash amounts of $291 for the accretion of decommissioning liability and $157,050 fair value for the extension of 4,000,000 warrants during the three month period ended March 31, 2012.

Director fees increased $6,000 to $6,000 during the three month period ended March 31, 2012 from $Nil during the three month period ended March 31, 2011.

Promotion costs were $16,121 which included $12,000 for an investor awareness program during the three month period ended March 31, 2012.

FINANCIAL AND OPERATING SUMMARY
TABLE A - OPERATIONS BY QUARTER (August 2010 to March 2012)

All production is conventional heavy oil

Production and per share	**Q3 2012**	**Q2 2012**	**Q1 2012**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**
Production - total barrels	3,173	2,919	3,182	3,469	4,379	10,521	4,560
Production - bbls/ day	**35**	**32**	**35**	**38**	**49**	**114**	**76**
Heavy oil revenue	207,124	217,209	190,620	243,348	247,882	615,584	246,917
Royalties	(46,605)	(58,156)	(44,478)	(55,726)	(64,096)	(230,908)	(64,405)
Production & transportation	(45,189)	(35,288)	(33,442)	(33,046)	(75,719)	(59,576)	(34,915)
Operating net back	115,330	123,765	112,700	154,576	108,067	325,100	147,597
General and administrative	(265,716)	(74,280)	(74,843)	(185,406)	(109,905)	(56,187)	(36,431)
Corporate net back	(150,386)	49,485	37,857	(30,830)	(1,838)	268,913	111,166
Depletion & depreciation	(51,258)	(51,602)	(52,123)	(145,916)	(53,643)	(127,515)	(69,721)
Other (expenses) revenue	-	-	-	39,740	-	-	-
Income (loss) for the period	**(201,644)**	**(2,117)**	**(14,266)**	**(137,006)**	**(55,481)**	**141,398**	**41,445**
Basic and diluted income (loss) per share	**(0.01)**	**(0.00)**	**(0.00)**	**(0.01)**	**0.00**	**0.01**	**0.00**
Royalties as % of petroleum revenue	**23**	**27**	**23**	**23**	**26**	**38**	**26**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	65.28	74.41	59.91	70.15	56.61	58.51	54.15
Royalties	(14.69)	(19.92)	(13.98)	(16.06)	(14.64)	(21.95)	(14.12)
Production and transportation	(14.24)	(12.09)	(10.51)	(9.53)	(17.29)	(5.66)	(7.66)
Operating net back	**36.35**	**42.40**	**35.42**	**44.56**	**24.68**	**30.90**	**32.37**
General and administrative	(83.74)	(25.45)	(23.52)	(53.45)	25.10)	(5.34)	(7.99)
Depletion & depreciation	(16.15)	(17.68)	(16.38)	(42.06)	(12.25)	(12.12)	(21.84)
Other revenue	-	-	-	11.46	-	-	-
Income (loss) for the period	(63.54)	(0.73)	(4.48)	(39.49)	(12.67)	13.44	2.54
Funds (invested in) petroleum properties	**(128,258)**	**(92,482)**	**(1,711)**	**(215,752)**	**(7,078)**	**(243,605)**	**(243,605)**

FINANCIAL AND OPERATING SUMMARY
TABLE C – BALANCE SHEET

	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Net cash	388,592	389,521	426,652	429,097	376,387	421,408	159,824
Total assets	990,444	842,867	833,892	924,257	868,541	932,977	407,059
Total liabilities	297,768	125,160	114,068	190,167	126,811	250,766	134,503
Shareholders' equity	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	14,685,000	13,920,000	12,700,000
Weighted average	14,985,000	14,985,000	14,985,000	13,718,658	14,625,500	12,746,413	12,700,000

The above figures for the quarters ended March 31, 2012, December 31, 2011, September 30, 2011, June 30, 2011, March 31, 2010, December 31, 2010 and September 30, 2010 have been prepared in accordance with IFRS.

OPERATING RESULTS FOR NINE MONTHS ENDED MARCH 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 $361,628 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 March 31, 2012 was approximately 40 bbls/d (20 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 March 31, 2012.

