United Hunter Oil & Gas Corp.
Management's Discussion and Analysis

The following Management's Discussion and Analysis ("MD&A") of the financial position of United Hunter Oil & Gas Corp. (the "Company") should be read in conjunction with the Company's unaudited condensed interim financial statements for the 3 months ended June 30, 2011. The information provided is as of August 29, 2011. These documents, and additional information about the Company, are available at www.sedar.com. Unless otherwise noted, dollar amounts are expressed in US dollars. References to C$ means Canadian dollars.

Description of Business
United Hunter Oil & Gas Corp. (the "Company") is engaged in the exploration and development of oil and gas properties. The Company owns a 65% indirect Membership Interest in Excelaron, LLC ("Excelaron"), an exploration stage company operating in San Luis Obispo, California. The Company also owns interests in oil and gas properties in Alberta. The Company's shares are listed on the TSX Venture Exchange under the symbol UHO.

Huasna Property
The Company holds an indirect 65% indirect interest in Excelaron, which holds a 100% interest in an oil and natural gas property consisting of 260 acres on the western edge of the Huasna Basin, an existing California Department of Oil, Gas and Geothermal Resources designated oilfield within the Meridian Anticline located in Arroyo Grande, California. The Company will carry out exploration and development of oil and gas properties held by Excelaron pursuant to the terms of a joint operating agreement. Its joint venture partner in Excelaron is Australia Oil Company.

Geology Description
The onshore portion of the Santa Maria Basin is a triangular shaped structural basin located north of Los Angeles in the state of California and bounded by the Santa Ynez Mountains to the south and the San Rafael Mountains to the north.

The basin contains Cenozoic Miocene to Quaternary strata that pinch out against the older strata of the mountain ranges to the south and north. An unconformity at the top of the Mesozoic strata indicates a period of widespread emergence and erosion during the middle Tertiary period. Sedimentation commenced again when Lower Miocene strata were deposited during a period of regional crustal extension. During much of the ensuing Miocene time the Monterey Formation was deposited, the major reservoir zone and only source rock in the basin. The Monterey Formation ranges in thickness from 1,000 to 4,000 feet and consists primarily of organic rich clastic poor strata, more calcareous in the lower section and increasingly cherty and siliceous in the upper section. These are deeper water deposits as sea level was high at this time.

Much of the oil in the Santa Maria Basin is trapped in west-northwest trending faulted anticlines. In the Monterey Formation, the reservoirs are very thick fractured sections of chert, siliceous shale and dolomite. The oil is usually heavy and typically ranges from 10° to 20° API. Matrix porosity is typically about 10% to 35% but the permeability within the matrix is negligible. The recoverable oil is predominantly located in the fracture system for which the porosity ranges from 1% to 2% or less, but permeability can be very large.

The Huasna Field is located in the northern portion of the Santa Maria Basin and is a mapped surface anticlinal feature with tar sealed Monterey Formation as the outcropping formation. Structural closure is 450 acres and the first well drilled into the structure, Scherer-Dickes #1, was perforated from 900 to 2200 feet in the Monterey Formation.

Resource Estimates
The following information is contained in Evaluation of Contingent Resources for the Huasna Field, San Luis Obispo County, California, USA dated October 27, 2010 that was prepared by Gaffney Cline & Associates Inc. ("GCA Report"). The GCA Report was prepared in accordance with National Instrument 51-101 and is available at www.sedar.com

The oil gravity in the Monterey shale accumulation is presumed to be 13° API and its exploitation will be facilitated by application of an enhanced recovery scheme by hot water injection. Under Excelaron's scheme concept hot water would be injected to raise the reservoir temperature and increase oil mobility, plus provide a displacement mechanism for the oil.

