MANAGEMENT DISCUSSION FOR ARCTIC HUNTER URANIUM INC.
FOR THE YEAR ENDED JUNE 30, 2011
PREPARED AS OF OCTOBER 17, 2011

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, 2011, 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 generally accepted standards in Canada 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-GAAP MEASURES

The Corporation’s management uses and reports certain measures not prescribed by generally accepted accounting principles (referred to as “non-GAAP 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 GAAP 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 Uranium 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 an Alberta based, junior heavy oil producer. The Company is currently producing heavy oil on its Landrose, Saskatchewan heavy oil property. 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.

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 to increase its oil production and reserves through its exploration activities and strategic property acquisitions.

On July 5, 2010, the Company entered into a farm-out agreement with Western Plains Petroleum Ltd. (“Western Plains”)**.** Under the agreement, the Company agreed to spud one test well by July 31, 2010 on section 6-50-25 W3M in the Lloydminster area of western Saskatchewan. The Company paid 100% of the costs to drill, complete and equip or abandon the test well to earn a 100% working interest before payout subject to a 10% convertible overriding royalty and a 50% working interest after payout, upon conversion of the overriding royalty. The Company has no option to drill post-earning wells under the farm-out agreement. Western Plains will be the operator of the test well. The Company intends to use the proceeds from its non-brokered flow-through private placement to fund drilling the test well on the Lloydminster property, to incur Canadian Exploration Expenses for the purposes of the *Income Tax Act* (Canada).

On July 19, 2010, the well situated at (C-12) 6-50-25 W3M was successfully drilled and started producing at an initial gross rate of approximately 80 bbls/d. The Company controlled the well production in accordance with established good oil field practices and the average production over the quarter ended June 30, 2011 was approximately 52 bbls/d (26 bbls/d net after payout to the Company).

In April 2011, the $360,854 cost associated to drill and equip the C-12 well was recovered by the Company and in accordance with the agreement, the Company's working interest is now 50%.

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 previously announced well located at C11-6-50-25 W3M ("C-11"). The Company controlled the well production in accordance with established good oil field practices and the average production over the quarter ended June 30, 2011 was approximately 7 bbls/d (2 bbls/d net after payout to the Company). The Company is currently recording 4 bbls/d until payout is obtained.

The $171,784 cost associated to drill and equip the C-11 well has $59,276 remaining on its payout as at June 30, 2011. After payout, the Company's future working interest will convert to 25%.

On October 27, 2010, the Company announced that it had completed and placed on production its previously announced third well located at C14-6-50-25 W3M ("C-14"). The initial production rate from the C-14 well, was approximately 80 bbls/d (20 bbls/d net after payout to the Company). The C-14 well is offsetting the Company's producing C11-6-50-W3M ("C-11") and the C12-6-50-25 W3M ("C-12") wells. The Company controlled the well production in accordance with established good oil field practices and the average production over the quarter ended June 30, 2011 was approximately 32 bbls/d (8 bbls/d net after payout to the Company).

In March 2011, the $177,402 cost associated to drill and equip the C-14 well was recovered by the Company and in accordance with the agreement, the Company's working interest is now 25%.

Combined production flow from the C-11, C-12 and C-14 wells over the quarter ended June 30, 2011 was approximately 38 bbls/d net of heavy oil. All production from the wells is from the McLaren formation.

On December 31, 2010, the Company announced that it had completed the first tranche of its previously announced non-brokered private placement. The Company issued a total of 560,000 flow-through units ("FT Units") of the Company at a subscription price of $0.25 per unit and 660,000 non-flow-through units ("NFT Units") of the Company at a subscription price of $0.20 per unit, for total gross proceeds of $272,000. Each FT Unit consists of one flow-through common share of the Company and one-half of one share purchase warrant ("FT Warrant"). Each flow-through share qualifies as a "flow-through share" for the purposes of the *Income Tax Act* (Canada). Each NFT Unit consists of one common share of the Company and one-half of one share purchase warrant ("NFT Warrant"). Each whole FT Warrant is exercisable into a common share of the Issuer at a price of $0.35 per share for a period of 12 months from the closing date. Each whole NFT Warrant is exercisable into a common share of the Issuer at a price of $0.25 per share for a period of 12 months from the closing date.

