Enhanced Oil Resources Inc.

Management's Discussion & Analysis

Three months ended March 31, 2010

Enhanced Oil Resources Inc.
Management Discussion & Analysis for the Three Months Ended March 31, 2010

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Management's Discussion and Analysis and in certain documents incorporated by reference into this Management's Discussion and Analysis, contain estimates and assumptions which management is required to make regarding future events and may constitute forward-looking statements within the meaning of applicable securities laws. Management's assessment of future plans, operations, drilling and development plans and timing thereof, other capital expenditures and timing thereof, methods of financing capital expenditures and the ability to fund financial liabilities, expected commodity prices and the impact on the Company, and the timing of and impact of adoption of IFRS and other accounting policies may constitute forward looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, the flexibility of capital funding plans and the source of funding therefore; production, marketing and transportation, loss of markets, volatility of commodity prices, the effect of the Company's risk management program, including the impact of derivative financial instruments; currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, the inability to fully realize the benefits of the acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources.
All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar other expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Management's Discussion and Analysis should not be unduly relied upon. These statements speak only as of the date of this Management's Discussion and Analysis, as the case may be. The Company does not intend, and does not assume an obligation, to update these forward-looking statements, except as required by securities law.

In particular, this Management's Discussion and Analysis and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- *the quantity of reserve and contingent resources;*
- *crude oil, natural gas, CO_2 and helium production levels;*
- *capital expenditure programs;*
- *projections of market prices and costs;*
- *supply and demand for crude oil , natural gas, CO_2 and helium;*
- *expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development; and*
- *treatment under government regulatory and taxation regimes.*

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis:

- *volatility in market prices for oil and natural gas;*
- *liabilities and risks inherent in oil and natural gas operations;*
- *uncertainties associated with estimating reserves;*
- *competition for, among other things, capital, acquisitions of reserves, undeveloped lands and*
- *skilled personnel;*
- *incorrect assessments of the value of acquisitions; and*
- *geological, technical, drilling and processing problems.*

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
BBls/d	barrels per day
BOPD	barrels of oil per day
MMbbls	million barrels
Mbbls	thousand barrels

Carbon Dioxide and Natural Gas

Bcf	billion cubic feet
CO_2	carbon dioxide
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Tcf	trillion cubic feet

API	American Petroleum Institute
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of one boe for six mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
Contingent resource	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.
DOE	United States Department of Energy
EBITDA	Income before income taxes, depletion, depreciation, amortization and accretion
EOR	Enhanced oil recovery, typically any method of economically removing oil incremental to that produced by primary or conventional improved-recovery methods
MBOE	1,000 barrels of oil equivalent
Net revenue	Gross revenue less all taxes, royalties and lease operating expenses
NI 51-101	National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators
OOIP	Original oil in place

Primary recovery	Production in which only existing natural energy sources in the reservoir provide for movement of well fluids.
Permian Basin	A large crude oil and natural gas producing area representing a sedimentary basin dating from the Permian geologic period and covering an area extending from West Texas to eastern New Mexico
Reserves	Estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward based on (i) analysis of drilling, geophysical and engineering data; (ii) the use of established technology; (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and (iv) a remaining reserve life of 50 years. These definitions and disclosures are in accordance with the definitions, procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook and the Canadian Securities Administrators NI 51-101.
Secondary recovery	Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from external sources) into the formation, thereby effecting a restoration of reservoir energy which moves the unrecoverable secondary reserves through the reservoir to the wellbore.
Tertiary recovery	any of various methods, chiefly reservoir drive mechanisms and enhanced recover techniques, designed to improve the flow of hydrocarbons from the reservoir to the wellbore to recover more oil after the primary and secondary methods (water and gas floods) are uneconomic.
US $	United States dollars

The Company

Enhanced Oil Resources Inc. ("we", "our" or "the Company") is a natural resource company incorporated in 1980 and is currently engaged in the acquisition, exploration, exploitation, and development of natural resource properties in the Southwestern United States. In June 2007, the Company changed its name to Enhanced Oil Resources Inc. and its stock trading symbol to "EOR" to reflect a change in the Company's added focus on the development of enhanced recovery activities, principally, techniques of CO_2 injection used to increase an oil field's ultimate oil recovery and extend an oil field's productive life. The Company's headquarters is in Houston, Texas. Common shares of the Company are listed and posted for trading on the TSX Venture Exchange ("TSX-V") under the symbol "EOR". The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2009 as well as the MD&A for the same period. This MD&A is effective May 21, 2010. Additional information relating to the Company can be found on the SEDAR website at www.sedar.com.

Executive Summary For The First Quarter 2010

Results of operations for the first quarter of 2010 were revenues of $2.9 million, (a 383% increase) and a net loss of $0.3 million (an 84% decrease) compared to revenues of $0.6 million and net loss of $2.1 million in first quarter 2009. These results continued a turn-around trend begun in late 2009 of increased oil production, improving oil prices, lower operating costs and increasing cash flows. These improved results reflected the continuing development of our oil reserves and the resulting effect of increased oil production. Our 2010 first quarter production of 47,274 gross oil equivalent barrels (or "Boe's") exceeded the 17,841 gross Boe's produced in the first quarter of 2009, an increase of 165% in production. Cash flows from operations for the first quarter were $1.1 million, the second consecutive quarter of positive operating cash flows in the Company's history. Improving oil prices also contributed to the Company's increased revenue, with the Company's oil production averaging US $75.17 per Boe in 2010 compared to US $34.82 per Boe for the first quarter of 2009. Our first quarter 2010 netback per Boe of US$ 35.08 represented a decrease compared to US$43.01 per Boe achieved in the fourth quarter of 2009 due to higher lease operating expenses and certain lease and well restoration costs we had planned for 2010. This is compared to a netback of US$8.59 per Boe for the first quarter of 2009. Our per Boe lifting costs increased to US $19.97 per Boe in the first quarter of 2010 (US$15.34 per Boe for the first quarter of 2009) principally as a result of increased water disposal costs and increased workover costs**.**

We are continuing to focus on the development of our crude oil properties which offer the most immediate cash flow opportunities to add proved reserves. We believe attainment of increasing our performance of these objectives should translate into improving our stock price and enabling us to develop our significant resource properties. The value we can create from our oil properties will provide the platform for investment capital required to ultimately develop the St Johns Helium and CO_2 field. Specifically in the first quarter 2010, we increased our first quarter oil production by over 41%, averaging 519 BOPD compared to 369 BOPD in the fourth quarter of 2009 and compared to 194 BOPD averaged in the first quarter of 2009 This increase resulted from two reactivations in the Crossroads field we completed in the first quarter of 2010.

We have continued to select our major projects on the basis of their cash requirements and choosing those which provide the most immediate cash flow returns. To this end, we recently announced a five year contract for the purchase and delivery of CO_2 from Kinder Morgan CO_2 Company LLP as an interim step to initiate a full field CO_2 flood within our Milnesand Unit field in Roosevelt County, New Mexico. We recently announced the addition of 8.0 million gross barrels of undeveloped reserves (proved, probable and possible) recoverable through CO_2 injection in the Milnesand Unit field with a 74.0% net revenue interest and net discounted future net cash flows of $87.9 million (PV10). Since the connection point to this CO_2 source is within 25 miles of our current oil fields, this contract allows us to initiate significant production increases earlier than our other alternatives and to increase proved developed reserves by a multiple of our current 1.0 million gross proved developed reserves. Since the financing for this project is more heavily weighted toward actual field development costs as opposed to a much longer distance pipeline cost and financing for our own CO_2 at St Johns field, the opportunity to create value in our oil reserves using an interim supply source of CO_2 is compelling. We are evaluating the pipeline right-of-way issues and our financing requirements for this project and aggressively pursuing financing for the development of these CO_2 recoverable reserves. In addition, we are currently evaluating infill spacing opportunities to add primary and secondary reserves in our San Andres fields, which would require initial development financing; however, in the long term it would eventually generate the cash flow to finance their continued development. Currently, we estimate there may be 70 infill well locations at Milnesand, where currently there are no attributed reserves. Development of these locations offers more immediate cash flow potential for investment.

As we have stated above, cash flow and proved oil reserve additions are our immediate focus in 2010 and our assumption and decisions are based on the major factors that will drive our business segments going forward. These include: oil reserves, oil price, oil production, lifting costs, operating personnel, cost of capital, and property acquisitions and property dispositions. Our performance indicators that will measure the attainment of the Company's objectives are: operating cash flow, capital requirements, and access to capital.