The $172,450 cost associated to drill and equip the C-11 well has $67,506 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 $177,672 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 March 31, 2012 was approximately 24 bbls/d (6 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 $82,744. The Company's working interest is 25%. The average production for the well over February and March, 2012 was approximately 36 bbls/d (9 bbls/d net) for the Company's 25% interest.

On February 6, 2012, the Company announced it had completed and placed on production its fifth well in the Blackfoot area of east central Alberta, KITS-04. The well started to produce in March, 2012 and the Company's 50% cost to drill and equip of $179,332. The Company's working interest is 50%. The average initial production for the well over March, 2012 was approximately 24 bbls/d (12 bbls/d net) for the Company's 50% interest.

The average realized price per bbl for the third quarter ended March 31, 2012 was $65.28 per bbl as compared to $74.41 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 Q3 2012 averaging $21.42 per bbl. compared to $10.48 per bbl. in Q2 2012. For January, February, and March, the heavy oil differential averaged 13.8%, 18.8% and 29.4%, respectively. The weaker pricing environment for heavy oil in March (which continued into April) 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 $65.28 per bbl in Q3 2012 as compared to $74.41 per bbl in Q2 2012.

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

Q3 2012 overall royalty burden averaged 23% which was slightly lower than 27% in Q2 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.

The "Financial and Operating Summaries" show royalty expense as 23 per cent of oil sales for the third quarter ended March 31, 2012.

- **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. The plans to drill additional wells to increase production should reduce production costs per bbl for 2012 and beyond.

- **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 C-12 well drilled in Q1 2010 added $372,979 to Property, Plant and Equipment which includes $11,351 in asset retirement costs and these costs were subjected to depletion. This property included 11,000 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.

The C-11 well drilled in Q1 2010 added $177,604 to Property, Plant and Equipment which includes $5,154 in asset retirement obligations and these costs were subjected to depletion. This property included 5,000 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.

The C-14 well drilled in Q1 2010 added $183,348 to Property, Plant and Equipment which includes $5,676 in asset retirement obligations and these costs were subjected to depletion. This property included 5,000 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 is implementing careful control of development and field production costs.

During the three month period ended March 31, 2012, production increased slightly due to initial production from two new wells being brought onto production. Total production was averaging approximately 35 bbls per day with an average price of $65.28 per bbl as compared to 32 bbls per day with an average price of $74.41 per bbl in the previous quarter.

Current production is expected to increase with the restoration of lost production due to a work over on the C-11 well. The $172,450 cost associated to drill and equip the C-11 well has $67,506 remaining on its payout. After payout, the Company’s future working interest will convert to 25%.

On December 6, 2011, the Company announced it had entered into a farm-out agreement with Sahara Energy Ltd., Forent Energy Ltd. (as Farmors) and Petrocapita Oil and Gas L.P. (as Farmee together with the Company).

Under the terms of agreement, the Company and Petrocapita have agreed to spud one test well by December 13, 2011 on LSD 4, Section 2-50-2W4M in the Lloydminster area of eastern Alberta. Arctic Hunter and Petrocapita will pay 100% of the costs (50% to Arctic Hunter and 50% to Petrocapita) to drill, complete and equip or abandon the test well to earn a 100% working interest (50% to Arctic Hunter and 50% to Petrocapita) subject to an overriding royalty in favour of Forent equal to 6% of gross monthly production from the well until payments of $43,781.85 have been made pursuant to the royalty, afterwhich the royalty will be reduced to 5% and split equally between Forent and Sahara (as to 2.5% each). Petrocapita will be the operator of the test well. Arctic Hunter has no option to drill post-earning wells under the farm-out agreement.

On February 6, 2012, the Company announced that it had participated in successfully drilling, completing and bringing this well into production.

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.

On February 14, 2012, the Company announced that it had placed this well into production and since being placed on production in February 2012, the well has produced at an average rate of 36 bbls/d of heavy oil. (9 net bbls/d to the Company).