The proceeds from the offering will be used to fund exploration on the Company's resource properties, which will constitute Canadian exploration expenditures (as defined in the *Income Tax Act* (Canada)) and will be renounced for the 2010 tax year.

On January 10, 2011, the Company announced that it had completed the final tranche of its previously announced non-brokered private placement. The Company issued a total of 765,000 non-flow-through units ("NFT Units") of the Company at a subscription price of $0.20 per unit, for total gross proceeds of $153,000. Each NFT Unit consists of one common share of the Company and one-half of one share purchase warrant ("NFT Warrants"). Each whole NFT Warrant is exercisable into a common share of the Issuer at a price of $0.25 per share for a period of 12 months from the closing date.

In the aggregate, when combined with the units issued in prior closings undertaken in connection with the private placement, the Company issued an aggregate of 560,000 flow-through units ("FT Units") at a price of $0.25 per unit and 1,425,000 NFT Units at a price of $0.20 per unit, for total gross proceeds of $425,000.

Finder's fees totaling $28,400 (8% of the gross proceeds received from purchasers introduced to the Company by the finders) were paid to arm's length parties in connection with the private placement.

On January 26, 2011, the Company announced that it had entered into a sponsorship agreement with PI Financial Corp. ("PI"), pursuant to which PI has agreed to act as the Company's sponsor in connection with a proposed listing of the Company's common shares on the TSX Venture Exchange (the "Exchange"). Pursuant to the sponsorship agreement, PI will conduct standard due diligence on the Company's business with a view to preparing the necessary sponsorship reports for timely submission to the Exchange in connection with an application for listing on the Exchange. Submission of a sponsorship report will be subject to completion of satisfactory due diligence by PI.

On April 12, 2011, the Company announced the appointment of David B. Finn to the Board of Directors of the Company. Mr. Finn is a Petroleum Consultant with over 30 years consulting experience in oil and gas property evaluations. He graduated from the British Columbia Institute of Technology with a Diploma in Natural Gas and Petroleum Technology in 1969 and upon graduation was employed by Amoco Canada Petroleum Company Ltd. From there he returned to University majoring in physical sciences, then re-entering the oil and gas industry with the British Columbia Petroleum Corporation where he monitored natural gas performance of northeastern British Columbia gas fields. In 1978 Mr. Finn began his career in the consulting business with the predecessor company of Gilbert Laustsen Jung Associates Ltd. In 1980 he co-established and was a partner in the Vancouver based oil and gas consulting firm, Esau Finn Associates Ltd. which until 1989 served the resource and financial community of Vancouver. The firm provided oil and gas technical reports in support of securities and banking requirements; acquisition/disposition appraisals; independent opinion of drilling prospects; and monitoring of oil and gas operations of junior oil and gas companies. Areas of exposure include continental U.S.A., the western Canadian sedimentary basin as well as limited offshore evaluations. In 1990 Mr. Finn became an independent oil and gas consultant, primarily contracting his services to Gilbert Laustsen Jung Associates Ltd. in Calgary, until returning to Vancouver in 2002, where he continues to provide his consulting services.

On May 3, 2011, the Company extended the expiry date of 1,000,000 share purchase warrants (the "Warrants") exercisable to purchase one common share of the Company at an exercise price of $0.30 per share from the original expiry date of May 14, 2011 to May 14, 2012. The Warrants were issued in May 2008 in connection with a non-brokered private placement financing with an original term of three years.

On June 1, 2011, the Company announced that it had completed a non-brokered private placement by the issuance of 300,000 units of the Company at a subscription price of $0.25 per unit for gross proceeds of $75,000. Each unit consists of one common share and one share purchase warrant of the Company. Each warrant is exercisable into one additional common share of the Company at an exercise price of $0.35 per share for a period of 24 months from the closing date.

The proceeds from the sale of the units under the private placement will be used for exploration drilling activities in the Landrose area of west-central Saskatchewan and for general working capital.

On June 9, 2011, the Company announced that it had received formal TSX approval for the listing of its common shares on the TSX Venture Exchange. The Company's common shares commenced trading on the TSX Venture Exchange on Friday, June 10, 2011 under the symbol "AHU". The Company's common shares were de-listed from the Canadian National Stock Exchange concurrent with the listing of its shares on the TSX Venture Exchange.