Business Segments. We have two reportable business segments with all activities located in the United States:

- **Crude oil and natural gas production segment** – the Company produces oil and gas from three Permian Basin crude oil fields located in eastern New Mexico. The fields were purchased in 2007 (Chaveroo Field and Milnesand Unit) and 2008 (Crossroads Unit) because they represent excellent candidates for enhanced oil recovery through CO_2 injection (See **Acquisitions of Enhanced Oil Recovery Capable Properties)** based on estimates of substantial remaining original-oil-in-place ("OOIP"). In the first quarter of 2010, production from these fields averaged approximately 519 barrels of oil per day (Bbl/d), currently with no proved developed producing reserves attributable to CO_2 recovery. The OOIP associated with these fields represents more than 300 million barrels, of which as much as 20% of OOIP could be recoverable through enhanced recovery methods by CO_2 injection. The Milnesand Unit CO_2 Pilot project ("MSU Pilot") was the Company's first CO_2 pilot project and was commenced in March 2008, with CO_2 injection initiated in August 2008. The MSU Pilot has demonstrated sufficient results to justify a full CO_2 development flood project with 3P reserves estimated at approximately 8.0 million gross barrels of crude oil at December 31, 2009 (See **Strategy for Enhanced Recovery Projects in Crude Oil Fields** below).

- **Helium and CO_2 resource segment** – the exploration for and production of helium and carbon dioxide (CO_2) within the St. Johns field ("St. Johns Field"), a 250,174 acre resource property in Arizona/New Mexico discovered by the Company in 1994. The field is one of the largest known undeveloped helium and natural CO_2 resources in the world, with approximately 62 Bcf of helium and 15 Tcf of CO_2 gas in place (See **Resource Estimates** below). The field is in the early stage of development, pending the construction of a liquid Helium extraction plant and a pipeline required to transport CO_2 to the Permian Basin. Development drilling of the field, construction of a gathering system and a helium processing plant would commence after the point that pipeline financing is committed. The Company was not successful in securing a joint venture partner in a Project review process initiated in February 2009 and completed in June 2009 (See "**Development of the St Johns Field**" below). Subsequently, the Company completed the unitization of the Arizona portion of the field in 2009 with the approval of the St John Gas Unit by the Arizona State Land Department and is evaluating alternatives to the joint venture approach for the development and use of this segment. (See "**Further Development of St Johns Field"** and "Impairment of Property and Equipment" below).

Business Strategy

We are a resource company that is currently focused on developing crude oil reserves from three existing oil fields in the Permian Basin through enhanced recovery techniques utilizing CO_2 injection and making acquisitions of other oil fields suitable for enhanced oil recovery. Our goal is to establish EOR among the 10 largest oil producers in the Permian Basin of New Mexico within five years. We have access to sources of CO_2 through a third party CO_2 gas contract and we own a 100% interest in the largest undeveloped Helium and CO_2 Unit in North America, the St. Johns Field. We have spent many years establishing the reserves potential of our helium and CO_2 field and are now engaged in increasing the crude oil reserves in our three oil fields by preparing those fields for CO_2 injection. Independent engineering consultants have estimated that our oil fields could potentially recover amounts up to 50 to 60 million gross barrels of crude oil.

In today's economic environment we believe the best way to create long-term shareholder value is to increase operating cash flows from oil production sustainable from long life properties. Accordingly, we have concentrated on the acquisition of long productive life assets suitable for CO_2 injection to match the long life reserves that our St Johns Helium and CO_2 field possesses. In addition, we believe that, ultimately, to increase oil production from legacy oilfields in New Mexico, an additional large source of CO_2 is required in the Permian Basin and that the St Johns field can fill that need. We believe that by accelerating production at our oilfields through a third party gas contract, we will be able to generate value for the St Johns field development. The capital requirements at St Johns are extensive and will require the Company to grow its oil and gas operations base before significant joint venture funding of the helium and CO_2 segment can be achieved. To this end in 2009, we completed the evaluation of our Milnesand Unit Pilot CO_2 project that resulted in the addition of significant proved, probable and possible reserves of approximately US $88 million (PV10), and with ongoing development activities in the Crossroads Unit, we have increased our developed reserves to US $30.1 million (PV10). In addition, we believe that the Chaveroo Field, which is more than four times the footprint of the Milnesand Unit, holds at least the same or more potential as Milnesand for potentially CO_2 recoverable oil reserves. With these fields we believe we can increase shareholder value by growing our resource asset base into a proved oil reserves base that will ultimately generate and attract the investment required to deliver St. Johns CO_2 to the Permian Basin.

The economic environment in late 2008 and for most of 2009 served to increase the uncertainties affecting business strategies generally, and with a continuing recessionary environment, commodity prices will continue to be unpredictable. Volatile credit markets will continue to affect our access to capital. These uncertainties have affected our ability to meet our long-term objectives in the St Johns field, primarily because of our reliance on significant equity capital in the absence of profitable operations. Without sufficient capital the success of our business plan will be difficult to achieve since both our business segments depend principally on commodity price thresholds and acceptable returns on investment that are sustainable over long-term periods in order to justify the capital investment that these projects demand. We will continue to face competing petroleum investments whose capital requirements may enjoy lower operating cost structures and higher financial rates of return. With the contraction in the credit and equity markets, success in our helium and CO_2 segment is now more dependent on coupling this resource with a smaller pipeline to our own enhanced oil recovery projects by including the cash flows from our crude oil production, and by limiting the use of CO_2 to a smaller group of producers located nearer to our existing oil properties. Establishing an alternative economic pipeline justification in this approach will entail an additional pipeline path and cost analysis which will continue to be evaluated in 2010. In addition, the Company will pursue financing for the development of its oil properties including the costs of infill drilling and secondary recovery water floods which are a necessary element of enhanced oil recovery ('EOR") preceding CO_2 injection. The Company's projects are inherently long-term, and management will continue to take a long-term view as it considers, among other criteria, current and expected economic and operating alternatives.

Crude Oil and Natural Gas Production Segment - History and Business

The Company entered this business segment through the purchase of two oil fields located in the Permian Basin in 2007. In September 2007, the Company opened an operations office in Midland Texas, operating under the name of EOR Operating Company and focused on establishing enhanced oil recovery projects on the newly purchased fields. See further discussion below under "***Acquisitions of Enhanced Oil Recovery Capable Properties***". In connection with one of our acquisitions, we were successful in 2009 in identifying additional primary production, which resulted in a 295% increase in gross proved developed crude oil reserves (See "***Strategy for Enhanced Recovery Projects in Crude Oil Field – Crossroads Unit Field Operations***" *below).*

Acquisitions of Enhanced Oil Recovery Capable Properties

In February and May 2007, we announced the acquisition of two New Mexico oil fields, the Chaveroo field and the Milnesand Unit field, that the US Department of Energy ("DOE") has identified as having considerable enhanced oil recovery ("EOR") potential. These acquisitions cover approximately 21,000 acres and have produced approximately 36 million barrels of oil to date, leading to only 14% recovery of the estimated original 275 million barrels of original oil in place. In June 2008 the Company completed the acquisition of its third property in the Permian Basin suitable for tertiary recovery by CO_2 injection for $4.5 million. This Crossroads Unit has produced approximately 22 million barrels of crude oil to date, yielding a 35% recovery of an estimated 65 million barrels of original oil in place. In addition, this latest acquisition is located proximal to our original acquisitions and will allow for synergies and cost savings once we begin to CO_2 flood these fields.

Effective July 1, 2008, the Company purchased a 100% working interest in a 1,900 acre New Mexico oil field for US $436,000. The property is contiguous to our existing Milnesand San Andres Unit and is a logical property expansion. Resource estimates of this property have been that it contains approximately 24 million barrels of original oil in place, only 10% of which is estimated to have been produced to date. The acquisition closed in October 2008. The Company capitalized the estimated asset retirement obligation of US $230,000 at the effective date based on the discounted estimated cash flows to retire and abandon the property.

As discussed above, our acquisitions targeted oilfields that the DOE has identified as having considerable EOR potential. These acquisitions cover approximately 23,900 acres and have produced approximately 58 million barrels of oil to date, leading to only 17% recovery of the estimated original 350 million barrels of original oil in place. The Company's independent enhanced recovery consultants, Advanced Resources International ("ARI"), completed a proprietary review of these fields for the Company and, in reports dated January 3, 2007, March 19, 2007, and April 7, 2008, have estimated that these fields could recover an additional 75 million barrels of oil using state of the art CO_2 injection processes. These estimates are categorized as "contingent resources" under NI 51-101 until the properties are evaluated, typically through pilot injection projects, to test potential recoveries and estimate reserves. ARI also estimates that these fields have the potential, once fully flooded, to reach enhanced recovery peak production rates of over 23,000 barrels of oil per day. In 2008, we initiated the MSU Pilot, a pilot CO_2 flood on a portion of the Milnesand Unit, acquired in 2007. The Company commenced injection of CO_2 in August 2008 following a six month water injection program and continued CO_2 injection until the end of July 2009. Water injection is continuing in the MSU Pilot. The incremental production response from the pilot was evaluated for estimates of production that might be recoverable, from a full-field water flood and CO_2 flood. Under NI 51-101 "contingent resources" are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but is currently not economic. At December 31, 2009 as a result of the MSU Pilot's performance, we were able to establish this field, initially classified as a contingent resource, with total proved, probable and possible gross reserves of 8.0 million barrels.

