CANADA ENERGY PARTNERS INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE NINE MONTHS ENDED JANUARY 31, 2010

Background

The following management discussion and analysis and financial review, prepared as at March 28, 2010, should be read in conjunction with the Company's interim financial statements for the nine months ended January 31, 2010, and audited financial statements for the years ended April 30, 2009 and 2008, and related notes attached thereto. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Except as otherwise disclosed, all dollar figures in this report are stated in Canadian dollars. Additional information relevant to the Company can be found on the SEDAR website at www.sedar.com.

Forward Looking Statements

Certain of the statements made and information contained herein is "forward-looking information" within the meaning of the British Columbia Securities Act. These statements relate to future events or the Company's future performance. 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", "propose", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar 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 those 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 this MD&A should not be unduly relied upon by investors as actual results may vary. These statements speak only as of the date of this MD&A and are expressly qualified, in their entirety, by this cautionary statement. In particular, this MD&A contains forward-looking statements, pertaining to the following: capital expenditure programs, development of resources, treatment under governmental and taxation regimes, expectations regarding the Company's ability to raise capital, expenditures to be made by the Company and its joint venture partners on its properties and work plans to be conducted. With respect to forward-looking statements listed above and contained in the MD&A, the Company has made assumptions regarding, among other things:

- uncertainties relating to receiving well permits in British Columbia;
- the impact of increasing competition in shale gas business;
- unpredictable changes to the market prices for natural gas;
- exploration and developments costs for its properties;
- availability of additional financing or joint-venture partners;
- anticipated results of exploration and development activities;
- the Company's ability to obtain additional financing on satisfactory terms.

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 MD&A, volatility in the market price for natural gas; uncertainties associated with estimating resources; geological, technical, drilling and processing problems; liabilities and risks, including environmental liabilities and risks, inherent in natural gas extraction operations; fluctuations in currencies and interest rates; incorrect assessments of the value of acquisitions; unanticipated results of exploration activities; competition for, amongst other things, capital, undeveloped lands and skilled personnel; lack of availability of additional financing and/or joint venture partners and unpredictable weather conditions.

Investors should not place undue reliance on forward-looking statements as the plans, intentions or expectations upon which they are based might not occur. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. The Company does not undertake any obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by law.

Company Overview

Canada Energy Partners Inc. ("the Company" or "Canada Energy" or "CE") is an independent natural gas exploration and development company primarily focused on unconventional resource opportunities in northeast British Columbia. The Company was formed on May 18, 2006, and became a publicly listed entity under symbol "CE" on the TSX Venture Exchange on November 22, 2006. The Company was formed for the purpose of acquiring interests in the Peace River Coalbed Methane ("CBM") Project and became an active explorer in northeast British Columbia.

Canada Energy has accumulated 65 gross sections or approximately 42,100 gross acres of drilling licenses with deep rights including Doig/Montney Formation and 92 gross (56 net) sections or approximately 58,800 gross acres of shallow rights including Moosebar and Gething Formations in northeast British Columbia. The Company has three project areas: Peace River, Monias, and Moberly.

In January 2009, the gas sales from eight CBM wells commenced at Peace River. In March 2010 the Company received notice from the Operator of the Peace River CBM Project that it intends to shut-in the eight producing CBM wells prior to May 1, 2010. The gas flow rate from the eight wells has been increasing steadily while dewatering since the start of production in January 2009. The decision to shut the wells in was based upon continued monthly operating losses due to low gas prices and a longer than expected dewatering time to obtain gas production rates necessary to generate a positive cash flow. The Company continues to believe that the CBM Project has commercial potential and will put the Project on care and maintenance. The shut-in wells can be restarted in the future upon improvement in the gas prices.

In addition to the CBM project, the Company has an active deep formations exploration program at Peace River and Moberly funded by its joint venture partner Crew Energy Inc. ("Crew"). Canada Energy's current focus is the development of the Montney formation in northeast British Columbia.

Significant Events

During the nine months ended January 31, 2010, and up to the date of this report, the Company:

- received notice from the Operator of the Peace River CBM Project that it intends to shut-in the eight producing CBM wells prior to May 1, 2010;
- acquired an aggregate 1.5% overriding royalty interest on certain portions of the Company's land based in northeast British Columbia from two arm's-length parties (the "Vendors") in consideration for the issuance of 800,000 common shares of the Company. The shares are subject to regulatory holding period of four months. The overriding royalty covered the majority of the Company's deep and shallow rights;
- drilled the second Montney well on Peace River Project. The multi-stage frac job on this first horizontal Montney well will be performed after the removal of spring road bans by the British Columbia Ministry of Transportation, which is expected in June 2010.
- Provided an update on the Company's Shallow Rights exploration programs in northeast British Columbia. The exploration programs included the Moosebar Shale horizontal well on the Peace River Project and the CBM horizontal well on the farm-in lands adjacent to its Monias Prospect. The Company drilled its Portage a-C100-D/94-B-1 well on the Peace River Project as a horizontal exploration well in the Moosebar Shale. The well reached the targeted 1,000 metres of horizontal displacement. The well is currently shut-in pending a future fracture stimulation test.

  Canada Energy drilled the A9-23-81-22 CBM well on the farm-in lands adjacent to its Monias Prospect as a horizontal exploration well in the Gething formation. Drilling problems were encountered during the drilling of this well which prevented reaching the targeted horizontal lengths. Nevertheless, the well was completed and production tested from February to mid-May 2009 and further evaluated. The test rates have been deemed uneconomic in the current natural gas pricing environment. The well has been shut-in for possible future utility pending increased gas prices. The well is cased and can be utilized for additional horizontal drilling in the coals in the future. The Company has earned a 70% interest in the Shallow Rights in two sections of the farm-in lands and has relinquished its farm-in rights to 6 sections because of the near term drilling requirements and the current low gas prices.

