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 audited consolidated financial statements for the year ended December 31, 2011. The information provided is as of April 30, 2012. 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 joint venture interest in Excelaron, LLC ("Excelaron"), an exploration stage company based in San Luis Obispo, California; a 25% joint venture interest in Alamo Creek Oil LLC ("Alamo"), an exploration stage company based in San Luis Obispo, California; and interests in oil and gas properties in Alberta. The Company's shares are listed on the TSX Venture Exchange under the symbol UHO.

Overall Performance

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 the Company plans to test and implement at Huasna. According to GCA's estimates, the P50 Discovered PIIP is 96 MMBbl with net recoverable to the Company 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 recoverable to the Company 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 31, 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 19, 2011 and was circulated for 45 days ending on August 5, 2011. 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 Environment Impact Review ("FEIR"). The Planning Commission ("PC") reviewed the DEIR on February 23, 2012 and March 8, 2012. The San Luis Obispo County Planning Commission voted 4-1 to deny the Huasna project from proceeding in the Huasna Valley. The decision was appealed to the San Luis Obispo County Board of Supervisors for the final decision. The meeting for the Board of Supervisors will be on May 15, 2012.

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. A second well was re-completed and a single well battery was also constructed.

Both wells averaged a combined $80,000 cash flow per month for January, February and March, 2012. Total cash flow to end of March 2012 from the two Atlee Buffalo wells is over $550,000.

Oil reserves
The Company's reserves evaluated by Ryder Scott Company conform to definitions set for in the Canadian Oil and Gas Evaluation Handbook as referenced in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities.* A summary of oil reserves as at December 31, 2011 are as follows:

	Barrels
As at December 31, 2011	
Proved developed producing	7,321
Proved developed non-producing	–
Proved undeveloped	–
Total proved	7,321
Probable	16,207
Total proved and probable	23,527

Net present value before income taxes

Discount rate	**5%**	**10%**	**15%**	**20%**
As at December 31, 2011				
Proved developed producing	341,312	336,618	331,674	326,550
Proved developed non-producing	–	–	–	–
Proved undeveloped	–	–	–	–
Total proved	341,312	336,618	331,674	326,550
Probable	470,746	432,363	396,462	362,964
Total proved and probable	812,058	752,363	728,126	689,515

The estimated net present value of future net revenues presented in the table above does not necessarily represent the fair market value of the Company's reserves.

Woodbend Leduc Property
The Company disposed of its interests in the Wabamum at Woodbend Leduc tested with the Company's first re-entered test well. The interest was sold for a cash payment and a Gross Overriding Royalty – disclosure of both restricted by a confidentiality clause in the sales agreement**.** 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.

Porter Ranch Property
The Company acquired a 45% joint venture interest in Alamo Creek Oil LLC ("Alamo"). At that time, Alamo leased 4,068 acres adjacent to the Santa Maria Basin and south east of the Company's Huasna property ("Porter Ranch"). The property was 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. Alamo has 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.

In the second quarter of 2011, Alamo leased an additional 4,983 acres increasing the acreage under lease to 9,051 acres. Subsequent to December 31, 2011, the Company declined to pay its share of a cash call and its joint venture interest in Alamo was reduced from 45% to 25%.

Risks and Uncertainties

The Company is subject to various risks and uncertainties due to the nature of the business and its present stage of development.

Liquidity

The Company has financed its operations through the issue of equity. At December 31, 2011, the Company had a working capital deficit of $494,959 and for the year ended December 31, 2011, the Company incurred losses of $2,789,448 and negative cash flows from operations of $2,068,139. The working capital deficiency and losses limit the Company's ability to fund operations and the exploration and development of oil and gas properties. In addition, there is uncertainty whether the Company will secure conditional use permits for its planned exploration and development of the Huasna property and in the event the conditional use permits are secured, the Company is committed to make a payment of $800,000. As a result, there is significant doubt about the Company's ability to continue as a going concern.