Strategy for Enhanced Recovery Projects in Crude Oil Fields

Long-term, the Company holds its three crude oil fields pending the establishment of full field CO_2 floods sometime in the future, which will depend ultimately on the price of crude oil and the operating and capital costs required to produce these enhanced recovery projects economically. Management expects these projects will not commence until a source of CO_2 is acquired for these fields.

The Company's current oil field asset base has the potential to increase oil reserves from our existing proved developed reserves of 1.0 million gross barrels oil recoverable to reserves in excess of 50 million gross barrels oil recoverable through infill development drilling, secondary and tertiary oil recovery. Current production, which averaged 519 BOPD through the first quarter of 2010, could be increased to over 8,000 BOPD in these fields by continuing the redevelopment of these assets. Growth in reserves and production will occur over time with projects tailored to the condition and opportunities each field presents:

- In the first phase – exploitation activities will concentrate on drilling infill spacing opportunities and fracture stimulation of the San Andres reservoir at Milnesand and Chaveroo fields, which would then be followed by CO_2 flooding via an existing CO_2 supply contract.
- Subsequent phases – exploitation through the implementation of full field CO_2 flooding at these and other fields from the Company's St. Johns Field or through alternate gas contracts.

Kinder Morgan Contract. In April 2010, the Company executed a cancellable five year CO_2 purchase and delivery agreement with Kinder Morgan CO_2 Company, L.P. (Kinder Morgan) for the purchase of CO_2 by the Company in its tertiary oil projects in the Permian Basin. The contract with Kinder Morgan is a take or pay commitment for a total of 27.4 bcf of CO_2 to be purchased by the Company over a 5 year period commencing no later than August 31, 2012. The maximum daily rate to be purchased under the contract is 20 million cubic feet per day during year three. The purchase commitment is cancellable on or before February 28, 2011 with the payment of a termination fee. The Company secured the commitment by posting a letter of credit in the amount of US $1.0 million. The cost of CO_2 will fluctuate based on the price of oil and transportation tariffs.. Proved plus Probable plus Possible (3P) reserves were estimated at 105,280 gross barrels per producer, or 8.0 MMBO to the Phase 1 area. Cawley Gillespie has also estimated that the future net cash flows available to the Company's interest at Milnesand is estimated at US$222.5 million, net of capital costs and including the operating cost of purchased CO_2. The Company is evaluating the cost and alternative rights-of-way for construction of a pipeline from the Cortez CO_2 pipeline take point, approximately 25 miles from the Milnesand field. The execution of this agreement with Kinder Morgan is a critical part of our overall business plan and will accelerate the development of our EOR asset base.

The Phase 1 Milnesand CO_2 flood development (see above) will incorporate 3,000 acres within the central part of the 6,000 acre Milnesand field and has been modeled to include up to 64 injectors and 89 producers. Peak oil production from this phase 1 development model, at the 2P level, is estimated to reach 2,200 BOPD within 3 years after initiating CO_2 injection. As discussed above, prior to initiating CO_2 injection, a drilling program is expected to be commenced to reduce the current 40 acre well spacing down to 20 acre spacing and, potentially over time, to 10 acre spacing. The infill drilling program is expected to increase primary recovery, increase daily production and provide a better conduit between producers and injectors.

The Company's Milnesand CO_2 pilot results confirmed expectations that considerable value can be generated at Milnesand and by analogy, for some portion of our adjacent 21,000 acre Chaveroo field by the use of CO_2 flooding. The Kinder Morgan contract enables the Company to accelerate the development of these assets while we further develop the Company's St. Johns Helium and CO_2 field in Arizona and New Mexico.

Chaveroo Field Operations Status. The Company intends to consolidate its ownership of the Chaveroo field through further unitization of the unconsolidated property interests and produce the field on a limited basis as economics permit to preserve the non-productive acreage. The Chaveroo field, which is comprised of approximately 264 wells within multiple unconsolidated operating units and other discrete operating leases, has approximately 36 wells currently capable of producing. All of the wells capable of production in this field may not be uniformly economic depending upon the field posted price for New Mexico sour crude. Leases in the Chaveroo field are held by a combination of producing certain wells, payment of delay rentals or reactivation of non-producing wells, the costs of which may or may not prove to be economic under this current operating strategy.

Milnesand Unit Field Operations Status. The Company's Milnesand Unit is comprised of 92 wells, of which 47 are currently capable of production. The Company initiated a pilot CO_2 project in March 2008 whereby wells were reworked, water injection was initiated and CO_2 was injected for approximately 12 months, Although certain wells in the field may not be economic at the current pricing for New Mexico sour crude, the Company's operation of the MSU Pilot CO_2 injection project within a portion of these producing wells results in a much higher operating cost than might be otherwise justified to continue to produce. Since inception of this pilot in March 2008, the Company has capitalized the incremental project costs in excess of lifting costs of the MSU Pilot under full cost accounting principles as major development project costs, pending the final results of the pilot. The Company commenced CO_2

injection in August 2008 and completed the final stages of CO_2 injection in early August 2009 and thereby discontinued the injection of CO_2. The Company is continuing water injection on the MSU Pilot, which is normal to CO_2 injection projects to allow the injected CO_2 to continue migration through the producing formation. Based on the results of the MSU Pilot to date, Cawley Gillespie and Associates, the Company's independent engineering firm, has estimated that gross undeveloped reserves of 8.0 million barrels (proved, probable and possible reserves), can be attributed to a 3,000 acre wide comprehensive CO_2 flood. Based on the Company's net revenue interest of 74% in the acreage identified for the flood, the discounted future net cash flows attributed to the Company's interest is estimated at $87.9 million (PV10). As discussed above, the capital and financing requirements are pending facility and pipeline planning, which is required prior to construction.

Currently, the Company produces the above two fields managing the combined objectives of (i) optimizing net cash flow or out flow (ii) maintenance and retention of multiple lease positions through production, however limited, and (iii) consolidating and controlling these property interests for their long-term potential through enhanced recovery techniques. For the first quarter of 2010, lifting costs for these two fields (excluding severance taxes) was US$(94.34) per gross Boe compared to an average of approximately US $27.60 per Boe and US $42.57 per Boe averaged for all of 2009 and 2008, respectively. However, because of the age of these fields, we expect restorative and maintenance costs in these fields to be higher in future periods because of regulatory requirements until we are able to commence EOR projects in these fields. We have budgeted $1.0 million for 2010 for such costs in both fields which would increase our total lease operating expense by at least $6.00 per Boe for the year.

Crossroads Unit Field Operations Status. The third New Mexico field, the Crossroads (Siluro Devonian) Unit, which comprised approximately 85% of our current production in 2010 (65% of our gross oil production in 2009), is economic at current prices. We re-entered and/or re-activated 2 wells during the first quarter of 2010 and 4 wells in 2009. Through these continued operating enhancement activities in the field we have increased proved developed discounted future net cash flows to US$29.7 million from US$3.1 million and increased average daily production from less than 80 BOPD averaged in 2008 to 438 BOPD averaged for the first quarter of 2010. Lifting costs at Crossroads was approximately US $ 7.01 for the first quarter of 2010 compared to US$ 6.60 per Boe for first quarter 2009, which reflects increasing water disposal costs, which began in February 2010 due to capacity limits with regard to the one salt water disposal well in the field. Workover costs of approximately US$500,000 will be required in the second quarter of 2010 to upgrade this well in order to handle the increased fluid volumes in the field. Additional costs, including the reactivation of an additional salt water disposal well will be required to handle additional well reactivations in the field. As a result, per unit lifting costs for this field will likely increase near-term and reduce overall operating cash flow until we complete these repairs and betterments associated with this field's water disposal facilities.

Revenue and Costs Available to Cover Expenses and Capital Outlays. The combined contribution of net revenue available from these three properties that is available to cover other costs and expenses is currently projected for 2010 (at current prices and current production levels) of approximately US $1.4 million net revenue per quarter, net to the Company's interest, before general & administrative expenses and any capital outlays. Capital expenditures for the oil and gas segment in first quarter 2010 were approximately US$0.5 million. Capital expenditures for these fields for 2010 are tied to cash flows on quarter-to-quarter authorizations and are currently projected at approximately US $2.5 million, not including estimates of US $1.0 million allocated to additional lease operating expenses for restorative and regulatory mandated maintenance for all fields. In the first quarter of 2010, these costs were US$365,000 compared to US$19,000 for the first quarter of 2009. Estimates for these costs are included in the above estimated net revenue available quarterly and will have the effect of increasing our per unit lifting costs for all fields.