- Received approval from the TSX Venture Exchange (the "Exchange") to commence a normal course issuer bid (the "Bid") to purchase up to 4,117,814 of its common shares ("Shares"), representing 5% of the Company's 82,356,284 issued and outstanding shares, as at May 12, 2009. To date the Company repurchased 543,000 shares for $331,070.

Operations Update

The Company commenced gas sales from its 8 wells on production in January 2009. Six of the eight wells have dewatered sufficiently to contribute significant gas thus far and are averaging approximately 100 MCF/D gross. The fluid rates indicate excellent permeability in the coals and we expect the gas volumes to continue increasing for several years before peaking and rolling over into a long shallow decline.

The Company has drilled four Montney test wells on its acreage; three wells with Crew and one well with West. All four wells were cased and are shut-in pending completions in the Montney. Crew is currently preparing to frac the first horizontal Montney formation well at Peace River and is obligated to spud another horizontal well by July 15, 2010. The Company is carried for drilling and completion costs for the 2010 program.

Crew and the Company acquired 2 additional sections of Deep Rights at Peace River in the September 2009 lease sale, bringing their total JV lands to 57 gross sections.

Outlook

By the end of 2010, the Company will participate in the drilling of one Montney exploration well and two Montney completions, all at no cost to Canada Energy. We will monitor gas prices and performance of the CBM Project and move forward if and when gas prices and performance are in proper alignment, and continue to seek additional exploration and acquisition opportunities in northeast BC.

Projects Overview

Joint Venture with Crew Energy Inc.

In March 2008, the Company entered into a joint venture agreement with Crew Energy Inc. (TSX: CR; "Crew Energy" or "JV Partner") to explore the Montney/Doig Formation on Canada Energy's Peace River and Moberly prospects in northeast British Columbia.

The joint exploration program between Canada Energy and Crew Energy covers 57 sections (approximately 36,991 acres) of lands held by Canada Energy. Crew Energy operates the project and will earn a 50% working interest in the subject lands upon completion, at its sole expense, of the remaining exploration program estimated to cost $15 million.

Peace River Project

The JV Partner completed a 28.5 square mile three-dimensional seismic survey of the Peace River Project in 2008. One Montney well was drilled and cased during 2008 and is shut-in pending completion. Several prospective deep formations, including the Montney, have been identified in this well and on the three-dimensional seismic survey.

Under the Joint Venture Agreement, the JV Partner will complete the first horizontal well and spud the next horizontal well by July 15th, 2010. The Company has a $2.5 million Letter of Credit provided by the JV Partner, which would be called should the JV partner fail to fulfill the commitment.

Talisman Energy Inc. is active in Montney exploration on their Farrell Project, immediately north of the CE's Peace River Project. Talisman has drilled nine Montney wells on the Farrell Project, which is on tectonic and depositional strike with CE's Peace River Project. Talisman tested two vertical wells at 4 MMCF/D and 1.5 MMCF/D and the first horizontal well at 7.3 MMCF/D. They also have 22 additional Montney well authorizations on the Farrell Project. They have publicly announced that they have spent $300 million acquiring leases in the Montney trend and expect to spend $7.5 billion in Montney exploration and development over the next ten years.

The British Columbia Provincial lease sale of October 21, 2009, saw the purchase of 4 drilling licenses comprising 50,302 acres for $279 million ($5,546 per acre) in the Farrell-Altares-Kobes-Cypress area on depositional and tectonic strike with CE's Peace River Project.

Moberly Prospect

The JV Partner drilled an initial well on the Moberly Prospect in early 2009. Several prospective deep formations including the Montney have been identified in this well. Casing has been set on the initial well and the well is shut-in pending completion testing.

Crew has experienced significant success in the Montney formation in northeast British Columbia in their Septimus Project east of Peace River project, having tested the Montney at rates up to 17.6 MMCF/D. CE believes that Crew brings strategic expertise in the Montney to the Joint Venture.

Joint Venture with GeoMet Inc.

Canada Energy is also developing the Peace River CBM Project with Hudson's Hope Gas Ltd., a subsidiary of GeoMet Inc. (NASDAQ: GMET). The Peace River CBM Project covers Shallow Rights on approximately 50,788 gross (25,394 net) acres near Hudson's Hope, British Columbia. The 2008 Development Program included the drilling and completion of five (5) new production wells, the connection of three existing wells, construction and installation of gas treating and compression facilities, and a pipeline and connection to Spectra's (formerly Duke Energy's) transcontinental pipeline. Initial dewatering of the eight connected wells began in calendar Q3 & Q4 of 2008. The gas plant/compressor station, pipeline connection, and gathering system were completed in December 2008, and production and gas sales began in January, 2009.

Joint Venture with West Energy Ltd.

On April 1, 2008, the Company announced a joint venture with West Energy Ltd. (TSX:WTL) ("West") on the deep rights of the Company's Monias Prospect. The Company retained all shallow rights to the base of the Nikanassin formation. Subsequently, West Energy relinquished back to CE the right to earn in 4 sections of deep rights on the Monias Prospect.

Pursuant to the terms of the Agreement, West agreed to conduct an exploration program, the primary purpose of which is to test the potential of the Montney formation. According to the joint venture agreement, West operates the project. The initial program consisted of a three-dimensional seismic project over the majority of the Monias Prospect lands. West drilled and cased one well on the Monias Prospect. The Company has a legal dispute with West as to whether or not West has earned an interest in four sections. West recently announced the proposed acquisition of the company by Daylight Energy Trust anticipated to close in May 2010.

Shell recently drilled a Montney test well 1.5 miles southeast of CE's southeast corner of the Monias Prospect. Monterrey Exploration has acreage adjacent to CE's Monias acreage and has drilled two vertical and one horizontal Montney wells. The horizontal well, approximately 4 miles southeast of CE's lease line, tested at 9 MMCF/D.