Since December 31, 2011, the Company has had sufficient cash flows from operations to meet is obligations as they come due, however, the continuation of the Company as a going concern is dependent on completing an equity financing and securing conditional use permits for its Huasna property. The Company will work to raise the necessary financing and secure the conditional use permits, but the outcome of these efforts cannot be predicted at this time.

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.

Summary Annual Information

	Years ended December 31		
	2011	**2010**	**2009**
	$	**$**	**$**
Revenue	315,196	–	–
Net loss			
Total	2,789,448	1,829,515	75,000
Per share (basic and diluted)	0.02	0.02	–
Total assets	6,140,745	9,447,805	1,202,252

The Company was a capital pool corporation and was inactive until April 23, 2010, the date that it acquired an indirect 65% interest in Excelaron. Accordingly, the results of operations for 2010 are for the period April 23, 2010 to December 31, 2010.

Results of Operations

	3 months ended December 31, 2011 $	2010 $	Years ended December 31, 2011 $	2010 $
Revenues				
Oil sales	45,611	-	315,196	-
Expenses				
Operating and transportation	97,328	-	394,880	-
Depletion	59,324	-	210,843	-
Impairment losses	735,130	-	735,130	-
Professional fees	69,580	101,737	165,487	101,737
Management fees	-	5,000	48,750	70,000
Salaries and wages	171,225	133,841	586,037	276,600
Consulting fees	10,466	90,339	192,060	565,879
Stock-based compensation	2,984	159,172	365,156	394,094
Premises	(943)	29,406	44,629	51,000
General and administrative	13,466	(17,198)	57,139	31,617
Public company costs	6,879	8,866	25,544	24,879
Investor relations	4,584	89,472	155,808	141,006
Travel	20,129	39,776	69,375	77,386
Permitting	122,245	4,740	193,642	25,630
Transaction costs	-	1,226,384	-	1,226,384
Interest income	(760)	(19,366)	(15,774)	(19,366)
Gain on revaluation of warrant liability	(34,562)	-	(432,389)	(1,206,084)
Loss on sale of exploration and evaluation	326,829	-	326,829	-
Foreign exchange gain	(12,184)	12,495	(18,502)	68,753
	1,591,720	1,864,664	3,104,644	1,829,515
Net loss and comprehensive loss	(1,546,109)	(1,864,664)	(2,789,448)	(1,829,515)

The Company was a capital pool corporation and 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 December 31, 2010.

Revenues

The Company commenced production at two wells at Atlee Buffalo and generated revenue from oil sales.

	Years ended December 31, 2011	2011
Oil sales	$315,196	–
Barrels	4,363	–
Average price per barrel	$72.25	–

Operating and transportation and depletion

	Years ended December 31, 2011	2010
Operating and transportation	$394,880	–
Depletion	$210,843	–
Barrels	4,363	–
Operating and transportation per barrel	$90.51	–
Depletion per barrel	$48.33	–

Operating and transportation per barrel exceeded average revenue per barrel due to additional costs required during the initial startup of the two wells at Atlee Buffalo.

Impairment losses
An impairment loss of $735,130 was recorded with respect to Atlee Buffalo based on the estimated net present value of cash flows of estimated reserves discounted at 10%.

Transaction costs. Results of operations for the year ended December 31, 2010 reflect one-time transaction costs of $1,226,384 related to the acquisition of Excelaron.

Gain on revaluation of warrant liability
Warrants representing an obligation to issue shares for a price that is not in the Company's functional currency that do not qualify as a rights offering to all shareholders of that class, are classified as a derivative liability and measured at fair value at each balance sheet date with changes recognized in the statement of loss and comprehensive loss. Accordingly, a gain of $432,389 was recorded upon the revaluation of the warrants to fair value.

Loss on sale of exploration and evaluation
A loss of $326,829 was recorded on the sale of Leduc Woodbend.