SUMMARY OF QUARTERLY RESULTS

The following is selected financial information from the Company's eight most recently completed fiscal quarters:

RESULTS OF OPERATIONS – PERIOD ENDED JUNE 30, 2011

	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**	**3rd Qtr Ended 03-31-10**	**2nd Qtr Ended 12-31-09**	**1st Qtr Ended 9-30-09**
Total Revenues	$243,348	$247,882	$615,584	$246,917	$Nil	$Nil	$Nil	$Nil
Operating Profit (Loss)	($176,746)	($55,481)	$141,398	$11,576	($61,482)	($104,075)	($47,342)	($41,184)
Operating Profit (Loss) Per Share	($0.01)	$0.00	$0.01	$0.00	($0.01)	($0.01)	($0.00)	($0.00)
Total Net (Loss) Gain	($137,006)	($55,481)	$141,398	$11,576	($447,171)	($104,075)	$27,658	($22,809)
Total Net Profit (Loss) Per Share	($0.01)	$0.00	$0.01	$0.00	($0.04)	($0.01)	($0.00)	($0.00)

RESULTS OF OPERATIONS – YEAR ENDED JUNE 30, 2011

The Company successfully drilled its first heavy oil well located in the Lloydminster area of western Saskatchewan in July, 2010. The well cost was $360,854 to drill and equip and after adding $11,351 in asset retirement costs, the total cost was $372,205. The well started to produce heavy oil in August, 2010 and 11 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 $349,186 to drill and equip and after adding $10,830 in asset retirement costs, the total cost was $360,016. The wells started to produce heavy oil in October, 2010 and 9 months worth of oil production has been recorded.

The Company's net loss for the year ended June 30, 2011 was $39,513 or $0.01 per share compared to a net loss of $546,397 or $0.05 loss per share for the year ended June 30, 2010. The significant changes during the current year compared to the prior year are as follows:

During the first year of production, petroleum revenue during the year ended June 30, 2011 was $1,353,731. After deducting royalties of $415,135, production and transportation costs of $203,256 and depletion and amortization of $426,664, net petroleum production revenue of $308,676 was recorded.

Consulting fees increased $35,462 to $90,615 during the year ended June 30, 2011 from $55,153 during the year ended June 30, 2010 were due to the payment of the Company's sponsorship fees associated with PI Financial.

Rent of $19,489 stayed constant as compared to the previous year as per the Company's lease agreement.

Management fees increased $21,000 to $63,000 during the year ended June 30, 2011 from $42,000 during the year ended June 30, 2010 as a result of the renegotiated management agreement.

Promotion expenses decreased $27,459 to $400 during the year ended June 30, 2011 from $27,859 during the year ended June 30, 2010 as no promotion expenses were incurred.

Professional fees increased $64,640 to $108,945 during the year ended June 30, 2011 from $44,305 during the year ended June 30, 2010 due to increased legal fees incurred for the Company's oil and gas acquisitions and for the submissions of the listing application with the TSX Venture Exchange.

Filing fees increased $30,647 to $46,150 during the year ended June 30, 2011 from $15,503 during the year ended June 30, 2010 due to increased fees for the listing application with the TSX Venture Exchange.

Non- cash financing fees of $48,188 were recorded during the year ended June 30, 2011 due to the extension of 1,000,000 share purchase warrants from an expiry date of May 14, 2011 to May 14, 2012.

Stock-based compensation expense totaling $970, a non-cash item, was incurred during the year ended June 30, 2011 for the 100,000 stock options granted to a consultant of which 25,000 stock options vested on November 11, 2010 as compared to $32,335 for the year ended June 30, 2010.

The net loss of $39,513 during the year was less than the previous year loss of $546,397 as a write-off of mineral property costs of $373,189 was recorded in the prior year.

At June 30, 2011, Arctic Hunter held assets recorded at $870,540 including $75,029 in restricted cash that must be spent on Canadian mineral exploration expenses before December 31, 2011, $354,068 in cash, $15,263 in prepaid expense, $120,623 in receivables from its oil and gas operations and $305,557 in property, plant and equipment.

RESULTS OF OPERATIONS – THREE MONTH PERIOD ENDED JUNE 30, 2011

The Company's net operating loss for the three month period ended June 30, 2011 was $176,746 or $0.01 per share compared to a net loss of $61,482 or $0.01 loss per share for the three month period ended June 30, 2010. The significant expenses during the current period are as follows:

During the three month period ended June 30, 2011, petroleum revenue was $243,348. After deducting royalties of $55,726, production and transportation costs of $33,046 and depletion and amortization of $145,916, net petroleum production revenue of $8,660 was recorded.