Contingency

The Company has commenced legal proceedings in the Court of Queen's Bench of Alberta against West for a declaration that West has failed to earn a 65% interest and has no interest in the petroleum and natural gas rights below the Nikanassin formation (deep rights) on the four sections (2,608 acres) located within the Company's Monias Prospect pursuant to a seismic option agreement. West filed a statement of defense and counterclaim. The outcome of this legal action is not determinable and the estimate of the contingent gain/loss cannot be made as of the date of this report.

<u>Operated by Canada Energy Partners</u>

<u>Monias Prospect – shallow rights</u>

The Company's Monias Prospect consists of approximately 6,517 gross acres or 10 sections (10 square miles) and 6,126 net acres or 9.4 net sections and is located in the Peace River Plains area near Fort St. John, British Columbia. The Company owns 100% working interest in the shallow rights on eight sections, a 70% working interest in 2 sections, a 100% working interest in the deep rights on four sections, with the disputation with West covering 4 additional sections of deep rights.

One of two sections are subject to a 10% royalty on gas, a 5% - 10% royalty on oil production and both sections are subject to a back-in interest of 4.375% after project payout plus $2,000,000.

<u>Peace River Project – Moosebar Shale rights</u>

In November 2008 Canada Energy entered into a farm-in agreement (the "Agreement") with GeoMet, Inc. for Moosebar Shale shallow rights on its Peace River Project. The Company drilled an initial Moosebar horizontal test well and has earned a total of 87.5% interest in 2 sections, subject to final completion or plug and abandonment. The Company has relinquished further drilling rights under the Farmout.

Peace River CBM Project – Technical Summary

The Company had Netherland, Sewell & Associates, Inc. ("NSA") provide a third iteration of their independent reserve assessment and evaluation report on the Peace River CBM Project effective April 30th, 2009. Highlights of the Report are as follows:

- Total gas-in-place for the Project is 1.466 Trillion Cubic Feet ("TCF") in the coal formations. NSA did not evaluate gas-in-place in the shale or deeper formations.

- Recoverable gas from the Project is estimated at 733.1 billion cubic feet ("BCF"); including proved probable, possible and contingent resource.

- The total estimated remaining recoverable gas reserves and remaining contingent gas resources net to the Company are 260.4 BCF, including 0.2 BCF proved developed producing reserves ("PDP"), 11.9 BCF probable reserves, 40.7 BCF possible reserves and 207.6 BCF contingent resources. The proved developed producing is nominal due to this being the first commercial CBM project in British Columbia and the producing wells being so early in the dewatering process.

- The estimated future net cash flow to the Company, net of development costs, operating costs, royalties, shrinkage and abandonment costs, but before income taxes, from reserves and contingent resources is $1.624 billion. The PV10% of reserves and contingent resources is $458.4 million.

The summary of the Report is presented below:

	Gross BCF (1)	Net BCF	Net cash flow (2) MM$Cdn	PV10%(2) MM$Cdn
PDP	0.86	0.2	0.7	0.6
Probable	33.4	11.9	75.6	32.1
Possible	115.8	40.7	223.4	70.1
Contingent Resource	583.1	207.6	1,325.1	355.6
Totals	733.2	260.4	1,624.8	458.4

(1) Coal only; raw gas including carbon dioxide. Netherland did not evaluate the shales. Deep Rights were not evaluated.

(2) Estimated future net cash and estimated PV10% values do not represent fair market value.

The study included 300 gross wells on 170-acre spacing. The NSA study has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Net present value was calculated before income taxes of future net revenue from the Company's resources using forecast prices and costs based on the April 1, 2009 quarterly price forecasts prepared by Canadian independent consultants. All evaluations and reviews of future cash flows are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves or resources have been assigned. It should not be assumed that the estimates of future net revenues presented represent the fair value of the reserves or resources. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of natural gas reserves or resources provided herein are estimates only and there is no guarantee that the estimates reserves or resources will be recovered. Actual natural gas reserves and resources may be greater that or less that the estimates provided herein.

Amounts representing Contingent Resources were calculated using deterministic methods and represent the "best estimate (2C)" or mid-range case. Low estimate (1C) and high estimate (3C) cases were not prepared.

The April 30, 2009 NSA report was prepared using a forecast price for the local Westcoast Station 2 and was adjusted for energy content, gathering and compression fees, transportation fees and a regional price differential, starting at CN$3.81/MMBtu, escalating to CN$9.13/MMBtu in 2018, and escalating at 2% per year thereafter.

The NSA Report was prepared in accordance with the requirements of NI 51-101.

It is noteworthy that GeoMet had their reserve study done by DeGolyer & MacNaughton who ascribed 4 BCF 'proved' and 22 BCF 'probable' for GeoMet's interest in the Peace River Project. This '2P' reserve estimate reflects a significantly higher "2P" reserve number than the Netherland study.

Definitions:

"Proved reserves" are those quantities of petroleum, which by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

"Probable reserves" are those additional Reserves which analysis of geosciences and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

"Possible reserves" are those additional reserves which analysis of geosciences and engineering data indicate are less likely to be recovered than probable reserves.

"Contingent resources" are defined as those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but is not currently economic. The contingencies that result in the classification of the Gething CBM as a contingent resource include, but are not limited to: permeability to gas, gas saturation and/or content, an appropriate and successful field development plan, corporate commitment, and economic factors.

"Discovered resources" are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into economic and uneconomic categories, with the estimated future recoverable portion classified as reserves and contingent resources, respectively. The reported Discovered Resource cannot be classified into one of the sub-categories of reserve, contingent resource, or unrecoverable resource at this time because it is not possible to estimate the portion of the discovered resource that could be recoverable and/or unrecoverable due to the lack of commercial tests or production testing in the vicinity of Company interest lands. There is no certainty that it will be technically or economically viable to produce any portion of the reported Discovered Resources.

Through 2007, twenty-two wells had been drilled on the Project to date, including 9 production tested wells, 4 wells for water disposal and 4 core holes. Each of the production tested wells was allowed to flow for 5-9 months under temporary flaring permits to test the productive characteristics of the coal seams. Production rates per well ranged up to 180 MCF/d with up to 150 bw/d (barrels water per day).