Capitalized costs related to proved reserves are subject to periodic ceiling tests in connection with the full-cost method of accounting for oil and gas properties (See "***Future Changes in Accounting Policies –International Financial Reporting Standards")***. The Company periodically evaluates the recoverability of the capitalized costs associated with unevaluated oil and gas interests related to all its fields based on both internal and third party studies and evaluations of estimates of potential recovery of its prospective interests. Currently the Company has total capitalized costs associated with the oil and gas assets of net US $27.8 million (aggregate of proved and unevaluated costs) compared to discounted future net revenue from proved developed oil and gas properties of US $30.1 million.

Development of the St Johns Field

As a result of the current market conditions and tight liquidity markets, we have changed our approach to the development of the St Johns Helium and CO_2 field after unsuccessfully attempting to secure a joint venture partner for the pipeline and development project design we identified and engineered in 2008. We engaged investment bankers in February 2009 to review the project design with qualified third parties that would jointly finance and develop the St. Johns field to the extent required to deliver a CO_2 pipeline capacity of 500 MMCFPD. This process was concluded in June 2009 with no formal expressions of joint venture interest. We now position this project primarily for our own use of CO_2 in our Permian Basin oil fields scaled primarily to the smaller size of our CO_2 needs as we subsequently identify them. Currently, we do not expect that we can finance and complete a pipeline from St Johns to our oil fields until 2014. Accordingly, we have secured an interim source of CO_2 to inject into our fields with deliveries beginning no later than August 31, 2012.

History of our recent development of St Johns field. In 2007 and 2008, the Company raised and committed substantial resources for the exploration of the St. Johns field to evaluate its potential to produce helium and CO_2 in quantities sufficient to justify the cost of delivery to consumers of the products. In 2008, the Company completed sufficient exploration to broadly define the characteristics of the field that enabled third party engineering firms to provide estimates of the field's reserves and estimates of field deliverability rates of CO_2 to allow the Company or its representatives to solicit long-term commitments from potential consumers. In addition, the Company engaged Suncoast Energy, Inc. ("Suncoast"), a pipeline expert, to develop the scope and path of a pipeline and to secure financing of a pipeline suitable for the CO_2 market in the Permian Basin. Working together with third party engineering firms to design and estimate the costs to construct the gathering and processing systems for the field and with its knowledgeable pipeline experts, a project design and pipeline design was conceived and proposed in the summer of 2008. However, in connection with the changes in economic conditions in late 2008, it became apparent that the Company could not continue to develop the St Johns field solely from its own capital sources. After the credit market collapse following September 2008, financing a development project of the size and scope of the projected investment in St. Johns field, as well as on financing the third party pipeline, became more difficult for a company with limited resources. In October 2008, Suncoast advised the Company that they could not secure pipeline financing for the proved CO_2 reserves at St Johns. It became clear that increased cost of capital requirements now prevail for such projects and the uncertainty of energy prices will affect rate of return requirements for prospective investments.

We remain committed to the view that the potential use of this asset is ultimately valuable to the oil industry, including ourselves, as well as other potential uses. However, ultimately realizing value on the asset will continue to require that the Company finance the holding costs over a long-term period until pipeline financing is secured and a pipeline is constructed. We believe we have reduced such future holding costs in the short-term, absent any required drilling, to allow the Company to continue to develop alternatives to the project design concluded in 2008.

Management is reviewing the feasibility of a smaller pipeline that would reduce the capital costs to deliver a smaller volume of CO_2 for use in its own oil fields in Roosevelt, Chaves and Lea counties in New Mexico and possibly to a smaller group of potential CO_2 users in close proximity to these properties. The smaller project would couple the oil field interests with the Helium/CO_2 resource to combine investments that would be supported by the recovery of crude oil with a view of increasing rate of return, lowering capital costs and the lowering cost of capital through a comprehensive investment.

Current Operating Activities

From an operating standpoint, the activities planned in 2010 for the operating and project phases are focused principally in the oil field segment on activities that can generate additional free cash flow and generate reserve growth. We have begun to establish a producing base of assets that will partially finance opportunities within our existing fields, cover overhead and facilitate the maintenance of the St. John's Field. In addition, we have focused our operating activities to increasing cash flows from our oil and gas producing properties, including well re-activations and workovers that increase production and reduce our lifting costs. In addition, we continue to focus on reducing short-term cash requirements through unitization of property interests in both of our business segments and from certain equipment held for sale. In our oil field segment, until our recent increase in production, we were reluctant to hedge our commodity prices due to our small production volumes, however, we are currently evaluating the current economics of such contracts in connection with development financing for both our Crossroads Field and Milnesand field development activities. Since a history of generating quarterly positive cash flow from operations will be a key to securing long-term development financing for larger projects, we have utilized our available cash, increased receipts from crude oil sales and utilized vendor credit in the reactivation of certain oil and gas wells and workovers. The Crossroads field produced approximately 40,300 gross barrels for the first quarter of 2010 compared to 8,000 gross barrels for the first quarter of 2009 (62,700 gross barrels for the year ended December 31, 2009). In addition to increased daily production, our recent well reactivations and workovers at Crossroads Unit has resulted in increasing our total net proved developed reserves as of December 31, 2009 to 814,000 net barrels (approximately 1.025 million gross barrels) compared to 148,000 net barrels at December 31, 2008. The estimated future net discounted cash flows attributable to total proved developed reserves at December 31, 2009 was approximately $30.1 million, net to the Company's interest, based on forecast pricing as of December 31, 2009 and a discount rate of 10%.

Management has principally focused the Company's activities on (i) specific development plans designed to increase oil production and reserves of its crude oil properties in New Mexico and (ii) efforts to establish an alternative development plan and supporting economics for the St. Johns Gas Unit field focusing initially on CO_2 delivery to our own enhanced oil recovery projects. Currently, specific activities this year include:

- Increasing cash flow from our oil field properties through in-fill development, increased operating efficiencies, reducing costs, attempting well reactivations and workovers, and pursuing additional oil field acquisitions consistent with our EOR business,

- Continuing to focus on immediate cash flow enhancement in operations and the longer term objectives for our existing oil field properties,
- Commencing the plans and financing the full-field CO_2 flood at Milnesand,
- Securing additional joint venture participants who own miscible CO_2 flood opportunities that desire a source of CO_2,
- Combining oil field interests with other Permian basin producers in arrangements to secure pipeline financing and CO_2 delivery by combining oil field ventures to improve project returns, and
- Establishing an alternative pipeline economic justification to finance a more direct delivery of CO_2 from the St Johns Gas Unit to our crude oil properties.

While the continuing impact of global economic and financial circumstances may restrict our access to capital markets and create significant volatility in equity valuations, management believes its projects have the scope and potential that will justify long-term investment by consumers and producers of the resource interests we have assembled. The fundamentals of our St. Johns project will continue to be tailored to changing conditions of markets and competing transactions. Our St Johns helium and CO_2 field requires a long-life resource perspective and is complemented by the long-term productive potential for producing crude oil from our oil fields as well as other technology opportunities to monetize the CO_2 resource.

Helium and CO_2 Resource Segment – History and Business

In its history, the Company has explored for precious metals, diamonds and crude oil and natural gas in North America. In 1994, the Company discovered helium and carbon dioxide ("CO_2") while drilling for crude oil and natural gas on what later developed as the St. Johns Field located in eastern Arizona and western New Mexico. The Company currently owns a 100% working interest in leases covering approximately 251,000 gross acres and continuously manages its lease position to optimize its land position within St. Johns Field. From 1994 through 2006, the Company had been engaged principally in the business of exploration and appraisal of the St. Johns Field. Through December 31, 2009, we have expended approximately $100.4 million in acquiring, exploring and appraising the St. Johns Field, with over $33.4 million invested in the appraisal of the field. Prior to 2007, the Company had drilled seventeen exploratory and delineation wells. Prior activities had focused on periodic drilling to maintain its lease position, with production testing, well data evaluation, feasibility studies and resource evaluations limited by available capital. Though constrained, the results of these activities enhanced the view that the St. Johns Field contains significant gas in place.

During 2007, the Company began to grow its infrastructure necessary to support the extensive tasks required for the financing and development requirements of the St. Johns Field that had constituted its sole asset for over ten years, but with little movement towards its development to that point. In 2007 and 2008, increasing crude oil prices allowed us to present the St. Johns Field as an attractive investment alternative through a strategy that would source CO_2 from our own property for use in our own EOR projects in order to establish a potentially significant crude oil reserves base. This exploitation strategy made economic sense in 2007 and allowed us to raise the equity to fund additional evaluation projects needed for our helium and CO_2 source field and to purchase EOR properties in the Permian Basin suitable for CO_2 flooding projects. Even considering the fall in crude prices in late 2008, stranded oil in the Permian Basin represents a reasonable bargain compared to other exploration plays due to the recovery potential of OOIP in certain fields and formations as demonstrated by recent production histories of CO_2 floods in the basin. As a result, we began an active acquisition program in 2007 for oilfields with significant OOIP and with characteristics suitable for CO_2 injection. This strategy change was especially important to our success in raising net proceeds from equity offerings of $59.1 million during 2007 and an additional $32.5 million in 2008. In addition, our recent success in our Crossroads field from well re-activations has demonstrated additional primary production potential in this field with immediate impact to our cash flows.