Consulting fees of $30,026 during the three month period ended June 30, 2011 included $7,500 paid to the Vice-President of Corporate Development and $19,000 due to the payment of the Company's sponsorship fees with PI Financial.

Filing fees of $23,082 during the three month period ended June 30, 2011were mainly due to the payment of the Company's $20,000 listing application fee to the TSX Venture Exchange.

Rent of $4,817 stayed constant as compared to the previous period as per the Company's lease agreement.

Management fees were $19,500 during the three month period ended June 30, 2011 in accordance with the management agreement.

Director fees were $6,000 during the three month period ended June 30, 2011 in accordance with the April 1, 2011 agreement.

Professional fees of $51,360 during the three month period ended June 30, 2011 and were due to $4,500 paid to the Chief Financial Officer, $31,860 in legal fees incurred for the listing application with the TSX Venture Exchange and the estimated June 2011 audit cost of $15,000.

Non- cash financing fees of $48,188 were recorded during the three month period ended June 30, 2011 due to the extension of 1,000,000 share purchase warrants from an expiry date of May 14, 2011 to May 14, 2012.

FINANCIAL AND OPERATING SUMMARY
TABLE A - OPERATIONS BY QUARTER (August to June 2011)

All production is conventional heavy oil

Production and per share	**Q4 2011**	**Q3 2011**	**Q2 2010**	**Q1 2010**
Production - total barrels	3,469	4,379	10,521	4,560
Production - bbls/ day	**38**	**49**	**114**	**76**
Heavy oil revenue	243,348	247,882	615,584	246,917
Royalties	(55,726)	(64,096)	(230,908)	(64,405)
Production & transportation	(33,046)	(75,719)	(59,576)	(34,915)
Operating net back	154,576	108,067	325,100	147,597
General and administrative	(185,406)	(109,905)	(56,187)	(36,431)
Corporate net back	(30,830)	(1,838)	268,913	111,166
Depletion & accretion	(145,916)	(53,643)	(127,515)	(99,590)
Other (expenses) revenue	39,740	-	-	-
Income (loss) for the period	**(137,006)**	**(55,481)**	**141,398**	**11,576**
Basic and diluted income (loss) per share	**(0.01)**	**0.00**	**0.01**	**0.00**
Royalties as % of petroleum revenue	**23**	**26**	**38**	**26**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	70.15	56.61	58.51	54.15
Royalties	(16.06)	(14.64)	(21.95)	(14.12)
Production and transportation	(9.53)	(17.29)	(5.66)	(7.66)
Operating net back	**44.56**	**24.68**	**30.90**	**32.37**
General and administrative	(53.45)	(25.10)	(5.34)	(7.99)
Depletion & accretion	(42.06)	(12.25)	(12.12)	(21.84)
Other revenue	11.46	-	-	-
Income (loss) for the period	(39.49)	(12.67)	13.44	2.54
Funds (invested in) petroleum properties	**(215,752)**	**(7,078)**	**(243,605)**	**(243,605)**

FINANCIAL AND OPERATING SUMMARY
TABLE C – BALANCE SHEET

	Q4 2011	Q3 2011	Q2 2010	Q1 2010
Net cash	429,097	376,387	421,408	159,824
Total assets	870,540	868,541	932,977	377,190
Total liabilities	190,167	126,811	250,766	134,503
Shareholders equity	680,373	741,730	682,211	242,687
SHARES				
Basic outstanding	14,985,000	14,685,000	13,920,000	12,700,000
Weighted average	13,718,658	14,625,500	12,746,413	12,700,000

OPERATING RESULTS FOR THREE MONTHS ENDED JUNE 2011

- **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 cost $360,854 to drill and equip. The well started to produce in August and 11 months worth of production has been attained and recorded for the newly operating well. The well started producing at an initial gross rate of approximately 80 bbls/d. The Company controlled the well production in accordance with established good oil field practices and the average production over the quarter ended June 30, 2011 was approximately 26 bbls/d net after payout to the Company.

In April 2011, the $360,854 cost associated to drill and equip the C-12 well was recovered by the Company and in accordance with the agreement, the Company’s working interest is now 50%.