GCA made volumetric estimates of the Discovered Petroleum Initially-In-Place "PIIP" using the existing well information and references appropriate field analogs. GCA gives expected recoveries at Huasna of 4-6% of the Discovered PIIP for the hot water stimulation process that UHO plans to test and implement at Huasna. According to GCA's estimates, the P50 Discovered PIIP is 96 MMBbl with net UHO recoverable of 2.7 MMBbl; the P90 Discovered PIIP is 44.6 MMBbl with net UHO recoverable of 1.2 MMBbl, and the P10 Discovered PIIP is 174 MMBbl with net UHO recoverable of 5.1MMBbl. The Discovered PIIP estimates are for the entire field area. Net UHO recoverable volumes are based on the assumption that UHO's 65% interest in the 160 acre project area will apply to the remainder of the Huasna field. The volumes have been reduced for royalties. Recoverable volumes are classified by GCA as Contingent Resources as of July 31st 2010 and estimated in accordance with the reserve and resource definitions set out in the Canadian Oil and Gas Evaluation Handbook COGEH, which also forms part of Canadian National Instrument 51-101.Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources"). Discovered Petroleum Initially-In-Place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

As indicated above, the 12 Well Project contains contingent resources, the main contingencies are:

Establishing production in commercial quantities using primary or secondary methods;
Securing the necessary permits to develop the field;
Securing funds and services in order to drill and complete new wells;
Constructing processing and transportation facilities; and
Securing sales contracts for the oil that can be produced.

Development Plan
The Company plans to drill 12 new wells within the next 5 years. The initial Phase of the 12 well plan is a 4 well Pilot Program consisting of up to four vertical producers that will be drilled and operated with a rental boiler/treater generator for about six months to examine the potential for commercial production. After the completion of the well pilot program a full analysis of the field's commercial potential will be conducted. The Pilot Program will be used to obtain new subsurface information and to initiate production using intermittent hot water injection. In this approach, hot water will be injected in each well for intermittent periods followed by periods of production. These first 4 wells will be drilled and completed as vertical or near vertical, and will be logged using appropriate modern logs. Fresh cores and fluid samples will be taken and analyzed. The Company plans to use reservoir modeling that will involve construction of a geological model and reservoir simulation using thermal and dual permeability formulations to assess the recovery potential and to optimize vertical and horizontal spacing in conjunction with injection rates and schedule.

The next development phase consists of an additional 8 wells (plus a water disposal well) and a permanent facility. The Company will adopt a maximum recovery by the least possible surface impact principle. In practice, vertical and directional wells will be drilled from central locations that at subsurface will project an optimal spacing pattern. Hot water injection will be applied at about 2,400 bbl/day rates. The hot water will be injected in each well sequentially allowing wells to alternate through injection and production cycles. Recent fluid sampling has shown that increasing the temperature of the fluid by modest amounts reduces oil viscosity. Applied at intervals no thicker than 300-400 feet is typically accomplished by injecting at the deepest interval first and then plugging and later completing upwards at shallower depths.

The major obstacle in carrying out this development concept is securing the necessary permits from the regulatory authorities, which requires environmental impact compliance and approval. The Draft Environmental Impact Report (DEIR) was released by the San Luis Obispo County Planning and Building Department on June 19th and was circulated for 45 days ending on August 5th. The California Environmental Quality Act Guidelines requires a 45-day public review period. Interested parties can provide comments on the environmental document that will then be addressed by the County's consultant, Marine Research Specialists, in the Final EIR. The Final EIR has been tentatively scheduled to be in front of the Planning Commission November 10th. The Final EIR will then be presented to the San Luis Obispo Board of Supervisors for the final ruling on the Project Permit.

Atlee Buffalo Property
The Company owns a 95% working interest in a portion of the suspended Alberta Mannville G oil field ("Atlee Buffalo"). The Atlee Buffalo Mannville G pool was discovered in 1980 and, at the time of acquisition, was suspended. This first acquisition in Alberta is part of the Company's overall mandate and growth strategy for Alberta to re-enter suspended vertical wells in low risk oil prospects. During November 2010, the first well was re-completed and during March 2011, a single well battery site was constructed and the well tied in, with the intent to do a long term production test. The long term production test was completed and a total of 2,777 barrels of oil has been produced up to August 14, 2011 and the well currently is producing at a rate of 20 bopd. A second well was re-completed and a single well battery was constructed and the well tied in and will soon be on production.

Woodbend Leduc Property

Pursuant to a farm-in agreement with MEC Operating Company ULC, the Company has the right to earn PN&G right within the Wabamum Formation under 4 sections of land (2,560 acres) at the Leduc Woodbend area of Alberta. The terms of this farm-in agreement allows the Company to earn 71.8% by paying 71.8% subject to a 10% GORR payable to MEC. In the event that MEC converts its 10% GORR to a 30% working interest after re-completion the Company will have paid 71.8% of the recompletion costs to earn 50%. This farm-in agreement is again part of the Company's overall mandate and growth strategy for Alberta to re-enter suspended vertical wells in low risk oil projects. During December 2010, the first well was re-completed and swabbed oil and water. This well is being tied into existing facilities.