Multiple techniques were used to stimulate the production tested wells, with one technique yielding significantly better results. The average flow rate at the end of the testing period on the wells stimulated with the best completion technique was 82 MCF/d and 32 bw/d with an average predicted peak rate of 482 MCF/d. Coalbed methane reservoirs similar to the Project usually increase in production over a period of several years before peaking and then going into a long, slow decline. All five of the production wells drilled and completed in 2008 manifested higher total fluid productivity than all 22 prior wells.

In 2007, Advanced Resources International, Inc., a Houston, Texas, reservoir engineering consulting firm was engaged by the Operator and performed reservoir simulations on several of the test wells. The simulations on the wells with the best stimulation technique, based on 160 acre spacing, predicted peak production rates 3-7 years after initial production of 360-685 MCF/d, with an average predicted peak rate of 482 MCF/d and an average net methane recovery of 2.83 BCF per well. The reservoir simulations predicted up to 40 years of productive life. The average projected recovery for these simulated wells, assuming the projected recoveries were attained, would be approximately 8 times the average recovery of a Horseshoe Canyon CBM well and 2-4 times the average recovery of a Manville horizontal CBM well on a per section basis. (Comparison derived from Sproule Research Report "Evolution of CBM Resources to Reserves and Commerciality in Alberta" April 17, 2007).

Netherland Sewell & Associates, Inc. ("Netherland") and Sproule Associates Limited ("Sproule"), as reported in the Company's July 16, 2007 news release, both utilized all the test data in their Resource Reports.

Reservoir simulations are forward-looking estimates of future production based upon the industry's accumulated knowledge of the production histories and characteristics of existing coalbed methane fields and the application of that historical knowledge together with geological and engineering principles by computer analogue to emerging coalbed methane fields. There is no assurance that the predicted production profile will be realized due to the unique characteristics of each coal- bed methane basin.

Peace River CBM Project - Regional Geology and Setting

Most of the bituminous coal resources in the WCSB are contained within the Rocky Mountain Front Ranges and Foothills of British Columbia and Alberta. Coal deposits have been known to exist in the belt that extends almost 1,200 kilometers northwestward along the eastern side of the Rocky Mountains. The region can be divided into three geologically, physiographically and geographically distinct coal-bearing sub-divisions—the Rocky Mountain Front Ranges, the Inner Foothills Belt, and the Outer Foothills Belt.

The Rocky Mountain Front Ranges are characterized by thrust sheets of mainly Paleozoic carbonates bounded by faults that extend for tens of kilometers in length and have displacement up to several kilometers. Subsidiary thrust, tear faults and folds have further deformed the individual sheets. Jurassic-Cretaceous coal measures occur in the Rocky Mountain Front Ranges of southeastern British Columbia and southwestern Alberta.

Deformed Mesozoic and some Cenozoic clastic rocks, which extend from the Front Ranges to the eastern edge of the Disturbed Belt, constitute the Rocky Mountain Foothills. Lower Cretaceous coal is distributed through most of the Western Sedimentary Basin.

Coals of the Gething Formation in the Peace River Plains are relatively undisturbed, east of the Inner Foothills Belt, the topographically distinct belt of relatively low relief is in front of the disturbed belt.

Peace River CBM Project - General Stratigraphy

Most of the Plains region is underlain by coal-bearing formations; individual coals thicken, thin, split, coalesce and pinchout in response to depositional and erosional conditions under which the original peat accumulated. Some coal beds have exceptional lateral continuity and are used as stratigraphic markers, while others are extremely variable in thickness and lateral extent.

With the exception of the areas adjacent to the Foothills, where rank may be as high as low volatile bituminous, near surface coals in the Plains region range in rank from lignite in the east to bituminous in the west, i.e. rank increases with depth and toward the west. These coals may be correlated in age and stratigraphic position with the generally low-medium volatile bituminous coals of the Foothills.

The oldest coal-bearing rocks are the Jurassic-Cretaceous Kootenay Group of the mountains and foothills. Thick coals are present in the Lower Cretaceous Mannville Groups of the Plains. Equivalent coals are exposed in the mountains and foothills, where they form part of the Luscar Group. Equivalent to Luscar in northeastern British Columbia are the Lower Cretaceous Bullhead Group and part of the Fort St. John Group.

The Lower Cretaceous Bullhead Group includes the Cadomin Formation and the Gething Formation. The Fort St. John Group, where the main coal-bearing sediments are in the Gates Formation, overlies the Bullhead Group.

In the area of the Peace River Plains, where the Project is situated, most of the upper coal-bearing Gates Formation has been eroded along with the rest of the Fort St. John Group and other overlying Upper Cretaceous/Tertiary sediments. The wedge of sediments overlying the Gething Formation thickens from east to west (from 665 to 810 metres). The Gething Formation comprises an interstratified, mainly non-marine, fluvial-deltaic sequence of sandstone, siltstone, mudstone, coal conglomerate, and is deposited over fluvial-alluvial fan strata of the Cadomin Formation. Extensive mining exploration west of the Company land indicates that the Gething Formation thickens to over 1,000 metres and contains more than 100 coal beds, each ranging in thickness from a few centimeters to over 4.3 metres.

Capping the Gething Formation within the Plains region is lenticular shoreline marine sandstone of the Bluesky Formation and marine shale of the Moosebar Formation.

Peace River CBM Project - CBM and Shale Gas Targets

The Project is located in northeastern British Columbia, near the Town of Hudson's Hope. The topography of the area is of low relief, mixed farmland-pasture, with relatively easy access. The area has seen limited petroleum exploration in the past. In 1921, the British Columbia government drilled six wells and the industry had drilled only five wells prior to 1983 in the area. The Spectra Energy pipeline crosses the southwestern part of the Company's land.