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 $171,784 to drill and equip. The Company controlled the well production in accordance with established good oil field practices and the average production over the quarter ended June 30, 2011 was approximately 4 bbls/d (2 bbls/d net after payout to the Company).

The $171,784 cost associated to drill and equip the C-11 well has $59,276 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 Companies 50% cost of the well was $177,402 to drill and equip. The Company controlled the well production in accordance with established good oil field practices and the average production over the quarter ended June 30, 2011 was approximately 8 bbls/d net after payout to the Company.

In March 2011, the $177,402 cost associated to drill and equip the C-14 well was recovered by the Company and in accordance with the agreement, the Company’s working interest is now 25%.

The average realized price per bbl for the fourth quarter ended June 30, 2011 was $70.15 per bbl as compared to $56.61 per bbl in the previous quarter. The realized average corporate prices per bbl during the quarter was higher than normal due to high demand for heavy oil and higher 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 year. 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 increased in Q 4 2011 over prior quarters primarily due to a transportation disruption resulting from the nine week maintenance shut-down of a pipeline that carries Canadian crude oil to refineries in the U.S. Midwest. Further short term maintenance shut-downs of this pipeline followed in January and February 2011, with product delivery rates having been largely restored by late April. As a result, the Company realized an average oil price of $70.15 per bbl in Q4 2011 as compared to $56.61 per bbl in Q3 2011.

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

Q4 2011 overall royalty burden averaged 23% compared to 26% in Q3 2011. Q4 2011 includes the lower production volumes from the wells. 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 fourth quarter ended June 30, 2011.

- **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 2011and 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 10 added $372,205 to Property, Plant and Equipment which includes $11,351 in asset retirement costs and these costs were subjected to depletion. This property included 16,000 bbls (8,000 net bbls) of proven 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 10 added $176,938 to Property, Plant and Equipment which includes $5,154 in asset retirement obligations and these costs were subjected to depletion. This property included 16,000 bbls (4,000 net bls) of proven 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 10 added $183,078 to Property, Plant and Equipment which includes $5,676 in asset retirement obligations and these costs were subjected to depletion. This property included 12,000 bbls (3,000 net bbls) of proven 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 energy companies may choose 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 will generate a more realistic estimate of real depletion.

OUTLOOK

The Company continues to strengthen its financial position with stable production volumes, strong oil prices and control over costs.

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 June 30, 2011, production was slowed due to lower output from the C-11 well and was averaging approximately 38 bbls per day with an average price of $70.15 per bbl.

Current production is expected to increase with the restoration of lost production due to harsher than normal winter weather conditions. Cold winter weather led to well shutdowns, minor maintenance issues associated with the colder weather, and reduced daily average production rates from the Landrose wells. Well production was reduced in order to maximize long-term reservoir exploitation in the Landrose area.

In April 2011, the $360,854 cost associated to drill and equip the C-12 well was recovered and in accordance with the agreement, its future working interest converted to 50%.

In March 2011, the $177,402 cost associated to drill and equip the C-14 well was recovered and in accordance with the agreement, its future working interest converted to 25%.

The $171,784 cost associated to drill and equip the C-11 well has $59,276 remaining on its payout. After payout, the Company's future working interest will convert to 25%.

LIQUIDITY AND CAPITAL RESOURCES

Arctic Hunter Uranium 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 an Alberta based, junior heavy oil producer. Combined production flow from the C-11, C-12 and C-14 wells over the quarter ended June 30, 2011 was approximately 38 bbls/d gross of heavy oil (34 bbls/d net after payout to the Company) on its Landrose, Saskatchewan 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.

During the period, the Company issued an aggregate of 560,000 flow-through units at a price of $0.25 per unit, 1,425,000 non flow-through units at a price of $0.20 per unit, and 300,000 non flow-through units at a price of $0.25 per unit for total gross proceeds of $500,000.

At June 30, 2011, the Company had $429,097 cash on hand, of which $75,029 is restricted for Canadian exploration expenditures that must be incurred before December 31, 2011. The remaining cash of $354,068 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 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 $63,000 (2010 - $42,000) have been recorded for the year ended June 30, 2011.

During the year ended June 30, 2011, the Company paid consulting fees of $10,000 (2010 - $23,000) to a former director.