Summary of Quarterly Results (prepared in accordance with IFRS)

	Q1 2010 $ (note 1)	**Q2 2010 $** (note 2)	**Q3 2010 $**	**Q4 2010 $** (note 3)	**Q1 2011 $** (note 4)	**Q2 2011 $**	**Q3 2011 $**	**Q4 2011 $** (note 5)
Revenue	–	–	–	–	41,692	68,640	159,253	45,611
Income (loss)								
Total	–	466,766	(690,612)	(1,605,669)	(777,645)	(244,722)	(220,971)	(1,546,109)
Per share-basic and diluted	–	–	–	(0.02)	(0.01)	–	–	(0.01)

Note 1: The Company was a capital pool corporation and was inactive until April 23, 2010, the date that it acquired an indirect 65% interest in Excelaron.
Note 2: Income included a gain on the revaluation of warrant liability of $836,340.
Note 3: Loss included transaction costs of $1,226,384 related to the Amalgamation.
Note 4: Loss included a loss on the revaluation of warrant liability of $229,198.
Note 5: Loss included impairment loss of $735,130 and loss on the sale of exploration and evaluation of $326,829.

Liquidity & Capital Resources
The Company has financed its operations through the issue of equity. At December 31, 2011, the Company had a working capital deficit of $494,959 and for the year ended December 31, 2011, the Company incurred losses of $2,789,448 and negative cash flows from operations of $2,068,139. The working capital deficiency and losses limit the Company’s ability to fund operations and the exploration and development of oil and gas properties. In addition, there is uncertainty whether the Company will secure conditional use permits for its planned exploration and development of the Huasna property. In the event the conditional use permits are secured, the Company is committed to make a payment of $800,000 as a capital contribution to Excelaron in accordance with the terms of the Company’s acquisition of Excelaron. As a result, there is significant doubt about the Company’s ability to continue as a going concern.

Since December 31, 2011, the Company has had sufficient cash flows from operations to meet is obligations as they come due, however, the continuation of the Company as a going concern is dependent on completing an equity financing and securing conditional use permits for its Huasna property. The Company will work to raise the necessary financing and secure the conditional use permits, but the outcome of these efforts cannot be predicted at this time.

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 or inclined 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 65% Membership Interest will be reduced to a 35% 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

	Year ended December 31, 2011 $	**Outstanding at December 31, 2011 $**
Legal fees		
Paid to Aird & Berlis LLP, of which, Daniel Bloch, a director, is a partner	84,172	43,526
Rent		
Paid in respect of rent for office premises in Toronto to GM Partners, a company controlled by Bradley Griffiths, a former director	12,643	–
Paid in respect of rent for office premises in Calgary to Impel Corporation, a company controlled by Peter Rudakas, an officer	17,700	–
Office		
Paid in respect of salary paid to Shirley Mejia de Halleran, spouse of Arthur Halleran	31,859	–

International Financial Reporting Standards ("IFRS")

In previous years, the Company prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The Company adopted IFRS effective January 1, 2011 and the Company's consolidated financial statements for the year ended December 31, 2011 and 2010 and consolidated statement of financial position as at January 1, 2010 have been prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards.*

The audited consolidated financial statements set out significant accounting policies in accordance with IFRS in Note 4 and reconciliations between Canadian GAAP and IFRS in note 15. The following paragraphs provide summary of the impact of the transition from Canadian GAAP to IFRS.

First-time adoption exemptions applied

IFRS 1 allows first-time adopters certain exemptions from retrospective application of certain IFRS. The Company has applied the following optional exemptions to full retrospective application of IFRS and has made the following adjustments to transition from Canadian GAAP to IFRS:

Historical cost as deemed cost
The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS at the amount determined under Canadian GAAP as at January 1, 2010. Cost included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of proved and probable reserves values as at January 1, 2010. The exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation assets at the amount that was recorded under Canadian GAAP.

Business Combinations
IFRS 1 allows for IFRS 3, *Business Combinations*, to be applied retrospectively or prospectively. The Company elected to adopt IFRS 3 prospectively to business combinations subsequent to the date of transition. Accordingly, all business combinations after January 1, 2010 will be accounted for in accordance with IFRS 3.