In February 2009, we filed our proposed unitization agreement with the Arizona State Land Board for the unitization of 170,300 acres of State of Arizona leases (the "St. Johns Gas Unit"), of which we own leases representing 136,100 gross acres. The unitization of the property interests will allow the Company to maintain its leasehold position by production or by conducting development operations on any of the leases rather than by each separate lease. In the proposed Unit, assuming all leaseholders elect to participate in the Unit, the Company will hold a minimum working interest of approximately 80 % of the Unit with the balance currently held by the one other leaseholder, Hunt Oil Corporation. The St. Johns Gas Unit Agreement would impose a minimum development plan on the Unit's participants over a five year period and will include a commitment to drill five wells in the 12 months following its approval. In September 2009 after discussion with the Arizona State Land Department, we requested a 12 month extension with regard to the drilling obligations. We have received approval for the St. Johns Gas Unit from the State of Arizona and the approval of the US Bureau of Land Management.

In January 2007, we received all approvals for the formation of the Cottonwood Canyon Unit Agreement in Catron County, New Mexico, part of the St. Johns Field. The Cottonwood Canyon unit covers an area of 89,734 acres. This unit agreement calls for the orderly development of the unit area over a five year period. Ridgeway Arizona Oil Corp, a wholly-owned subsidiary of the Company, is designated as the unit operator and is the only working interest participant in the Unit.

St. Johns Field - Drilling Activity

Decreases in oil prices in late 2008 and the resulting effect on the Company's ability to raise additional capital caused the Company to severely restrict its projects for 2009 and curtail expenditures in order to conserve cash. No drilling activity for the St. Johns Field occurred or was planned for 2009; however, during 2010 we expect to drill 5 development wells required under the St Johns Gas Field Unit obligations. During 2008, we drilled 15 net wells to various stages of completion in the St. Johns Field. This is in addition to the 13 net wells we drilled to various stages of completion during 2007. This drilling program was initiated to provide additional data regarding field-wide reserves and deliverability and at the same time preserve the Company's dominant acreage position in the area. This drilling activity expanded our knowledge of the field significantly, which is crucial to the planning of full-field development. The program allowed us to accumulate additional data including well logs for production and reservoir modeling, assess alternative drilling and completion techniques, gather and evaluate bottom hole pressure data, perform pressure transient analysis and review wellbore design modeling alternatives.

To date, we have drilled and evaluated 47 wells across the St. Johns Field. Individual wells have tested CO_2 at sustained rates as high as 6.5 Mmcf/d. Each well is approximately 2,500 ft deep and is capable of being drilled and completed within one week.

Currently, we do not anticipate additional development drilling in the St. Johns Field, except in connection with St. Johns Gas Unit obligations to complete 5 wells before February 1, 2011, as defined in the St John Gas Unit Agreement. We have completed the planning for these wells which are expected to cost $3.0 million and will require additional financing to complete.

Resource Estimates

The following information has been extracted from, and is attributable to, the Helium and CO_2 Resource Evaluation report on the St. Johns Field addressed to the Company dated as of June 12, 2008, prepared by W.M. Cobb and Associates of Dallas, Texas, an independent firm of professional engineers (the "Cobb Report").

The 2008 Cobb Report, updating a 1999 report from the results of the Company's drilling and flow testing programs in 2007 and 2008, indicates that the St. Johns Field resource is potentially significantly larger than earlier estimates had suggested with potentially recoverable reserves increasing to 8.0 Tcf of CO_2 and 33 Bcf of helium over a 40 year life. With the higher deliverability of in excess of 6.0 Mmcf/d achieved from the most recent wells drilled in 2008, the 20 year production outlook has increased to 6.6 Tcf of CO_2 and 26 Bcf of helium.

	CO_2			Helium		
Case	Reserves In Place (tcf)	20 Year Recoverable (tcf)	40 Year Recoverable (tcf)	Reserves In Place (bcf)	20 Year Recoverable (bcf)	40 Year Recoverable (bcf)
1999 Report	13.9	-	6.0	64.0	-	33.0
2008 Report --Relative Risk:						
Lower Risk	11.3	5.0	6.2	47.0	20.0	26.0
Higher Risk	13.4	5.9	7.4	56.0	24.0	30.0
Highest Risk	15.0	6.6	8.2	62.0	26.0	33.0

Proposed Third Party CO_2 Pipeline – St. Johns Field to the Permian Basin

The Company's current design plan would utilize a third party owned pipeline to deliver CO_2 to the Permian Basin including a call on the product for injection into its own oil fields. Securing a third party owner to finance, construct and operate the pipeline is a significant objective for the Company that may determine the ultimate success of developing the St Johns field. The Company's CO_2 reserves would be committed to the pipeline under a life of reserves dedication agreement at the point financing of the pipeline is committed. Construction of the pipeline would require up to two years. However, estimates of capital and operating costs for this pipeline design are substantially dependent on the price of steel and energy, which would affect the transport tariff for CO_2 to the ultimate users. Since May 2009, the Company has reviewed the 2008 recommendations and assumptions concerning pipeline capacity and the approach to developing its projects. Management currently is reviewing the feasibility of a smaller pipeline that would reduce the capital costs to deliver a smaller volume than the original design capacity for the needs of it oil fields in Roosevelt, Chaves and Lea counties in New Mexico and possibly to a smaller group of potential CO_2 users near to these properties. The view is that a smaller project would couple the oil field interests with the CO_2 resource to propose investments that would be supported by the recovery of crude oil with a view of increasing rate of return, lowering capital costs and the lowering cost of capital through a comprehensive investment.

Liquidity and Capital Resources

At March 31, 2010, we had cash of $1.6 million and working capital of $1.1 million including cash, an increase of $0.3 million in cash and a decrease of $0.3 million in working capital, since December 31, 2009. The capital intensive nature of the Company's activities may create a working capital deficiency position during periods with high levels of capital investment. The Company has relied on equity placements to fund capital investment, and cash flow from its oil production to fund its cash requirements (See "Equity Placements" below). The Company does not currently have credit facilities to finance its projects, however, may seek to establish initial credit facilities based on its proved crude oil reserves to fund activities designed to increase current production. Although crude oil price increases since March 2009 have increased our net revenue from production, the wide swings in oil prices over the past two years and the continuing uncertainties in credit and equity markets may continue to limit our ability to secure additional sources of capital during a critical time of developing our businesses and projects. Currently we are discussing development financing for our projects with several parties and preparing for additional placements of equity similar to those completed in the last three years (discussed above). As oil prices have improved and production increased, we have increased our capital expenditures on a quarter-to-quarter basis. We will continue to operate to preserve cash with capital spending focused on operations activities that, first, further our positive operating cash flow objective and, second, further our strategic objective in establishing an EOR project on one of our oil fields. With regard to our financing objectives, we will continue to seek financing for oil field acquisitions that meet our criteria and seek equity and debt capital for their acquisition and development. Since a history of generating quarterly positive cash flow from operations will be a key to securing long-term development financing for larger projects, we have utilized our available cash, increased receipts from crude oil sales and utilized vendor credit in the reactivation and of certain oil and gas wells and workovers. The resulting increased cash flows should be adequate to finance our existing short term oil and gas operations, however, we will continue to require additional funds and project financing for expansion and full development all of the Company's properties.

Although the current level of general and administrative expense is projected to decrease by 30% for 2010 as compared to 2009, we expect that we will eventually have to increase our operating personnel and associated overhead as we obtain project financing for our larger projects, which may occur later in 2010. Our general and administrative costs, including field offices decreased US $0.5 million (or 28%) for the three months ended March 31, 2010 compared to the three months ended March 31, 2009.

St. Johns Field Capital Budgets for 2010

We are currently committed to drill five wells under the terms of the St Johns Gas Unit Agreement before February 1, 2011. Exclusive of this commitment our capital budget for St Johns Field is US $0.4 million, principally related to the payment of delay rentals. This field is currently non-producing, pending financing and construction of a CO_2 pipeline, additional field development and construction of a helium processing facility. Except for the drilling obligation discussed above, there are no plans for these projects to commence in 2010 unless the third party pipeline financing is committed.

Oil Fields Capital Budget and CO_2 Project Budget for 2010

Our oil field capital budget expenditures planned for 2010 are US$2.5 million and will be focused on developing production enhancement operations where feasible, engineering and regulatory maintenance, including reactivations and field maintenance. In addition, we intend to continue to pursue oil field property acquisitions that provide reserve development potential and additional cash flow to sustain the overhead costs required to maintain the projects we have undertaken.