Porter Ranch Property

The Company owns a owns 45% interest in a joint venture with Australia Oil Company called Alamo Creek LLC, which leased 4,068 acres (Porter Ranch) within the Huasna Basin, adjacent to Santa Maria Basin in California. The leases were briefly explored in the 1980's by Phillips Petroleum Company ("PPC") who drilled one well and completed extensive roadwork and wells pads for two additional well locations prior to abandoning the project due to depressed oil prices. There has been no subsequent exploration since that time. The only well PPC drilled in 1984 tested oil from 3 separate zones and then abandoned and plugged this well. Adjacent wells have tested oil ranging from light (30 API) to heavy (15 – 18 API), some with associated gas and numerous surface oil seeps. Within the leased area there are currently 2 anticlinal structures which have been only tested at their extremities. The forward work program includes acquiring all historical well and seismic data prior to the possible acquisition of new seismic data over the anticlines. Based on this information, up to 3 exploration wells may be drilled. During the second quarter of 2011, the Company leased an additional adjacent 4,982 acres for a net cost of $27,224. The Company also paid net $53,000 for the license for 91 miles of 2D seismic data which cover the Porter Ranch from ConocoPhillips. These seismic lines are currently being reprocessed and evaluated.

Risks and Uncertainties

The Company is subject to various risks and uncertainties due the nature of the business and its present stage of development. Certain of these risks and uncertainties are set out below and under the heading "Risk Factors" in the Company's Annual Information Form for the year ended December 31, 2010 which is available on SEDAR at www.sedar.com.

Liquidity

The Company is in the exploration stage and has minimal revenues. As at June 30, 2011, the Company had working capital of $502,500, cash flow used in operating activities of $1,450,302, loss of $961,055, and accumulated deficit of $2,632,282. While the Company has sufficient funds to meet its current commitments, the Company will require additional funding to fund its operations and for the exploration of its oil and gas properties. Without additional funding, there is substantial doubt as to the Company's ability to continue as a going concern. Within the next 12 months, the Company will be seeking to raise the necessary capital to meet its funding requirements. Although the Company has been successful in raising funds to date, there can be no assurance that additional funding will be available. These funds will be required to finance capital and operating expenditures in Huasna if permits are approved.

Permits

The operations of the Company require licenses and permits from various governmental authorities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits, including conditional use permits that may be required to carry out exploration and development of its projects, in particular, Huasna.

Exploration

The Company is exposed to the inherent risks associated with oil and gas exploration and development, including the uncertainty of oil and gas resources and their development into recoverable reserves; the uncertainty as to potential project delays from circumstances beyond the Company's control; and the timing of production; as well as title risks, risks associated with joint venture agreements and the possible failure to obtain mining licenses.

Commodity price

The Company is exposed to commodity price risk with respect to oil and gas prices. A significant decline in oil and gas commodity prices may affect the Company's ability to obtain capital for the exploration and development of its interest in oil and gas properties.

Results of Operations

	3 months ended June 30, 2011 $	2010 $	6 months ended June 30, 2011 $	2010 $
Revenues				
Oil sales	68,640	-	110,332	-
Expenses				
Operating and transportation	148,513	-	187,429	-
Depletion	34,824	-	57,335	-
Professional fees	58,197	-	84,125	-
Management fees	24,375	40,625	48,750	40,625
Salaries and wages	126,009	2,879	285,629	2,879
Consulting fees	42,349	158,153	161,164	158,153
Stock-based compensation	118,860	43,593	259,855	43,593
Premises	10,003	8,703	31,885	8,703
General and administrative	12,251	12,380	26,078	12,380
Public company costs	8,448	10,711	17,324	10,711
Investor relations	39,286	14,147	110,360	14,147
Travel	16,587	9,121	32,014	9,121
Permitting	28,170	12,847	28,170	12,847
Transaction costs	-	1,226,384	-	1,226,384
Interest income	(5,635)	-	(12,506)	-
Loss on revaluation of warrant liability	(335,676)	(1,255,817)	(106,478)	(1,255,817)
Foreign exchange gain	(13,199)	56,406	(78,436)	56,406
	313,361	340,132	1,132,699	340,132
Loss and comprehensive loss before income taxes	(244,722)	(340,132)	(1,022,367)	(340,132)
Future income tax reduction	30,815	-	61,312	-
Loss and comprehensive loss	(213,907)	(340,132)	(961,055)	(340,132)

The Company was inactive until April 23, 2010, the date that it acquired an indirect 65% interest in Excelaron. Accordingly, the results of operations for the comparative period are for the period April 23, 2010 to June 30, 2010.