Share-based payment transactions
IFRS 1 allows that full retrospective application may not apply to certain share-based instruments depending on the grant date and vesting terms. The Company has elected to not apply IFRS 2 to share-based payments granted after November 7, 2002 that vested before the date of transition to IFRS. Accordingly, the Company has applied IFRS 2 only to unvested stock options outstanding as at January 1, 2010.

Impact of the transition from Canadian GAAP to IFRS

Contingent liability
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 resulting from a business combination is recognized 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.

Warrants
The Company has outstanding common share purchase warrants denominated in Canadian dollars.

Under IFRS, an obligation to issue shares for a price that is not in the Company's functional currency, and that does not qualify as a rights offering to all shareholders of that class, must be classified as a derivative liability and measured at fair value at each balance sheet date with changes recognized in the statement of comprehensive income.

Under Canadian GAAP, warrants were classified as a equity and changes in fair value were not recognized.

Share based payments
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.

Deferred income taxes
Under IFRS, there is a provision for an exemption from recording a deferred income tax liability on initial recognition when the acquisition of assets is not a business combination and, at the time of the transaction, affects neither accounting profit/loss nor tax profit/loss. As the acquisition of Excelaron meets the IFRS exemption criteria, the Company did not recognize the deferred income tax liability.

Under Canadian GAAP, the Company recognized deferred income tax on temporary differences arising on acquisition of assets where the carrying amount of the assets acquired exceeded the tax base.

Other considerations of the transition from Canadian GAAP to IFRS

Internal control
The transition from Canadian GAAP to IFRS did not have a significant impact on internal controls.

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 in accordance with IFRS.

Business activities
The transition from Canadian GAAP to IFRS did not impact any employee compensation plans or key ratios and the Company does not have any debt covenants.

New standards and interpretations not yet adopted

A number of new standards, amendments to standards and interpretations are effective for periods beginning on or after January 1, 2013.

IFRS 9, Financial Instruments ("IFRS 9")
IFRS 9 addresses classification and measurement of financial assets and replaces the multiple category and measurement models in IAS 39 for debt instruments with a new mixed measurement model having only two categories: amortized cost and fair value through profit or loss. IFRS 9 also replaces the models for measuring equity instruments, and such instruments are either recognized at fair value through profit or loss or at fair value through other comprehensive income. Where such equity instruments are measured at fair value through other comprehensive income, dividends are recognized in profit or loss to the extent not clearly representing a return of investment; however, other gains and losses (including impairments) associated with such instruments remain in accumulated comprehensive income indefinitely.

Requirements for financial liabilities were added in October 2010 and they largely carried forward existing requirements in IAS 39, *Financial Instruments - Recognition and Measurement*, except that fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

IFRS 10, Consolidation ("IFRS 10")
IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12 Consolidation—Special Purpose Entities and parts of IAS 27 Consolidated and Separate Financial Statements.

IFRS 11, Joint Arrangements ("IFRS 11")
IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers.

IFRS 12, Disclosure of Interests in Other Entities ("IFRS 12")
IFRS 12 establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities.

IFRS 13, Fair Value Measurement ("IFRS 13")
IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement.

Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

Amendments to other standards
In addition, there have been amendments to existing standards, including IAS 27, Separate Financial Statements (IAS 27), and IAS 28, Investments in Associates and Joint Ventures (IAS 28). IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10-13.

Effect of new standards
IFRS 9, IFRS 10 and IFRS 11 are expected to have an effect on the consolidated financial statements of the Company. The Company has not determined the extent of the impact these standards and does not plan to early adopt these new standards.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires the Company's management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Judgments
The key judgments made in applying accounting policies that have the most significant effect on the amounts recognized in these consolidated financial statements are as follows:

Identification of cash generating units
Cash generating units ("CGUs") are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into cash generating units requires significant judgment and interpretations with respect to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

Fair value of warrant liability
The fair value of the warrant liability is not observable in an active market, and as such, is determined using valuation methods. The Company uses judgment to select the method used to determine the fair value and uses directly and indirectly observable inputs.