Equity Placements

The impact on liquidity from the equity placements has been significant in allowing the evaluation of the helium and CO_2 resources in St. Johns Field, as well as the acquisition of prospective EOR assets in eastern New Mexico. Although expenditures are uncommitted, activities in St. Johns Field will continue, although at levels within our current cash flows. We will have to finance our obligation wells required under the terms of the St Johns Gas Unit Agreement negotiated in 2009 with the state of Arizona Land Department. That agreement requires that we drill and complete five additional wells capable of production before February 1, 2011.

Since 2006, we have completed eleven offerings of equity securities raising total gross proceeds of $100.5 million, and $3.2 million on the exercise of warrants, agency options and stock options. In December 2009 a private placement of 4.0 million units of common shares and warrants was completed for net proceeds of $0.8 million. In June 2009, we completed a private placement of 4.3 million common shares and warrants for net proceeds of $1.9 million. In 2008, we completed four equity placements that represented gross proceeds of $35.1 million and was comprised of 28.4 million common shares and 14.2 million warrants whose expiration is two years. In 2007, we completed five equity placements that represented gross proceeds of $62.4 million and was comprised of 54.9 million common shares and 35.9 million warrants whose expiration were from one to two years of their issue date. Of these warrants issued in 2007, all have expired except for 13.7 million that were extended until 2010. Each of the offerings included warrants and/or agency options to acquire additional shares of the Company’s common stock which would result in additional equity funds, should they be exercised prior to their expiration.

The following summarizes the equity placements since 2007:

Issue Date	Number of Units	Issue Price	Gross Proceeds
June 27, 2008	2,438,500	$ 1.24	$ 3,023,740
June 30, 2008	22,975,681	$ 1.24	$ 28,489,844
July 16, 2008	1,655,000	$ 1.24	$ 2,052,200
July 31, 2008	1,290,000	$ 1.24	$ 1,599,600
June 3, 2009	4,333,333	$ 0.45	$ 1,950,000
December 4, 2009	4,052,600	$ 0.25	$ 1,013,150
	36,745,114		$ 38,128,534

i. On June 16, 2009, we announced a non-brokered private placement that closed with the placement of 4,333,333 Units. The units were priced at $0.45 each and consisted of one common Share and one-half of one non-transferable common share purchase warrant. Each whole share purchase warrant entitles the holder to purchase an additional common share at $0.60 and expires on June 3, 2010. Gross proceeds were $2.0 million. The Company incurred offering costs of $0.2 million, thereby realizing net proceeds of $1.8 million. We allocated the fair value of the net proceeds received upon the sale of the units between the underlying common shares and the common share purchase warrants. The common share purchase warrants' fair value was determined to be $0.2 million.

ii. On November 10, 2009, we announced a non-brokered private placement that closed with 4,052,600 units priced at $0.25 each and consisted of one common share and one non-transferable common share purchase warrant. Each whole share purchase warrant entitles the holder to purchase an additional common share at $0.40 and expires on December 4, 2010. Gross proceeds were $1.0 million and the Company incurred offering costs of $0.1 thereby realizing net proceeds of $0.8 million. The Company allocated the fair value of the net proceeds received upon the sale of the units between the underling common shares and the common share purchase warrants. The common share purchase warrants' fair value was determined to be $0.2 million.

The following table depicts those warrants remaining outstanding at May 21, 2010:

Issue Date	Number of Warrants (1)		Exercise Price		Expiration Date
June 28, 2007	1,195,500	(5)	$	1.80	June 30, 2010
July 4, 2007	3,515,371	(5)	$	1.80	June 30, 2010
July 9, 2007	1,426,600	(5)	$	1.80	June 30, 2010
July 23, 2007	6,395,500	(5)	$	1.80	June 30, 2010
July 27, 2007	1,063,000	(5)	$	1.80	June 30, 2010
June 27, 2008	1,219,250	(2)	$	1.80	June 27, 2010
June 30, 2008	11,487,842	(3)	$	1.80	June 3, 2010
July 16, 2008	827,500	(3)	$	1.80	July 16, 2010
July 31, 2008	645,000	(3)	$	1.80	July 31, 2010
June 3, 2009	2,166,666	(4)	$	0.60	June 30, 2010
December 4, 2009	4,052,600	(6)	$	0.40	December 4, 2010
	33,994,829				

(1) The warrant numbers presented represent the number of whole warrants outstanding for each grant.
(2) These Warrants were issued in connection with the Company's brokered private placement announced on June 28, 2007.
(3) These Warrants were issued in connection with the Company's brokered private placement announced on June 3, 2008.
(4) These Warrants were issued in connection with the Company's brokered private placement announced on June 16, 2009.
(5) These warrants were to expire in June and July, 2009, but were extended until June 30, 2010 announced on June 16, 2009.
(6) These Warrants were issued in connection with the Company's non-brokered private placement announced on November 10, 2009

The table below details outstanding agency options as of May 21, 2010:

Issue Date	Number of Agency Options		Exercise Price	Expiration Date
June 27, 2008	170,695	(1)	$ 1.80	June 27, 2010
July 16, 2008	115,850	(1)	$ 1.80	July 16, 2010
July 31, 2008	90,300	(1)	$ 1.80	July 31, 2010
	376,845			

(1) These Agency Options were issued in connection with the Company's brokered private placement which closed on June 27, July 16, and July 31, 2008 and entitle the holder to acquire one Unit for $1.80. Each Unit entitles the holder to one share of Common Stock and a Warrant to purchase 1/2 share of Common Stock for $1.80.

Results of Operations

A factor influencing the Company's results for all periods is the continuing fluctuation of the Canadian dollar relative to the United States dollar. Virtually all of the Company's operating expenses and capital expenditures are paid in United States dollars while all historical equity funding has been denominated in Canadian dollars, the Company's reporting currency. Although the Canadian dollar gradually strengthened over the past three years, it weakened against the US dollar during the first three months of 2009. For the three months ended March 31, 2010, the Company recorded a foreign currency translation loss of $124,000 compared to a gain of $77,000 for the comparable period in 2009.

Summary of Consolidated Statements of Operations

	Three Months ended March 31,	
	2010	**2009**
	Unaudited	***Unaudited***
Revenues		
Oil and gas sales, net of royalties	2,945	603
Interest and other	4	11
	2,949	614
Expenses		
Production costs	1,224	353
Field expenses	334	404
General and administrative	826	1,210
Accretion of asset retirement obligation	98	108
Depreciation and depletion	386	391
Foreign currency translation (gain) loss	124	(77)
Stock-based compensation	294	358
	3,286	2,747
Loss and comprehensive loss for the period	(337)	(2,133)

Quarter Ended March 31, 2010 Compared the Quarter Ended March 31, 2009

The Company incurred a net loss of $0.3 million for the three months ended March 31, 2010 compared to a loss of $2.1 million for the three months ended March 31, 2009. This decrease in net loss is mainly due to increases in oil and gas production due to 6 well reactivations which occurred after the first quarter 2009. The increased production and increased oil prices for the first quarter of 2010 compared to the first quarter of 2009, both served to increase revenue by $2.3 million in 2010. For the same reasons, severance taxes and production costs increased in first quarter 2010 by $0.9 million over the first quarter 2009. Other changes in expenses were a decrease in stock based compensation expense (non-cash) of $0.1 million and a decrease in general and administrative expense of $0.4 million due principally to personnel cutbacks that occurred after first quarter of 2009. Exchange rate differences in US and Canadian dollars caused a foreign currency translation loss of $0.1 million for the quarter compared to a gain in the same period 2009. Cash flow from operating activities for the first quarter of 2010 was $1.1 million, compared to cash used in operating activities for Q1 2009 of $1.4 million, making the first quarter of 2010 the second consecutive quarter of positive operating cash flows in the Company's history. Earnings before interest, income taxes, depreciation, stock-based compensation, depletion and amortization were $0.5 million for each of the fourth quarter of 2009 and first quarter of 2010.

There were significant changes in the components of revenue for the three months ended March 31, 2010 compared to the same period of the prior year including a 165% increase in net oil and gas Boe's sold, and a 115% increase in the average net crude oil price received per Boe. For the three months ended March 31, 2010, oil field production costs and field expenses increased 106% due to increased oil production. As discussed above, the decrease in general and administrative expenses of $0.4 million was principally related to reductions in personnel after the first quarter of 2009. Employee headcount (the total number of Company employees) averaged 25 employees in the first quarter of 2009 and had decreased to an average of 17 for the first quarter of 2010.