The Project is located in Townships 81-82, Ranges 24-26, W6M, and in 1/93-0-16, A, H-94-A-4 and A, H/94-B-1 (BC Grid). The lands of the Project are mainly contiguous except for 13 sections (approximately 16% of the Project's acreage), which are located southeast of the Peace River, from a development perspective and consist of approximately 20,286 hectares (or 78.3 sections) of petroleum and natural gas rights.

The Moosebar Formation is present under most of the Project. The thickness of the Moosebar shale ranges from about 150 to 247 metres.

The Gething Formation is present under the entire Project. Core data, gas analyses and logs interpretation were used in the assessment of parameters to estimate the discovered resources in place.

To estimate the unconventional discovered resources, the Gething deposits were subdivided into the following rock types: coal, dirty coal, coaly shale and shale.

The net coal thickness was determined from the available log interpretation, using 1.75 g/cc density cutoff. Ash content from the core analyses would be less than 50 percent. The coals are discontinuous and correlation of individual seams is difficult.

Average gas contents and densities for each type of lithology in the Gething and Moosebar Formations were determined from core analyses of the three wells, provided by the Company.

The principal risk for the Company is the producibility of the coals and other types of rock. Ongoing testing of the Company's test holes will gather further data to assist in assessing the potential productivity of the Gething and Moosebar Formations.

Deep rights, northeast British Columbia

Peace River Project

The Company's 100% ownership in the 51 sections and 50% interest in 2 sections of deep rights on the Peace River Project is subject to the Crew Joint Venture discussed earlier in this report, where Crew has the right to earn 50% working interest in the Peace River Prospect. 6 of the 53 sections are also subject to 12.5% Triumph back-in as described below. In September 2009 Crew and the Company have acquired the two latest sections of Deep Rights, bringing the total to 53 gross sections on the Peace River Project.

Moberly Prospect

The Company has 100% working interest in Moberly Prospect consisting of approximately 2,600 acres and located in the Peace River Plains area south of Fort St. John, British Columbia. The Company's interest in the Moberly Prospect is subject to a joint venture agreement by Crew Energy as previously discussed in this report. The Company's interest will be subject to Crown royalties, 10.485% back-in after project payout plus $2,000,000 by Triumph and 2.43% overriding royalty interest. The Prospect has stacked pay objectives – CBM, shale and conventional gas potential.

Monias Prospect

The Company's Monias Prospect consisting of approximately 6,517 gross acres or 10 sections (10 square miles) and located in the Peace River Plains area south of Fort St. John, British Columbia. The Company owns 100% working interest in the shallow and deep rights on 8 sections and a 70% interest in the Shallow Rights to 2 sections. Four of these sections are subject to the joint venture agreement with West Energy Ltd. ("West") as discussed earlier in this report.

Monias Prospect has stacked pay objectives – CBM, shale and conventional gas potential. There is a raw gas gathering system on the property and is approximately < 1 mile to tie in. Two of the 12 sections are subject to a 15% royalty on gas, a 5% - 15% royalty on oil production to unrelated third parties and a 6.25% after-payout working interest by Triumph.

Summary of Financial Results

For the nine months ended January 31, 2010, the Company reported a net loss of $1,212,351 (2009 - $3,634,729) of which loss of $1,189,084 (2009 - $3,846,946) can be attributed to general and administrative expenses and a loss of $23,267 (2009 – income of $212,217) to other items. General and administrative expenses are discussed below in Results of Operations.

Results of Operations

In January 2009, the Company commenced gas sales from eight wells on its Peace River CBM Project. The Company's share of production revenue was $141,719 during the nine months ended January 31, 2010 (nine months ended January 31, 2009 - $10,061). Production from the CBM wells continues to incline. Six of the eight wells are producing significant quantities of gas; the two remaining high water wells appear to be on the verge of starting producing gas. Revenue recognized during the development stage was presented as a reduction of related deferred development costs in accordance with the requirements of the CICA Handbook AcG-11, Enterprises in the development stage.

During the nine months ended January 31, 2010, the Company incurred $1,189,084 (2009 - $3,846,946) of general and administrative expenses. Significant expenditures were incurred in the following categories:

- Administrative and management fees of $353,105 (2009 – $383,645) included salaries of the Company's managemetn and staff. The fees were slightly lower in 2010 due to the reduction of one part-time management position in 2010.

- Corporate development expense of $69,509 (2009 - $171,391) consists mainly of fees and expenses paid to business development consultant. The decrease in this expense category is due to the decrease in activities during the nine months ended January 31, 2010;

- Travel expenses of $33,310 (2009 - $104,790) decreased mainly due to the decrease in travel and the site visits to the Company's properties in 2010;

- Stock based compensation expense of $267,800 (2009 - $2,754,587) is non-cash and represents the estimated fair value of stock options vested during the periods. The stock-based compensation charge was lower in the current period mostly because the number of option granted and the ascribed value was considerably lower than during the comparable period of last year. Stock-based compensation expense is accounted for at fair value as determined by the Black Scholes Option Pricing Model using estimates that are believed to approximate the volatility of the trading price of the Company's stock, the expected lives of awards of stock-based compensation, the fair value of the Company's stock and risk-free interest rate;

- Office and miscellaneous expense of $99,525 (2009 - $104,582) includes bank charges and interest on bank loan, office supplies, telephone, insurance, professional fees and dues;

- Rent of $82,347 (2009- $79,314) includes rent of Company's offices in Vancouver, Calgary (up to September 2009), Baton Rouge, and Dallas;

- Legal expenses of $47,528 (2009 - $50,753) include corporate and West litigation costs;

- General exploration of $74,115 (2009 - $7,516) increased mainly due to the Company's efforts on the search of new opportunities in northeast BC.

- Audit and accounting of $58,129 (2009 - $62,640) consists mainly estimated accruals for fiscal year- end audit and accounting fees.

The Company capitalized $971,413, net of $141,719 gas production revenue, on the Peace River CBM Project, $63,004 on Monias Prospect, and $3,068 on Moberly Prospect during the nine months ended January 31, 2010. There were no properties written off during the nine months ended January 31, 2010, or in prior years.