Effective December 1, 2010, the Company agreed to pay $1,500 per month to the Chief Financial Officer for accounting services. Professional fees of $10,500 (2010 - $Nil) have been recorded for the year ended June 30, 2011.

Effective December 1, 2010, the Company agreed to pay $2,500 per month to the Vice-President of Corporate Development. Consulting fees of $17,500 (2010 - $Nil) have been recorded for the year ended June 30, 2011.

Effective April 1, 2011, the Company agreed to pay $2,000 per month to a Director. Director fees of $6,000 (2010 - $Nil) have been recorded for the year ended June 30, 2011.

At June 30, 2011, the Company had a receivable of $33,669 (2010: $Nil) from a company with common directors for the net revenue in two producing wells in Landrose, Saskatchewan.

During the year ended June 30, 2011, the Company recovered $Nil (2010 - $18,375) rent from a company with common directors.

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 1,000,000 common shares upon the exercise of share purchase warrants at a price of $0.30 per share until May 14, 2011. On May 3, 2011, the Company extended the expiry date of these share purchase warrants to May 14, 2012,

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 3,000,000 common shares upon the exercise of share purchase warrants at a price of $0.25 per share until October 4, 2012,

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 130,000 common shares upon the exercise of share purchase warrants at a price of $0.35 per share until December 22, 2011,

g) up to 330,000 common shares upon the exercise of share purchase warrants at a price of $0.25 per share until December 22, 2011,

h) up to 150,000 common shares upon the exercise of share purchase warrants at a price of $0.35 per share until December 30, 2011,

i) up to 382,500 common shares upon the exercise of share purchase warrants at a price of $0.25 per share until January 7, 2012,

j) 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.

INVESTOR RELATIONS

All investor relations activity is currently being provided by the management of 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.

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.

FUTURE ACCOUNTING PRONOUNCEMENTS

International financial reporting standards (“IFRS”)

In January 2006, the Canadian Accounting Standards Board adopted a strategic plan, which includes the decision to move financial reporting for Canadian publicly accountable enterprises to a single set of globally accepted standards, IFRS, as issued by the International Accounting Standards Board. The effective implementation date of the conversion from Canadian generally accepted accounting principles (“Canadian GAAP”) to IFRS is 1 January 2011, with an effective transition date of 1 January 2010 for financial statements prepared on a comparative basis. The Company is engaged in an assessment and conversion process and expects to be ready for the conversion to IFRS in advance of 1 January 2011.

The Company’s approach to the conversion to IFRS includes three phases.

- Phase one, an initial general diagnostic of its accounting policies and Canadian GAAP relevant to its financial reporting requirements to determine the key differences and options with respect to acceptable accounting standards under IFRS. This phase was completed in late 2009.
- Phase two, an in-depth analysis of the IFRS impact in those areas identified under phase one. This phase commenced in 2010. A summary of this analysis is provided in Table 1 below.
- Phase three, the implementation of the conversion process, including the completion of the opening balance sheet as at 1 July 2010 together with related discussion and notes, will be carried out in the first quarter of 2011.

At this point, the Company's IT accounting and financial reporting systems are not expected to be significantly impacted. Further, the Company has in place internal and disclosure control procedures to ensure continued effectiveness during this transition period.

The above comments, including the summary in Table 1, should not be considered as a complete and final list of the changes that will result from the transition to IFRS as the Company intends to maintain a current and proactive approach based on changes in circumstances and no final determinations have been made. In addition, the accounting bodies responsible for issuing Canadian and IFRS accounting standards have significant ongoing projects that could impact the Company's financial statements as at 1 January 2011 and in subsequent years, including projects regarding financial instruments and joint venture accounting. In addition, there is an extractive industries project currently underway that will lead to more definitive guidance on the accounting for exploration and evaluation expenditures, although this is still in the discussion paper stage and may not be completed for some time. The Company is continuing to monitor the development of these projects and will assess their impact in the course of its transition process to IFRS.

Table 1. Summary of financial statements impact on transition from Canadian GAAP to IFRS.