Results of operations for the 3 and 6 months ended June 30, 2010 reflect one-time transaction costs of $1,226,384 related to the acquisition of Excelaron, which was offset by a loss on revaluation of warrant liability of $1,255,817.

On March 4, 2011, the Company commenced production at a one well at Atlee Buffalo and generated revenue from oil sales.

Summary of Quarterly Results

	Q3 2009 $ (note 1)	Q4 2009 $ (note 1)	Q1 2010 $ (note 2)	Q2 2010 $ (note 2)	Q3 2010 $ (note 2)	Q4 2010 $ (note 2)	Q1 2011 $ (note 2)	Q2 2011 $ (note 2)
Revenue	-	-	-	-	-	-	41,692	110,332
Income (loss) - Total	-	(75,000)	-	(340,132)	(608,602)	(396,220)	(747,148)	(213,907)
Per share (note 3)	-	-	-	-	(0.01)	-	(0.01)	-

Note 1: Prepared in accordance with Canadian GAAP.
Note 2: Prepared in accordance with IFRS.
Note 3: Basic and diluted

The Company was inactive until April 23, 2010, the date that it acquired an indirect 65% interest in Excelaron.

Liquidity & Capital Resources
The Company is in the exploration stage and has minimal revenues. As at June 30, 2011, the Company had working capital of $502,500 (December 31, 2010 - $1,794,771), cash flow used in operating activities of $1,450,302, loss of $961,055, and accumulated deficit of $2,632,282. In the 6 months ended June 30, 2011, working capital declined as a result of operations using cash of $1,450,302 and expenditures on exploration and evaluation of $586,508.

While the Company has sufficient funds to meet its current commitments, the Company will require additional funding to fund its operations and for the exploration of its oil and gas properties. Without additional funding, there is substantial doubt as to the Company's ability to continue as a going concern. Within the next 12 months, the Company will be seeking to raise the necessary capital to meet its funding requirements. Although the Company has been successful in raising funds to date, there can be no assurance that additional funding will be available. These funds will be required to finance capital and operating expenditures in Huasna if the permits are approved.

Huasna capital expenditures
It has been estimated that the initial pilot scheme for the development plan, consisting of four vertical hot water injector/producers, plus surface equipment, would cost $1,875,000, of which, $800,000 will be paid by the Company, with all costs for the development of the development plan thereafter being paid 65% by the Company and 35% by its joint venture partner. The Project will be subject to a 12.5% basic overriding royalty plus an additional 5% of net revenue after energy-related lifting costs.

For the expanded development plan it has been estimated that a vertical hot water injection well will cost $300,000 to drill and the hot water boiler and associated facilities will cost $1,000,000.

Total capital expenditures for a fully exploited Project as described would be $14,175,000 ($9,870,000 net to the Company), comprised of the following:

(a) the well pilot program, consisting of four vertical hot water injector/oil producers which would be drilled and operated with a rental boiler/treater generator for about six months to examine the potential for commercial production, potentially a water disposal well will also be drilled if there is a requirement to dispose of produced formation water; and
(b) phase 2, consisting of 8 vertical,inclined or horizontal wells and a disposal well (if not drilled during the pilot program), building of water boiler/treator facilities.

Total abandonment and restoration liabilities have been estimated at $350,000 ($227,500 net to the Company).

Of the first $1,875,000 required for the development plan, the Company has already advanced $1,075,000 and the remaining $800,000 will be advanced at such time as Excelaron secures its conditional use permits for its planned operations on its oil and natural gas properties. In the event that Excelaron does not secure such permits or the Company does not pay the $800,000, the 40% Membership Interest will be reduced to a 15% Membership Interest in Excelaron. The Company has also agreed to pay a shareholder of UHC a 5% assignable gross overriding royalty on all amounts received, directly or indirectly, by the Company that can be attributed to its 65% Membership Interest in Excelaron.