Summary of Quarterly Results and Second Quarter

The following is a summary of the Company's selected financial results for the eight most recently completed quarters. The information has been prepared in accordance with Canadian GAAP.

	Fiscal 2010			**Fiscal 2009**				**Fiscal 2008**
	Q3 $	**Q2 $**	**Q1 $**	**Q4 $**	**Q3 $**	**Q2 $**	**Q1 $**	**Q4 $**
Total assets	92,139,128	92,414,271	92,909,078	94,288,404	95,809,728	95,718,223	94,297,032	71,724,841
Long term financial liabilities	-	-	-	-	-	-	-	-
Total revenues	-	-	-	-	-	-	-	-
General and administrative expenses	267,780	365,810	555,495	438,049	343,351	984,732	2,518,863	460,821
Net (loss)/income	(263,455)	(396,833)	(552,063)	582,790	(356,518)	(838,709)	(2,439,502)	1,047,035
Net (loss)/income per common share basic and diluted	(0.00)	(0.01)	(0.01)	0.00	(0.00)	(0.01)	(0.03)	0.03

Total assets

- decreased by $275,143 during Q3 2010 due to general and administrative expenditures of 262,357 (excluding non-cash itetms), share –repurchase payments of $211,750 offset by increase in accounts payable of $195,511.

- decreased by $494,807 during Q2 2010 due to general and administrative expenditures of $355,934 (excluding non-cash items), share-repurchase payments of $45,445, and decrease in accounts payable of $98,280.

- decreased by $1,379,326 during Q1 2010 due to general and administrative expenditures of $328,895 excluding non-cash stock based compensation and decrease in accounts payables of $1,042,564;

- decreased by $1,521,324 during Q4 2009 due to general and administrative expenditures of $438,049, decrease in accounts payables of $882,215, write-off in the fair value of ABCP of $529,961, offset by $209,568 asset retirement obligation and interest income of $40,104 from the Company's short-term investments;

- there were no significant fluctuations in total assets in Q3, 2009;

- increased by $1,421,191 during Q2 2009 due to the expenditures on the Peace River Project included in accounts payable as at October 31, 2008, offset with general and administrative expenditures;

- increased by $22,572,191 during Q1 2009 due to the net proceeds of $23,314,098 from the financing completed during the period offset with general and administrative expenditures;

General and administrative expenses

- decrease of $98,030 in Q3 2010 compared to Q2 2010 is mainly due to $41,200 decrease in non-cash stock based compensation as there were no stock options vested during Q3 2010; $17,908 decrease in audit and accounting fees is mainly due to the higher audit charge in Q2 2010 related to remaining balance due for work performed in fiscal 2009; $17,739 decrease in general and exploration expenses and decrease in legal expenses of $10,998.

- decrease of $189,688 in Q2 2010 compared to Q1 2010 is mainly due to decrease of $226,600 in non-cash stock based compensation for the stock options vested during Q2 2010 offset with $18,786 increase in audit and tax consulting fees related to work performed in fiscal 2009.

- increase of $117,446 in Q1 2010 compared to Q4 2009 is mainly due to $220,384 increase in stock based compensation for the stock options granted during the Q1 2010 offset with $61,483 decrease in professional fees due to decrease in corporate activities;

- increase of $94,698 in Q4 2009 compared to Q3 2009 is mainly due to $41,570 increase in professional fees due to increase in corporate activities, $27,084 increase in legal expenses due to Company's legal proceedings, and asset retirement obligation depreciation and accreation expenses of $18,020;

- decrease of $641,381 in Q3 2009 compared to Q2 2009 is mainly due to decrease of $629,005 in non-cash stock based compensation for the stock options vested during Q3 2009. There were no other significant fluctuations in individual expenses categories during Q3 2009;

- there were no significant fluctuation in individual expenses categories during Q2 2009 except for $66,500 non-cash stock based compensation for the stock options granted during the Q2 2009 for the 50,000 stock options granted during the Q2 2009 and $540,000 non-cash stock based compensation for the stock options granted during the Q1 2009 and recognized during the Q2 2009 (2,000,000 stock options were granted during the Q1 2009);

- increase of $2,058,042 in Q1 2009 compared to Q4 2008 is mainly due to $2,040,000 non-cash stock based compensation for the stock options granted during the Q1 2009 (2,000,000 stock options were granted during the Q1 2009);

Net loss

- There were no significant fluctuations in individual expese categories during Q2 and Q3 2010 except those descirebed in General and Administrative expenses section of this report.

- Q1 2010 net loss included interest income of $4,697. The decrease in interest income compared to other periods is due to the current state of the credit markets and low interest rates offered by the banks on the Company's deposits;

- Q4 2009 net loss included non-cash future income tax recovery of $1,445,641 due to the tax rate reduction effect on the Company's future income tax liability and $470,934 loss recognized on the a further impairment charge of the Company's asset-backed commercial paper investment in addition to general and administrative expenses discussed above;

- there were no significant fluctuations in individual expense categories during Q3 2009 except for $109,004 part XII.6 tax in respect of a 2007 flow-through financing renounced to the subsribers under the look-back rule in January 2008. This Part XII.6 tax expense was calculated by multiplying the unspent qualified Canadian exploration expenditures ("CEE") at the end of each month (starting with February 2008) by the prescribed monthly interest rate set by Revenue Canada;

- there were no significant fluctuation in individual expense categories during Q2 2009 except stock-based compensation discussed in the above offset with $62,642 increase in interest income from the short-term investments;

- there were no significant fluctuation in individual expense categories during Q1 2009 except stock-based compensation discussed in the above;

Liquidity and Capital Resources

As at January 31, 2010, the Company had a positive working capital of $5,766,987 compared to a positive working capital of $6,592,563 as at October 31, 2009.

As at the date of this MD&A, the Company has a positive working capital of approximately $5,500,000. The working capital does not include the Company's investment in ABCP fair valued at $900,938 (face value $1,712,737).