LIQUIDITY AND CAPITAL RESOURCES

Arctic Hunter Energy Inc. is a Canadian resource exploration and development company that is involved in the acquisition, exploration and development of oil and gas properties in Western Canada. The Company is a Vancouver based, junior heavy oil producer. Combined production flow from the C-12, C-14, A-6 and KITS-04 wells over the quarter ended March 31, 2012 was approximately 35 bbls/d gross of heavy oil on its heavy oil properties.

The Company has a growing production base, and is maximizing future production through its property acquisitions and its exploration drilling activities. The Company also intends to devote a portion of its corporate efforts to reviewing the assessment and acquisition of additional oil and gas exploration properties.

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 March 31, 2012, the Company had $388,592 and 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 and David Finn. Mr. Coupland acts as President and Chief Executive Officer, Mr. Steblin acts as Chief Financial Officer and Mr. Hall acts as Vice-President of Corporate Development.

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 $58,500 (2011 - $43,500) have been recorded for the nine month period ended March 31, 2012. During the period, 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 $13,500 (2011 - $6,000) have been recorded for the nine month period ended March 31, 2012. During the period, 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 $22,500 (2011 - $10,000) have been recorded for the nine month period ended March 31, 2012. During the period, 75,000 options to purchase shares at $0.10 per share were granted with an estimated fair value of $3,452.

Effective April 1, 2011, the Company agreed to pay $2,000 per month to a Director. Director fees of $18,000 (2011 - $Nil) have been recorded for the nine month period ended March 31, 2012. During the period, 75,000 options to purchase shares at $0.10 per share were granted with an estimated fair value of $3,452.

During the period, 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 nine month period ended March 31, 2012, the Company paid consulting fees of $Nil (2011 - $10,000) to a former director.

At March 31, 2012, the Company had a receivable of $28,947 (June 30, 2011: $33,669) from a company with common directors for the net revenue in three producing wells in Landrose, Saskatchewan.

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 May14, 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 $12,000 to conduct investor relation awareness and social media programs during the 3 month period ended March 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 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, Dale Matheson Carr-Hilton LaBonte LLP appointed by the shareholders at the Annual General Meeting have audited the Company's June 30 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 three and nine months ended March 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.

CHANGES IN ACCOUNTING POLICIES – INITIAL ADOPTION

International financial reporting standards ("IFRS")

The Canadian Accounting Standards Board declared that International Financial Reporting Standards is to replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on or after January 1, 2011.

In order to produce the required financial statements in accordance with IAS 34, the Company used accounting policies consistent with IFRS as issued by the IASB and interpretations of IFRIC.

The condensed interim financial statements for the three and nine month periods ended March 31, 2012 are the Company's third condensed interim financial statements prepared in accordance with IAS 34 using accounting policies consistent with IFRS. These condensed interim financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company's first condensed interim financial statements prepared in accordance with IAS 34 and IFRS dated September 30, 2011.

The adoption of IFRS resulted in changes to the accounting policies as compared with the most recent annual financial statements prepared under Canadian GAAP. The accounting policies set out in the Company's financial statements have been applied consistently to all periods presented.

Transition to IFRS

The Company has adopted IFRS with a transition date of July 1, 2011 (the "Transition Date"). Under IFRS 1, First-time Adoption of International Financial Reporting Standards, the Company elected to take the following IFRS 1 optional exemption:

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.

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.

IFRS employs a conceptual framework that is similar to Canadian GAAP. However, significant differences exist in certain matters of recognition, measurement and disclosure. While adoption of IFRS has not changed the Company's actual cash flows, it has resulted in changes to the Company's reported financial position and results of operations. In order to allow users to better understand these changes, the Company has provided the reconciliations between Canadian GAAP and IFRS in Note 10 to the condensed interim 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 deferred tax recovery 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 deferred tax 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, of which $9,286 was adjusted for the three months ended March 31, 2011 and $39,155 for the nine months ended March 31, 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".

Detailed schedules of the impact of these changes are included in Note 10 of the condensed interim financial statements for the nine months ended March 31, 2012.

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)