Related Party Transactions

	6 months ended	June 30,	Outstanding as at June 30,	December 31,
	2011	2010	2011	2010
	$	$	$	$
Rent				
Paid in respect of rent for office premises in Toronto to GM Partners, a company controlled by Bradley Griffiths, a former director	12,648	–	–	–
Paid in respect of rent for office premises in Calgary to Impel	7,050	–	–	–
Office				
Paid in respect of office administration services to Shirley Mejia de Halleran, spouse of Arthur Halleran	2,535	–	–	–
Paid respect of office services to Impel, a company controlled by Peter Rudakis, an officer	2,525	–	–	–

International Financial Reporting Standards ("IFRS")

Implementation of International Financial Reporting Standards ("IFRS")

The Company's IFRS conversion plan as detailed in our Annual MD&A is now complete, except for the review phase which will continue throughout 2011.

The Canadian Accounting Standards Board required all public companies to adopt IFRS for interim and annual financial statements relating to their first fiscal years beginning on and after January 1, 2011. The Company's interim consolidated financial statements for the 6 months ended June 30, 2011 have been prepared in accordance with IFRS including comparative amounts shown for 2010.

Although IFRS has a conceptual framework that is similar to previous Canadian GAAP, there are significant differences in recognition, measurement and disclosure. The transition to the IFRS framework has resulted in several changes to accounting policies that impact financial reporting. The following are the more significant accounting differences:

Impairment of Non-Current Assets

Under Canadian GAAP, long-lived asset impairment testing is done using a two-step approach whereby long-lived assets are first tested for recoverability based on the undiscounted cash flows they are expected to generate. If the undiscounted cash flow expected to be generated is higher than the carrying amount, then no further analysis is required to be recorded. If the undiscounted cash flow is lower than the carrying amount of the assets, the assets are written down to their estimated value. Under IFRS, impairment testing is done using a one-step approach for both testing and measurement of impairment, with asset carrying amounts compared directly with the higher of fair value less costs to sell and value in use (which uses discounted cash flows). This may result in more frequent write-downs where carrying amounts of assets were previously supported under Canadian GAAP on an undiscounted cash flow basis, but could not be supported on a discounted basis. However, the extent of any asset write-downs may be partially offset by the requirements under IFRS to reverse any previous impairment losses where circumstances have changed such that the impairments are reduced. The previous Canadian GAAP did not permit reversal of impairment losses

Consideration payable

The Company is committed to pay $800,000 at such time as Excelaron secures its conditional use permits for its planned operations on its oil and gas properties.

Under IFRS, a contingent liability, a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the entity, is recognized as of the acquisition date if it is a present obligation that arises from past events and its fair value can be measured reliably.

Under Canadian GAAP, when the outcome of a contingency cannot be determined without reasonable doubt, a contingent liability is not recognized until the contingency is resolved and the consideration is issued.

Warrant liability

The Company's common share purchase warrants denominated in Canadian dollars are considered to the derivative instruments. The warrants liability is measured at fair value on initial recognition and subsequently at each balance sheet date, with changes in the fair value recognized in the statement of loss.

Stock-based compensation

Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate.

Under Canadian GAAP, the Company recognized stock-based compensation related to issue of stock options on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple.

Other Considerations of the Changeover from Canadian GAAP to IFRS

Internal Control Activities

The Company has applied its existing internal control framework to the IFRS changeover process and there have not been any significant changes as a result. All accounting policy changes have been reviewed by senior management and the audit committee.

Information Technology and Systems
The primary information technology and systems impact of the conversion to IFRS is on the Company's consolidation system used to prepare its consolidated financial statements where the Company has implemented the changes necessary to collect and consolidate the information required to complete the consolidation process in accordance with IFRS.

Business activities
The implementation of IFRS did not impact any employee compensation plans or key ratios and the Company does not have any debt covenants. In addition, the transition to IFRS did not have a significant impact on internal controls except as noted above.

Review
The review phase involves continuous monitoring of changes in IFRS. IFRS accounting standards and the interpretation thereof are constantly evolving. As a result, the Company will continue to monitor and evaluate IFRS accounting developments. The review phase will continue throughout 2011.