As at January 31, 2010, the Company had cash and cash equivalents of 7,350,955, accounts receivable and prepaids of $105,972 being available to cover the Company's short-term liabilities of $1,689,940.

During the nine- month period ended January 31, 2010, the Company generated revenue from CBM sales of $141,719 (2009 - $10,061) and recorded interest income of $14,735 (2009 - $300,613) from its short-term investments. The Company is dependent on the equity markets as its major source of future development and exploration activities.

Asset-backed Commercial Paper

At January 31, 2010, long-term investments included Master Asset Vehicle II notes received in exchange for Canadian third-party asset backed commercial paper ("ABCP") held by the Company. These investments were designated as held-for-trading and are accounted for at their fair value.

The market for asset-backed commercial paper not sponsored by banks froze up in early August 2007 after issuers were unable to roll over maturing notes. A Pan-Canadian Investors Committee for Third-Party Structured Asset-Backed Commercial Paper (the "Committee) was tasked with overseeing the restructuring of the ABCP. On January 12, 2009, the Ontario Superior Court approved a complicated and controversial deal to swap essentially non-tradable, mortgage-backed debt for new securities. On January 21, 2009, the Committee announced the successful implementation of the restructuring plan. Upon the restructuring old short-term ABCP notes were exchanged for longer-term notes of various classes with maturities that generally approximate those of the assets previously contained in the underlying conduits. T

As part of the Plan, the Company received new notes of various classes issued by trusts referred to as MAVII, including senior notes Class A-1, subordinated notes Class C, and ineligible tracking notes Class 13. At the time of the restructuring, DBRS assigned a rating "A" to the MAV II Class A-1 notes. The MAV II Class C and Class 13 notes have not been rated by DBRS.

Upon the restructuring, the Company received the replacement notes as follows:

Notes	Maturity Date (1)	Interest Rate (2)	Face Value, $	Fair Value Estimate, $
MAV II Class A-1	December 2056	BA - 0.5%	1,441,880	964,830
MAV II Class C	December 2056	BA + 20%	44,594	4,459
MAV II Class 13 (Ineligible Asset Tracking Notes)			226,263	22,626
Total			1,712,737	991,915
Interest received as at April 30, 2009				(59,026)
Interest received during the nine months ended January 31, 2010				(31,077)
Interest receivable as of January 31, 2010				(874)
Fair value				900,938

(1) Maturity date reflects legal maturity date. Latest maturity date of underlying assets is December 2016.
(2) BA rate is Canadian dollar Bankers Acceptance interest rate with a maturity of 90 days.

Accounting for the exchange of the ABCP for new notes included removal of the ABCP from the Company's balance sheet and recognition of the new notes at their fair value. The new notes are classified as held-for-trading under the Company's Financial Instruments Policy which requires them to be fair valued at each period end with changes in fair value included in the statement of operations in the period in which they arise. The fair value is determined using a discounted cash flow approach based on the maximum use of inputs observed from the market on reporting dates.

The fair value of the Class A-1 notes was established using a discounted cash flow approach based on the following inputs: the notes will pay interest at a rate 0.5% less than the bankers' acceptance ("BA") rate, prospective buyers of these notes estimated to require premium yields 5% over the BA rate, average maturity of Class A -1 Notes estimated to be 7.5 years. The Class C Notes are subordinated to the Class B Notes with respect to payment of interest and principal, and no amounts will be paid with respect to the Class C Notes until the Class B Notes are repaid in full. The Class C notes are viewed as highly speculative with regard to ultimate payment of principal at maturity in 2016. Accordingly, it is expected that Class C notes will trade at approximately 10% of face par value. The fair value of the sub-prime backed Class 13 Notes was calculated as 10% of par value. To date, the Company received a payment of $89,781 which was its share of the accumulated interest and represents accrued interest due under the ABCP Plan of Arrangements. In addition, the Company received $321 on its MAV II Class 13 notes and is entitled to receive $874 on the Company's MAV II Class A-1 notes. The interest received and receivable was accounted for as a reduction of the Company's investment.

There is significant amount of uncertainty in estimating the amount and timing of cash flows associated with these notes. Until an active market develops for the MAV II notes, the fair value will be determined using a discounted cash flow approach based on the maximum use of inputs observed from market conditions on subsequent reporting dates. Therefore, the fair values may change materially in subsequent periods.

The Company secured a $1,376,700 demand non-revolving bridge loan from its bank pending any possible long-term solution to the current liquidity issues affecting the Company's investment in ABCP. The bridge loan is secured by the Company's investment in ABCP. Interest on direct advances is paid at the Bank's prime rate (effective May 22, 2009, the interest rate payable increased to the Bank's prime rate plus 1% and stamping fees increased to 1.5% per annum). The Company paid $20,380 in interest and stamping fees on the loan during the nine- month period ended January 31, 2010.

The Company considers that it has adequate resources to maintain its ongoing operations and current property commitments for 2010 fiscal year but may not have sufficient working capital to fund all of its future development and exploration work. The Company will continue to rely on successfully completing additional equity and/or debt financing to further exploration of its existing and new properties in British Columbia. There can be no assurance that the Company will be successful in obtaining the required financing.

The Company does not know of any trends, demand, commitments, events or uncertainties that will result in, or that are reasonably likely to result in, its liquidity either materially increasing or decreasing at present or in the foreseeable future. Material increases or decreases in liquidity are substantially determined by the success or failure of the development and exploration programs.

Operating Cash Flow

Net cash used for operating activities during the nine- month period ended January 31, 2010, was $704,132 (2009 - $1,752,892). During the period ended January 31, 2009, the company's loss was reduced by interest income of $300,613 earned on the Company's cash and cash equivalents. For the first three quarter of fiscal 2010, the company earned significantly lower interest income of $14,735. Cash used for operating activities, net of non-cash items and interest received from investment in ABCP, consists primarily of the operating loss from the general and administrative expenditures of $897,204 (2009 - $880,142) and changes in non-cash working capital balances of $193,072 (decrease in accounts receivable of $280,450 and decrease in accounts payable and accrued liabilities of $87,378) (2009 –increase in accounts receivable of $515,382 , decrease in accounts payable of $466,372, and increase in other tax liabilities of $109,004).