Estimates
Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment within the next financial year are as follows:

Impairment of exploration and evaluation
Expenditures on exploration and evaluation are initially capitalized with the intent to establish commercially viable reserves. The Company makes estimates about future events and circumstances in determining whether the carrying amount of exploration and evaluation exceeds its recoverable amount.

Estimates of oil and natural gas reserves
Depletion and depreciation as well as the amounts used in impairment calculations are based on estimates of oil reserves. Reserves estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. At least once per year, a reserves estimate is prepared by independent qualified reserves evaluators. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

Recoverable amounts of CGUs
The recoverable amount of a CGU used in the assessment of impairment of property, plant and equipment is the greater of its value in use ("VIU") and its fair value less costs to sell ("FVLCTS"). VIU is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves. FVLCTS refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal.

Recoverable amounts of the Company’s CGUs were based on their estimated VIU. The key assumptions and estimates of the value of oil reserves are valid at the time of reserves estimation and market assessment and are subject to change as new information becomes available. Changes in international and regional factors including supply and demand of commodities, inventory levels, drilling activity, currency exchange rates, weather, geopolitical and general economic environment factors may result in significant changes to the estimated recoverable amounts of CGUs.

Decommissioning liabilities
Decommissioning liabilities are estimated based on the Company’s net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years, based on current legal and constructive requirements and technology. The estimated liabilities and actual costs may change significantly due to changes in regulations, technology, timing of the expenditure, and the discount rates used to determine the net present value of the obligations.

Deferred income taxes
Deferred income tax assets and liabilities are measured using enacted or substantively enacted tax rates at the reporting date in effect for the period in which the temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in tax rates is recognized as part of the provision for income taxes in the period that includes the enactment date. The recognition of deferred income tax assets is based on the assumption that it is probable that taxable profit will be available against which the deductible temporary differences can be utilized.

Warrant liability and share-based compensation
The Company uses the Black-Scholes option pricing model in determining warrant liability and share-based compensation, which requires a number of assumptions to be made, including the risk-free interest rate, expected life, forfeiture rate and expected share price volatility. Consequently, the actual share-based compensation expense may vary from the amount estimated.

Financial Instruments and Other Instruments

Determination of fair values
A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Cash and cash equivalents, accounts receivable, due from joint venture partner, accounts payable and accrued liabilities, due to joint venture partner and consideration payable
The fair values of cash and cash equivalents, accounts receivable, due from joint venture partner, accounts payable and accrued liabilities, due to joint venture partner and consideration payable are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2011, December 31, 2010 and January 1, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity.

Exploration and evaluation and property, plant and equipment
The Company estimated the VIU to determine the recoverable amounts of the Company's CGUs for impairment testing based on consideration of the following:

- net present value of proved plus probable reserves using a pre-tax discount rate of 10% as determined by independent qualified reserves evaluators;
- management's estimate of the fair value of undeveloped land; and
- a review of the values indicated by the metrics of recent market transactions of similar assets within the oil and gas industry.

The market value of other items of exploration and evaluation and property, plant and equipment is based on the quoted market prices for similar items.

Warrant liability and stock options
The fair value of warrant liability and employee stock options is measured using a Black-Scholes option pricing model. Measurement inputs include share price on grant date, exercise price, expected volatility (based on historical volatility of securities of comparable companies), weighted average expected life and forfeiture rate (both based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

Classification of fair value of financial instruments
The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument

- Level 1 - quoted prices in active markets for identical assets and liabilities;
- Level 2 - inputs, other than the quoted prices included in Level 1, that are observable for the asset or liability, either directly or indirectly;
- Level 3 - inputs for the asset or liability that are not based on observable market data

The carrying value of cash and cash equivalents, due from joint venture partner, accounts payable and accrued liabilities, due to joint venture partner and consideration payable approximate fair value due to their short-term nature. Other financial instruments measured at fair value classified using the fair value hierarchy:

As at December, 31, 2011	**Carrying value $**	**Fair value $**	**Level 1 $**	**Level 2 $**	**Level 3 $**
Derivative financial liabilities					
Warrant liability	–	–	–	–	–

As at December, 31, 2010	**Carrying value $**	**Fair value $**	**Level 1 $**	**Level 2 $**	**Level 3 $**
Derivative financial liabilities					
Warrant liability	432,389	432,389	–	–	432,389

Financial risk management
The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities, including credit risk, liquidity risk and market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors oversees management's establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

Credit risk
Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. Credit risk arises principally from the Company's cash balances and receivables. The maximum exposure to credit risk is equal to the balances of cash and cash equivalents and due from joint venture partner.