IFRS 1: First-time Adoption of International Financial Reporting Standards
IFRS 1 provides entities adopting IFRS for the first time with a number of optional and mandatory exceptions, in certain areas, to the general requirement for full retrospective applications of IFRS. The purpose of these options is to provide relief to companies and simplify the conversion process by not requiring recalculation of information that may not exist or may not have been collected at the time of the original transaction. Mandatory exceptions provide that changes to estimates previously made are not permitted. The estimates previously made by the Company under Canadian GAAP have not been revised for application of IFRS except where necessary to reflect any changes resulting from differences in accounting policies.

To complete the implementation of IFRS, management has analyzed the various transitional exemptions available to the Company under IFRS 1. The Company has implemented the following optional IFRS 1 exemptions:

Business Combinations
IFRS 1 allows that a first-time adopter may elect not to apply IFRS 3 Business Combinations (IFRS 3) retrospectively to business combinations prior to the date of transition. The Company has elected to not restate any past business combinations and to apply IFRS prospectively from the transition date. As such, Canadian GAAP balances relating to business combinations entered into before the date of transition have been carried forward without adjustment.

Stock-based Payments
The Company has elected to apply the transitional exemption which allows the Company not to restate the accounting for its share based payments under IFRS 2 to awards that were granted after November 7, 2002 that vested before the later of (a) the date of transition to IFRSs and (b) January 1, 2005. Accordingly, there has been no restatement of the Company's accounting under Canadian GAAP for stock options.

Fair value as deemed cost
The Company may elect among two options when measuring the value of its asset under IFRS. It may elect, on an asset by asset basis, to use either historical cost as measured under retrospective application of IFRS or fair value of an asset at the opening balance sheet date. The Company has elected to use historical cost for its assets.

Adoption of IFRS 6
The Company has elected to adopt the provisions of IFRS 6, which allow the Company to continue with the current accounting policies followed under Canadian GAAP regarding the accounting for exploration and evaluation expenditures.

New Accounting Pronouncements
As out in note 2 to the Company's interim consolidated financial statements, the International Accounting Standards Board has issued a number of new accounting pronouncements which are effective for periods after January 1, 2013. The Company has not yet assessed the impact of these standards or whether it will adopt the standards early where permitted.

Critical Accounting Estimates
The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments with respect to certain estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results, however, could differ significantly from those based on such estimates and assumptions.

During the fiscal periods presented, management has made a number of significant estimates and valuation assumptions including estimates of the useful life of capital assets, the recoverability of investments and mineral assets, the fair value of stock based compensation and warrants. These estimates and valuation assumptions are based on present conditions and management's planned course of action as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Exploration and evaluation

The Company's policy is to capitalize expenditures related to the acquisition, exploration and development of its exploration properties net of recoveries and carry these expenditures as assets until production commences. The Company's recorded value for exploration and evaluation costs is based on historical costs and does not necessarily reflect present or future values. If an exploration project is successful, the related exploration and evaluation costs will be amortized using the unit-of-production method following the commencement of production over the estimated economic life of the project. If an exploration project is abandoned, continued exploration is not planned in the foreseeable future or when other events and circumstances indicate that the carrying amount may not be recovered, the accumulated costs and expenditures are written down to the net recoverable amount at the time the determination is made.

At each quarter end senior management reviews the carrying value of the exploration and evaluation to consider whether there are any conditions that may indicate impairment. Where estimates of future cash flows are available, a reduction in the carrying value is recorded to the extent the net book value of the investment exceeds the estimated future cash flows. Where estimates of the future cash flows are not available and where other conditions suggest impairment, management assesses if the carrying value can be recovered and provides for impairment, if so indicated.

Assessment of recoverability of future income taxes

The determination of the ability of the Company to utilize tax loss carry-forwards to offset future income tax payable requires management to exercise judgment and make certain assumptions about the future performance of the Company. Management is required to assess whether it is probable that the Company would benefit from these prior losses and other future tax assets. Changes in economic conditions, metal prices and other factors could result in revisions to the estimates of the benefits to be realized or the timing of utilizing losses. Currently the Company has recorded a valuation allowance against its carry-forward tax losses. If the valuation allowance is changed in a period, an expense or benefit must be included within the tax provision on the consolidated statement of comprehensive income (loss).