Key Area	Canadian GAAP (as currently applied)	IFRS	Analysis and preliminary conclusions
Property, plant and equipment (PP&E")	PP&E is recorded at historical cost. Depreciation is based on their useful lives after due estimation of their residual values. Oil & gas resource interests are depleted using the unit-of-production method.	PP&E can be recorded using the cost (on transition to IFRS, the then fair value can be deemed to be the cost) or revaluation models. Depreciation must be based on the useful lives of each significant component within PP&E. Companies may include probably reserves for the computation of depletion.	PP&E will likely continue to be recorded at their historical costs due to the complexity and resources required to determine fair values on an annual basis. Based on an analysis of PP&E and its significant components, the Company has determined that no change to their useful lives is warranted and, therefore, depreciation expense will continue to be calculated using the same rates under IFRS. As probable reserves are determined based on a probability of recovery of 50% or more, this broader depletion base under IFRS will generate a more realistic estimate of real depletion.
Oil and gas properties	Exploration, evaluation and development costs are capitalized when incurred. They are amortized on the basis of production or written off when the prospect is no longer deemed prospective or is abandoned.	IFRS has limited guidance with respect to these costs and currently allows exploration and evaluation costs to be either capitalized or expensed.	The existing accounting policy is likely to be maintained.
Asset retirement obligations ("ARO")	Canadian GAAP limits the definition of ARO to legal obligations. ARO is calculated using a current credit-adjusted, risk-free rate for upward adjustments, and the original credit-adjusted, risk-free rate for downward revisions. The original liability is not adjusted for changes in current discount rates.	IFRS defines ARO as legal or constructive obligations. ARO is calculated using a current pre-tax discount rate (which reflects current market assessment of the time value of money and the risk specific to the liability) and is revised every reporting period to reflect changes in assumptions or discount rates. IFRS requires that, on transition, the net book value of the asset related to ARO be adjusted on the basis of the ARO balance existing at inception.	The broadening of this definition is unlikely to cause a significant change in the Company's current estimates. The Company is in the final stages of quantifying the impact of this change on the ARO provision. The Company expects to rely on the IFRS 1 exemption which allows a company to use current estimates of future reclamation costs and current amortization rates to determine the net book value on transition to IFRS.
Impairment of long lived assets	Impairment tests of its long-term assets are considered annually based on indications of impairment. Impairment tests are generally	Impairment tests of "cash generating units" are considered annually in the presence of indications of impairment.	Assets will continue to be grouped under the Company's various mining operations. Impairment tests using discounted values could generate a greater likelihood of write

	done on the basis of undiscounted future cash flows. Write-downs to net realizable values under an impairment test are permanent changes in the carrying value of assets.	Impairment tests are generally carried out using the discounted future cash flows. Write downs to net realizable values under an impairment test can be reversed if the conditions of impairment cease to exist.	downs in the future. Potential significant volatility in earnings could arise as a result of the difference in the treatment of write-downs.
Stock-based compensation	Stock-based compensation is determined using fair value models (e.g. Black-Scholes) for equity-settled awards and the intrinsic model for cash-settled awards. The Company recognizes stock-based compensation on straight line method and updates the value of the options for forfeitures as they occur.	Stock-based compensation is determined using fair value models for all awards. However, upon settlement, cash-settled awards are adjusted to the value actually realized (intrinsic model). Under IFRS, stock-based compensation is amortized under the graded method only. In addition, the Company is required to update its value of options for each reporting period for expected forfeitures.	The utilization of fair value models for cash-settled awards will change the estimate of the related liability while the awards remain outstanding and create greater volatility in earnings until the awards are settled. The Company expects to record an IFRS income statement and balance sheet adjustment at 1 July 2010.
Income taxes	There is no exemption from recognizing a deferred income tax for the initial recognition of an asset or liability in a transaction that is not a business combination. The carrying amount of the asset or liability acquired is adjusted for the amount of the deferred income tax recognized. All deferred income tax assets are recognized to the extent that it is “more likely than not” that the deferred income tax assets will be realized.	A deferred income tax is not recognized if it arises from the initial recognition of an asset or liability in a transaction that is not a business combination, and at the time of the transaction affects neither accounting profit nor taxable profit. A deferred tax asset is recognized if it is “probable” that it will be realized.	The Company does not expect the difference in recognition of deferred income tax to have any significant change in the future. “Probable” in this context is not defined and does not necessarily mean “more likely than not”. The Company is in the final stages of quantifying the impact of this difference.

The above assessment and conclusions are based on the analysis completed by the Company as of the date of this report and may be subject to change between now and 1 January 2011.

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)