Operating Netbacks

(In US Dollars)		Three Months Ended March 31, 2010	2009
Oil & Gas Sales Volumes			
Oil equivalent	*Boe's*	47,274	17,841
Average prices [1]			
Oil equivalent	*$/Boe*	$ 75.17	$ 34.82
Less:			
Royalties, net [3]	*$/Boe*	$ (13.83)	$ (8.04)
Severance taxes	*$/Boe*	$ (6.29)	$ (2.85)
Operating expenses	*$/Boe*	$ (19.97)	$ (15.34)
Operating Netback [2]	*US$/ Boe*	$ 35.08	$ 8.59
Operating Netback by Field			
Crossroads Field		$ 49.82	$ 20.63
Milnesand Unit		$ (16.61)	$ 1.19
Chaveroo Field		$ (74.59)	$ (4.51)

[1] Average prices are after deduction of transportation costs and do not include realized gains and losses on financial instruments since there were none.

[2] Operating netback equals crude oil and natural gas sales less royalties, operating costs and transportation costs calculated on a Boe basis. Operating netback and funds from operations netback do not have a standardized measure prescribed by Canadian Generally Accepted Accounting Principles and therefore may not be comparable with the calculations of similar measures for other companies.

[3] Net of related severance taxes.

Oil and gas segment financial results are significantly influenced by fluctuations in commodity prices, which include price differentials related to the quality of crude oil and transportation charges, and the U.S./Canadian dollar exchange rate. Net oil and gas sales for the quarters ended March 31, 2010 and 2009 were US$2.4 million and $0.5 million, respectively, and reflect a net production increase of 134% in Q1 2010 to 37,706 net Boe’s compared to 13,881 net Boe’s, respectively. Oil prices fluctuated dramatically for the periods reported for March 31, 2010 and 2009, with first quarter prices received averaging US$ 75.16 per Boe compared to US$34.82 per Boe for the first quarter of 2009.

Net production costs increased by $0.9 million for the first quarter 2010 compared to the first quarter of 2009. Net production costs increases associated with workovers in the Chaveroo field (US $0.2 million), the Milnesand Unit field (US $0.1 million) and increased water disposal costs in the Crossroads Unit field ($0.2 million) affected the per unit metrics by increasing from US$15.34 per Boe in the 1st quarter of 2009 to US$19.97 incurred for the 1st quarter of 2010. Higher production rates in the Crossroads Unit field in 2010 contributed the balance of the increase in production costs. The table above summarizes the Operating Netback for the comparable periods in US Dollars in the aggregate and by field for the three months ended March 31, 2010 and 2009. Lease operating expenses in the Crossroads Unit field are substantially lower than the other two fields at approximately US$7.02 per gross Boe for the quarter ended March 31, 2010. Lease operating expense per gross Boe for the Milnesand Unit field and the Chaveroo field were US $69.74 and US$125.37 for the quarter ended March 31, 2010, respectively, compared to US $22.46 and US $22.38 for the quarter ended March 31, 2009, respectively. Significant site maintenance expenses of $0.2 million for the first quarter of 2010 related to several wells and workovers of thirteen wells in the Chaveroo field in first quarter 2010 which affected the per unit cost for the entire field. This field is characterized by very low per well production rates compared to the Company's other fields. The Chaveroo field will continue to be marginally uneconomic and may incur negative netbacks due to the substantial costs of site maintenance and deteriorated well bore conditions until either secondary recovery projects or enhanced recovery projects are initiated. The Company, however, is able to retain the leasehold positions on a Held By Production basis covering approximately 21,000 gross acres by continuing to produce the marginal wells. For both three month periods ended March 31, 2010 and 2009, the Company's netback from the Chaveroo field was US $(74.59) and US $(4.51), respectively.

The Company purchased its oil and gas properties with the intent to conduct tertiary recovery operations in these reservoirs that have already produced significant amounts of oil over many years; however, in accordance with the rules for recording proved reserves associated with enhanced recovery techniques, such as CO_2 injection, proved reserves cannot be recognized until there is a production response to the injected CO_2 or unless the field is analogous to an existing CO_2 flood. During this evaluation period we have capitalized all costs attributable to the fields as CO_2 major development project costs, except lifting costs attributable to production. Commencing with the initiation of the MSU Pilot in March 2008, we have capitalized approximately US$8.8 million related to major development project costs, including the cost of injected CO_2, production facilities, monitoring and measurement equipment and well work for the producing and injection wells in the pilot group, and the costs of enhanced recovery production equipment. These capitalized development costs are being carried in unevaluated major development project costs within our full-cost pool. After confirming a production response to the CO_2 injections (i.e. the production stage), injection costs will be expensed as incurred and any previously deferred project development costs will become subject to depletion upon recognition of proved tertiary reserves. For the first quarter of 2010 and 2009, we capitalized $0.5 million and $0.7 million, respectively for expenditures related to all tertiary recovery projects.

Unless the Company can continue to increase its primary and secondary production, management expects net operating losses will continue during the development stage of the St. Johns Field and prior to the initiation of full field EOR injection floods in its three oil fields and will also be dependent on the crude oil prices received for its production.

Summary of Quarterly Information:

In thousands, except per share amounts:

	2009			
	Fourth	Third	Second	First
Revenues	$ 2,181	$ 1,448	$ 1,032	$ 614
Loss	$ (243)	$ (1,780)	$ (2,001)	$ (2,133)
Loss per common share	$ -	$ (0.01)	$ (0.01)	$ (0.02)
Loss per fully diluted common share	$ -	$ (0.01)	$ (0.01)	$ (0.02)
Net loss	$ (243)	$ (1,831)	$ (2,001)	$ (2,133)
Net loss per common share	$ -	$ (0.01)	$ (0.01)	$ (0.02)
Net loss per fully diluted common share	$ -	$ (0.01)	$ (0.01)	$ (0.02)

	2008			
	Fourth	Third	Second	First
Revenues	$ 715	$ 1,988	$ 1,360	$ 890
Loss	$ (2,020)	$ (2,718)	$ (1,702)	$ (3,690)
Loss per common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)
Loss per fully diluted common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)
Net loss	$ (2,020)	$ (2,718)	$ (1,702)	$ (3,690)
Net loss per common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)
Net loss per fully diluted common share	$ (0.02)	$ (0.02)	$ (0.03)	$ (0.03)

Quarter-to-quarter changes in revenue. Net Sales volumes were 13,881 Boe's, 15,789 Boe's, 19,914 Boe's and 27,036 Boe's for the first, second , third and fourth quarters of 2009, respectively. The average prices received for sales per barrel oil equivalent in 2009 were US$ $34.86, US$54.24, US$63.99, and US$72.10 for the first, second, third and fourth quarters, respectively. Interest income decreased $0.6 million due to the decrease in cash available in 2009 for temporary investment beginning in the second quarter of 2008 and the decrease in interest rates associated with the collapse in banking and world economies after the third quarter of 2008.

Quarter-to-quarter changes in Loss and Net Loss. Quarterly losses were affected principally by:

- the decrease in general and administrative expense of $0.7 million for each of the third and fourth quarters of 2009 compared to the same quarters in 2008 and increased oil sales from production of $1.5 million in the fourth quarter of 2009,

- currency translation losses including a loss of $2.3 million in first quarter of 2008 and translation gains of $2.3 million, $0.3 million, and $1.0 million recorded in second, third and fourth quarters of 2008, all of which were associated with a weakening US dollar compared to the Canadian dollar and currency volatility that has characterized most major currencies during the last two years,
- the decrease in stock based compensation expense for second and third quarters of 2009 of $2.7 million and $0.7 million, respectively, compared to the expense reported for second and third quarters of 2008, was primarily due to the decrease in stock price that occurred subsequent to September 2009, and
- decreases in the comparable 2009 periods related write-downs charged to expense for losses recognized on notes receivable and equipment held for sale of $0.4 million and $0.8 million for the third and fourth quarters of 2008, respectively.

Quarter-to-quarter changes in per share amounts. Quarterly per share amounts in 2009 were affected by the increase in common shares outstanding related to shares issued in connection with private placements and options exercised. Average outstanding shares by quarter were 141.4 million shares, 142.9 million shares 145.6 million shares and 146.8 million shares for the first, second, third and fourth quarters, respectively.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting

As a TSX-Venture issuer, the Company's officers are not required to certify the design and evaluation of operating effectiveness of the Company's disclosure controls and procedures ("DC&P) or its internal controls over financial reporting ("ICFR"). The Company maintains DC&P designed to ensure that information required to be disclosed in reports filed or submitted is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In addition, the Chief Executive Officer and the Chief Financial Officer have designed controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Due to its size, the scope of its current operations and its limited liquidity and capital resources, there are inherent limitations on the Company's ability to design and implement on a cost effective basis the DC&P and ICFR procedures, the effect of which may result in additional risks related to the quality, reliability, transparency and timeliness of its interim filings and other reports. There have been no changes in ICFR during the three months ended March 31, 2010.

Off-Balance Sheet Arrangements

The Company does not have any special purpose entities nor is it party to any arrangements that would be excluded from the balance sheet. The Company anticipates that accounting for its interest the joint venture contemplated with Greenfire Energy will be determined by the control exercised over the joint venture by the parties, subject to final agreement between the parties,

Related Party Transactions

There were no related party transactions for the periods ending March 31, 2010 and 2009, respectively.