Environmental and land reclamation costs

The fair value of liabilities for asset retirement obligations will be recognized in the period in which they are incurred. Currently there are no asset retirement obligations. As the development of any project progresses, the Company will assess whether an asset retirement obligation ("ARO") has arisen. At the point where such a liability arises, the financial statement adjustment required will be to increase the project's carrying value and ARO obligation by the discounted value of the total liability. Thereafter, the Company will be required to record a charge to income each year to accrete the discounted ARO obligation amount to the final expected liability.

Warrant liability

The Company's common share purchase warrants denominated in Canadian dollars are considered to the derivative instruments. The warrants liability is measured at fair value on initial recognition and subsequently at each balance sheet date, with changes in the fair value recognized in the statement of loss. To determine the fair value, the Company uses the Black-Scholes option pricing model that requires input of management's assumptions on the expected volatility of the Company's share price, expected option life, a risk-free rate of return and expected dividend yield. The use of different assumptions regarding these factors could have a significant impact on the amount of the warrant liability.

Stock-based compensation

The Company recorded stock-based compensation based on an estimate of the fair value on the grant date of stock options issued. To determine the fair value, the Company uses the Black-Scholes option pricing model that requires input of management's assumptions on the expected volatility of the Company's share price, expected option life, a risk-free rate of return and expected dividend yield. The use of different assumptions regarding these factors could have a significant impact on the amount of stock based compensation expense.

Financial Instruments and Other Instruments

Fair value
Fair value represents the amount at which a financial instrument could be exchanged between willing parties, based on current markets for instruments with the same risk, principal and remaining maturity. Fair value estimates are based on quoted market values and other valuation methods.

The carrying value of cash and cash equivalents, accounts receivables, due from joint venture partner and accounts payable and accrued liabilities approximates fair value due to the short-term nature of these financial instruments.

Risk management
The Company's financial instruments are exposed to certain financial risks, including currency risk, credit risk, liquidity risk and interest rate risk.

Currency risk
The Company's expenditures are denominated in both US and Canadian dollars. As at March 31, 2011, the Company had the following monetary assets and liabilities denominated in Canadian dollars:

	C$
Assets	
Cash and cash equivalents	1,495,747
Accounts receivable	92,456
Due from joint venture partner	36,694
	1,624,625
Liabilities	
Accounts payable and accrued liabilities	173,850
	1,450,775

As at June 30, 2011, a 5% change in the exchange rate between the US dollar and Canadian dollar would have resulted in an impact on operations of $72,539.

Credit risk
Credit risk is the risk of a loss if a counterparty to a financial instrument fails to meet its contractual obligations. The Company's credit risk is attributable to cash and cash equivalents, accounts receivable and due from joint venture partner.

Cash and cash equivalents of $1,599,007 are held in deposits with high credit quality Canadian financial institutions. Accounts receivable of $96,645 represents refunds claimed for Harmonized Sales Tax and due from joint venture partner of $36,694 is in good standing.

Liquidity risk
Liquidity risk is the risk that the Company will not be able to meet is financial obligations as they come due. The Company manages its liquidity risk through the management of its capital structure. Accounts payable are all due within the next year.

Interest rate risk
Interest rate risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is not exposed to interest rate risk due to the short-term nature of its financial instruments.

Other Information

Additional Disclosure for Venture Corporations without Significant Revenue

The following tables sets forth a breakdown of material components of the general and administration costs, capitalized or expensed exploration and development costs of the Company:

	6 months ended June 30, 2011 $	2010 $
General and administrative expenses		
Bank charges	2,055	–
Insurance	3,814	–
Office	19,492	12,380
Telephone	717	–
	26,078	12,380

	December 31, 2010 $	Additions $	Transfer to property, plant and equipment $	June 30, 2011 $
Exploration and evaluation				
Huasna	5,319,341	40,312	–	5,359,653
Atlee Buffalo	476,300	329,216	(805,516)	–
Leduc Woodbend	332,142	98,034	–	430,176
Porter Ranch	50,000	66,861	–	116,861
	6,177,783	534,424	(805,516)	5,906,691

Disclosure of Outstanding Share Data (as at August 29, 2011)

Shares
Authorized:
Unlimited number of common shares, no par value.