The Company's limits its exposure to credit risk on its cash and cash equivalents by holding its cash balances in deposits with a high credit quality Canadian chartered bank.

Liquidity risk
Liquidity risk is the risk that the Company will encounter difficulty in meeting its financial liabilities that are settled in cash or other financial assets. The Company's approach to managing liquidity risk is to ensure, as far as possible, that it will have sufficient liquidity to meet is liabilities as they come due. The amounts for accounts payable and accrued liabilities, due to joint venture partner and consideration payable are due in less than one year.

Market risk
Market risk is the risk that changes in market prices, such as equity prices, foreign exchange rates, and interest rates will affect the Company's income or the value of its financial instruments.

Equity price risk
Equity risk arises from the effect of changes in the market value of the Company's common shares on the determination of fair value of the warrant liability as calculated using the Black-Scholes option pricing model.

Currency risk
Currency risk arises from the Company's financial instruments and purchases that are denominated in a currency other than the US dollar, the Company's functional currency. As at December 31, 2011, the Company had the following monetary assets and liabilities denominated in Canadian dollars:

	C$
Assets	
Cash and cash equivalents	377,910
Accounts receivable	92,160
	470,070
Liabilities	
Accounts payable and accrued liabilities	188,134
Due to joint venture partner	18,436
	206,570

As at December 31, 2011, a 5% change in the exchange rate between the US dollar and Canadian dollar would have resulted in an impact on operations of $13,175.

Interest rate risk
The Company's exposure to interest rate risk is limited due to the short-term nature of its financial instruments.

Other Information

Additional Disclosure for Venture Corporations without Significant Revenue

The following tables set out a breakdown of material components of the general and administration costs and capitalized exploration and evaluation of the Company:

General and administration costs

	Years ended December 31, 2011 $	2010 $
Bank charges	4,036	–
Insurance	20,136	7,770
Office	32,967	23,847
	57,139	31,617

Exploration and evaluation

	Huasna $	Atlee Buffalo $	Leduc Woodbend $	Porter Ranch $	Total $
Balance, January 1, 2010	1,200,000	–	–	–	1,200,000
Acquisition	3,300,499	105,140	–	50,000	3,455,639
Additions	164,639	371,160	332,142	–	867,941
Balance, December 31, 2010	4,665,138	476,300	332,142	50,000	5,523,580
Additions	23,299	1,187,551	189,282	6,861	1,406,993
Disposition	–	–	(521,424)	–	(521,424)
Transfers to property, plant and equipment	–	(1,663,851)	–	–	(1,663,851)
Balance, December 31, 2011	4,668,437	–	–	56,861	4,745,298

Disclosure of Outstanding Share Data (as at April 30, 2012)

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, 55% of the escrowed common shares have been released and an additional 15% will be released on each of May 6, 2012, November 6, 2012 and May 6, 2013.

24,541,106 common shares are subject to escrow agreements, under which, 30% of the escrowed common shares have been released and 15% will be released on each of 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	29,925,000	August 31, 2012

On March 23, 3012, the expiry date of the warrants was extended from April 23, 2012 to August 31, 2012. In the event that the Company's common shares trade at or above C$0.80 for more than 20 consecutive days, the 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	Expiry date	Number of options
C$0.15	July 28, 2012	1,000,000
C$0.15	May 12, 2015	6,350,000
C$0.15	July 20, 2015	1,000,000
C$0.15	August 31, 2015	425,000
C$0.15	January 18, 2016	650,000
C$0.15	May 5, 2016	600,000
C$0.15	September 19, 2016	350,000
		10,375,000

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.