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves. The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. If the cost recovery test fails, impairment is calculated using estimates of discounted future net cash flows attributed to proved and probable reserves. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities are determined using estimated costs discounted based on the estimated life of the asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.

In order to recognize stock based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time. The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on the Company's financial statements.

Impairment of Resource Properties

The carrying value of resource properties, including the St. Johns Gas field resource, are subject to impairment based on periodic assessments by management with regard to the sufficiency of estimated future cash flows or estimates of the fair value of the resource compared to the accumulated capitalized costs of the resource properties. Such assessments and conclusions may be affected by, among other things, a decrease in market prices, adverse changes in economic conditions, unfavorable changes in project economics, or the difficulty in establishing an economic gathering system, all of which may be subject to significant uncertainty. The Company has assessed its resource properties as of the most recent balance sheet date and determined that its capitalized costs continue to be recoverable, however, that assessment may change if the Company is not able to either justify and/or finance a pipeline from the resource properties to its oil and gas properties or otherwise secure an economic use for the CO_2 in the field. Impairment is indicated if the carrying amount of the resource property is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the property and equipment is charged to earnings. The assessment of impairment is dependent on estimates of future cash flows, reserves, production rates, prices, future costs and other relevant assumptions.

Asset Retirement Obligations

The Company is required to provide for future removal and restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. The fair value of the liability for the Company's asset retirement obligations is recorded in the period in which it is expected to be incurred, discounted to its present value using the Company's risk-adjusted interest rate and expected inflation rate. The offset to the liability is recorded in the carrying amount of property and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Future Changes in Accounting Policies

Adoption of CICA Handbook Changes. The Company will be required to adopt the following CICA Handbook sections as of January 1, 2011:

(i) The CICA issued Handbook Section 1582 Business Combinations, which replaces Section 1581. This new standard aligns accounting for business combinations under Canadian GAAP with IFRS and is effective for business combinations entered into on or after January 1, 2011. The new standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the acquisition date. The adoption of the revised standard is expected to impact the Company's financial statements only to the extent that business combinations are entered into after the effective date.

(ii) "Consolidated Financial Statements", Section 1601, which together with "Non-controlling Interest", Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. It is not anticipated that the adoption of this standard will have a material impact on the Company's Consolidated Financial Statements.

(iii) "Non-controlling Interest", Section 1602. The standard establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. This standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. It is not anticipated that the adoption of this standard will have a material impact on the Company's Consolidated Financial Statements.

International Financial Reporting Standards. In February 2008, the CICA's Accounting Standards Board confirmed that publicly accountable profit-oriented enterprises will be required to use International Financial Reporting Standards ("IFRS") which will replace Canadian GAAP in 2011. The Company will be required to report its results in interim and annual financial statements in accordance with IFRS beginning with the first quarter of 2011. The Company is developing a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information. The Company has analyzed its current accounting policies and completed a preliminary evaluation of the changes that will be necessary and alternatives that are available. These accounting policy decisions are being finalized during 2010. The following summarizes our current understanding of the major impact of IFRS on accounting policies. The areas that will have the most significant impact on the Company's financial statements and which are affected by the IFRS changeover are: property, plant and equipment, asset retirement obligations; asset impairment testing; income taxes, and functional currency. Following is an overview of these areas:

Property, Plant and Equipment

Under Canadian GAAP the Company currently follows the CICA's guideline of full cost accounting under which all costs directly associated with the acquisition of, exploration for, and development of oil and gas reserves are capitalized on a country by country cost centre basis. Costs accumulated within each cost centre are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs.

Under IFRS, the net carrying value of property interests are segregated between evaluation and exploration assets and development and production (D&P) assets. The determining factor will be when the technical feasibility and the commercial viability of extracting a mineral resource have been demonstrated. Development costs include those expenditures where technical and commercial viability have been determined. D&P assets are segregated into cash generating units for purposes of impairment testing. Amortization or depletion of component costs accumulated within cash generating units can be calculated using alternative acceptable methods. The Company has identified its separate cash generating units.

Asset Retirement Obligations ("ARO")

Currently under Canadian GAAP, ARO is measured as the estimated fair value of the retirement expenditures expected to be incurred in the future. A credit-adjusted risk-free rate is used to present-value the future estimated costs. In addition, existing liabilities are not re-measured at reporting dates using current discount rates. Under IFRS, ARO is measured as the best estimate of the expenditure to be incurred and will require the use of current discount rates at each measurement date. As a result of the IFRS 1 exemption, The Company will be required to revalue its January 1, 2010 ARO balance and recognize this adjustment into retained earnings.

Asset Impairment Tests

Under Canadian GAAP, the Company is required to recognize an impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss is recognized, the loss is measured as the amount by which the carrying value exceeds the sum of the discounted future net cash flows of the proved and probable reserves plus the costs of unproved properties. Under IFRS, The Company will be required to recognize an impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of the fair value less the cost to sell and the value in use. Impairment losses are reversed when there is an increase in the recoverable amount. The Company has ascertained its cash-generating units based on the independence of cash flows from other assets or other groups of assets.

Income Taxes

The Company's future income tax liability will be impacted by the restatements and the adoption of the IFRS changes noted above. The requirements under IFRS for future income taxes are similar to those required under Canadian GAAP, however could have a material impact on the Company's financial statements.

The differences described above are those existing based on Canadian GAAP and IFRS pronouncements that currently exist. The Company has not finalized quantifying the effects of these differences. The intention here is to highlight those areas believed to be the most significant to the Company. Furthermore, the IASB has significant ongoing projects that could affect the Company's financial statements in future years.

Functional Currency

IAS 21, The Effects of Changes in Foreign Exchange Rates, requires that the functional currency of each entity in a consolidated group be determined separately based on the currency of the primary economic environment in which the entity operates. A list of primary and secondary indicators is used under IFRS in this determination and these differ in content and emphasis to a certain degree from those factors used under Canadian GAAP. The parent Company and all of its US subsidiaries operated with the Canadian dollar as their functional currency under Canadian GAAP. The impact of this standard is currently being evaluated.

Non-GAAP Financial Measurements

This document contains the term "netback", which does not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Netbacks are used by the Company as key measures of performance and are not intended to represent operating profit nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Netbacks are determined by deducting royalties, production expenses and transportation and selling expenses from oil and gas sales revenue.

Other Measurements

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a Boe basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term boe may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf equivalent to one Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Potential Risks and Uncertainties

The resource industry is highly competitive and, in addition, exposes the Company to a number of risks. Resource exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. It is also highly capital intensive and the ability to complete a development project may be dependent on the Company's ability to raise additional capital. In certain cases, this may be achieved only through joint ventures or other relationships, which would reduce the Company's ownership interest in the project. There is no assurance that development operations will prove successful.

In addition to the risks and uncertainties identified above, this Management’s Discussion and Analysis contains several forward-looking statements, which are also subject to unknown and uncertain risks, uncertainties and other factors that could cause actual results to differ materially from any future results expressed or implied by such forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements.

Share Capital

Authorized capital:

25 million preference shares of no par value
Unlimited common shares of no par value

Issued and outstanding at May 21, 2010:

1,000 preference shares (held by a wholly-owned subsidiary of the Company)
149,951,319 common shares issued

Warrants outstanding at May 21, 2010 were 33,994,829 warrants (See table set forth under “**Liquidity and Capital Resources”)**.

Agency Options outstanding at May 21, 2010 were 376,845 options. (See table set forth under “**Liquidity and Capital Resources”)**.

Common stock options outstanding at May 21, 2010 were as follows:

Number Authorized	Date of Agreement	Exercise or Issue Price	Expiry Date
100,000	July 26, 2005	$0.95	July 26, 2010
50,000	December 28, 2005	$0.60	December 28, 2010
240,000	December 29, 2006	$0.59	December 29, 2011
1,350,000	December 21, 2007	$1.05	December 21, 2012
25,000	January 21, 2008	$1.05	January 21, 2013
25,000	February 7, 2008	$1.05	February 7, 2013
100,000	April 14, 2008	$1.15	April 14, 2013
250,000	June 3, 2008	$1.17	June 3, 2013
950,000	June 30, 2008	$1.35	June 30, 2013
100,000	October 9, 2008	$1.00	October 6, 2013
2,880,000	December 11, 2008	$0.30	December 11, 2013
140,000	March 11, 2009	$0.30	March 11, 2014
1,034,000	April 16, 2009	$0.44	April 16, 2014
850,000	August 29, 2009	$0.30	August 29, 2014
2,800,000	September 15, 2009	$0.25	September 15, 2014
200,000	November 2, 2009	$0.28	November 2, 2014
166,000	December 4, 2009	$0.23	December 4, 2014
150,000	April 22, 2010	$0.28	April 22, 2011
225,000	May 12, 2010	$0.30	May 12, 2011
11,635,000			