Unlimited number of preference shares, issuable in series. The preference shares are issuable in series and may be issued in one or more series, from time to time, by the directors of the Company. The directors of the Company are authorized to fix, among other things, the designation, preferences, rights and restrictions attaching to each series of preference shares, in addition to the entitlement of each series of preference shares to receive the assets of the Company available on a liquidation, dissolution or winding-up of the Company. The preference shares are entitled to preference over the common shares and any other shares ranking junior to the such preference shares with respect to, among other things, payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Company. Unless the rights attaching to the preference shares state otherwise, each preference share carries one vote at all meetings of shareholders, other than at meetings of the holders of the common shares meeting separately as a class.

Outstanding:
120,302,722 common shares.
No preference shares are outstanding.

Escrow:
26,606,116 common shares are subject to escrow agreements, of which, 40% of the escrowed common shares have been released and an additional 15% will be released on each of November 6, 2011, May 6, 2012, November 6, 2012 and May 6, 2013.

24,541,106 common shares are subject to escrow agreements, under which, 20% of the escrowed common shares have been released, and 10% will be released on November 6, 2011, 15% will be released May 6, 2012 and November 6, 2012, and 40% will be released on May 6, 2013.

Warrants
The following warrants are outstanding:

Exercise price	Number of warrants	Expiry date
C$0.40	22,500,000	April 23, 2012
C$0.20	3,600,000	April 23, 2012
	26,100,000	

In the event that the Company's common shares trade at or above C$0.80 for more than 20 consecutive days, the 22,500,000 warrants must be exercised after written notice is provided by the Company or the warrants will expire.

Stock options
Authorized:
The Company may grant options to its directors, officers, employees and consultants to acquire up to10% of the issued and outstanding common shares at the time of the grant.

Outstanding:

Exercise price	Number of options	Expiry date
C$0.15	8,350,000	May 12, 2015
C$0.15	1,000,000	July 20, 2015
C$0.15	425,000	August 31, 2015
	9,775,000	

Forward-looking Statements

Forward-looking statements include, but are not limited to, statements with respect to: the focus of capital expenditures; the sale, farming in, farming out or development of certain exploration properties using third party resources; the impact of changes in petroleum and natural gas prices on cash flow; drilling plans; processing capacity; operating and other costs; the existence, operation and strategy of the commodity price risk management program; the approximate and maximum amount of forward sales; the Company's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom; the Company's goal to sustain or grow production and reserves through prudent management and acquisitions; the emergence of accretive growth opportunities; the Company's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets; development costs and the source of funding thereof; the quantity of petroleum and natural gas resources or reserves; treatment under governmental regulatory regimes and tax laws; liquidity and financial capital; the impact of potential acquisitions and the timing for achieving such impact; expectations regarding the ability to raise capital and continually add to reserves through acquisition and development; the performance characteristics of the Company's petroleum and natural gas properties; and realization of the anticipated benefits of acquisitions and dispositions. The Company undertakes no obligation to update such forward-looking statements or information if circumstances or management's estimates or opinions should change, unless required by law.

Some of the risks and other factors, which could cause results to differ materially from those expressed in the forward-looking statements include, but are not limited to: general economic conditions in Canada, the United States of America and globally; supply and demand for petroleum and natural gas; industry conditions, including fluctuations in the price of petroleum and natural gas; governmental regulation of the petroleum and natural gas industry, including income tax, environmental and regulatory matters; fluctuation in foreign exchange or interest rates; risks and liabilities inherent in petroleum and natural gas operations, including exploration, development, exploitation, marketing and transportation risks; geological, technical, drilling and processing problems; unanticipated operating events which can reduce production or cause production to be shut-in or delayed; the ability of our industry partners to pay their proportionate share of joint interest billings; failure to obtain industry partner and other third party consents and approvals, when required; stock market volatility and market valuations; competition for, among other things, capital, acquisition of reserves, processing and transportation capacity, undeveloped land and skilled personnel; the need to obtain required approvals from regulatory authorities; and the other factors considered under "Risk Factors" in the AIF.

In addition, other factors not currently viewed as material could cause actual results to differ materially from those described in the forward-looking statements.

Readers should be aware that historical results are not necessarily indicative of future performance. No assurance can be given that any events anticipated by the forward looking statements or information will transpire or occur, or if any of them do, what benefits the Company may derive therefrom.

Statements relating to "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the described resources exist in the quantities predicted or estimated, and can be profitably produced in the future. There is no certainty that it will be commercially viable to produce any portion of the resources described in this MD&A.