Financing Activities

There was no inflow of capital from financing activities during the nine-month period ended January 31, 2010. The Company repurchased 443,000 of its common shares according to its issuer bid share repurchase for $273,045. The Company received $25,057,772 from the private placement and exercise of agent's warrants less share issue costs of $1,680,129 during the same period of last year.

Investing Activities

Investing activities required cash of $1,952,461 during the nine months ended January 31, 2010, compared to cash of $11,235,990 used during the same period of last year. Significant increase in the Company's investing activities during the first three quarters of fiscal 2009 is due to the construction on the Company's Peace River CBM Project.

Outstanding Share Data

As at the date of this report, the Company had 82,613,284 common shares and 5,337,500 stock options outstanding. The Company does not have any warrants issued and outstanding.

In May 2009 the Company received approval from TSX Venture Exchange to repurchase up to 4,117,814 of its common shares, representing 5% of the Company's 82,356,284 issued and outstanding shares. The Bid commenced on May 29, 2009, and will end on the earlier of May 28, 2010, or at such time as the Bid has been completed or the Bid is terminated at the Company's discretion. The price paid by the Company for any acquired shares will be the market price at the time of acquisition. All shares purchased under the "Bid" are cancelled. Funding for the "Bid" will be from the Company's working capital. As at the date of this report, the Company repurchased 543,000 common shares for $331,070.

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements

Related Party Transactions

Included in administrative and management services for the nine months ended January 31, 2010, is $8,017 paid by the Company to a company controlled by a Director.

Director of the Company was the original geologist that staked leases comprising of Peace River Project, Monias and Moberly prospects in which the Company acquired interests. Upon acquisitions of working interests in these lands, the Company's working interest is subject to the overriding royalty interests which range from 0.775% to 1% payable to the Director.

The related party transactions incurred during the period were in the normal course of operations and were measured at the exchange value, which represented the amount of consideration established and agreed by the related parties.

Contractual Commitments

a) As at the date of this report, the Company has committed to rent office space for the following amounts:

Location	Start date	End date	Rent per month $	Total commitment $
Vancouver #1501	1-Jan-09 1-Mar-10	28-Feb-10 30-Apr-11	2,670 2,777	2,670 38,878
Vancouver #1521	1-Feb-09 1-Mar-10	28-Feb-10 30-Apr-11	1,290 1,342	1,290 18,788
Baton Rouge, Louisiana	1-Apr-10	31-Mar-13*	US$1,800	US$21,600

**The office lease agreement can be terminated by Lessee after April 1, 2011, and before March 31, 2013, with 120 day written notification to Lessor. Total commitment shown is to March 30, 2011.*

b) Mineral properties commitments are disclosed in Note 3 of the Company's unaudited interim financial statements for the nine months ended January 31, 2010.

Financial Instruments

The Company has designated its financial instruments as follows:

a) Cash and cash equivalents are classified as *"Held-for-trading"*. Their carrying values are equal to its fair values.

b) Accounts receivable, prepaids and deposits are classified as *"Loans and Receivables"*. These financial assets are recorded at values that approximate their amortized cost using the effective interest method.

c) Investments in asset-backed commercial paper and bank loan are designated as *"Held-for-trading"*.

d) Accounts payable and accrued liabilities, are classified as *"Other Financial Liabilities"*. These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method.

The Company may be exposed to risks of varying degrees of significance which could affect its ability to achieve its strategic objectives. The Company manages risks to minimize potential losses. The main objective of the Company's risk management process is to ensure that the risks are properly identified and that the capital base is adequate in relation to those risks. A summary of financial risk factors related to the Company's business are provided in Note 10 of the Company's April 30, 2009, audited financial statements. The additional risks to which the Company is exposed are described below.

Risk Factors

The Company's operations and results are subject to a number of different risks at any given time. These factors, include but are not limited to disclosure regarding exploration, additional financing, project delay, titles to properties, price fluctuations and share price volatility, operating hazards, insurable risks and limitations of insurance, management, and regulatory requirements, environmental regulations risks. Exploration for gas and CBM resources involves a high degree of risk. The cost of conducting programs may be substantial and the likelihood of success is difficult to assess.

Substantial Capital Requirements

The Company anticipates that it will make substantial capital expenditures for the acquisition, exploration, development, and production of CBM reserves in the future. If the Company's revenues or reserves decline, the Company may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Moreover, future activities may require the Company to alter its capitalization significantly. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations or prospects.

Environmental Risks

All phases of the gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of gas, water or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require the Company to incur costs to remedy such discharge. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

Water Disposal

The coal beds from which CBM gas is produced frequently contain water that may hamper the Company's ability to produce gas in commercial quantities or affect the Company's profitability.

Unlike conventional natural gas production, coal beds frequently contain water that must be removed in order for the gas to desorb from the coal and flow to the well bore. The Company's ability to remove and dispose of sufficient quantities of water from the coal seam will determine whether or not the Company can produce gas in commercial quantities. The cost of water disposal may affect the Company's profitability.

Where water produced from the Project fails to meet the quality requirements of applicable regulatory agencies or wells produce water in excess of the applicable volumetric permit limit, the Company may have to shut in wells, reduce drilling activities, or upgrade facilities. The costs to dispose of this produced water may increase if any of the following occur:

- the Company cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality is produced;
- wells produce excess water; or
- new laws and regulations require water to be disposed of in a different manner.

Reliance on Operators and Key Employees

The Company is not the operator on all of its prospects and may not be the operator of certain gas properties in which it acquires an interest. To the extent the Company is not the operator of its gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. The operator may incur liability for liens related to its subcontractors. If subcontractors fail to timely pay for materials and services, the assets of the operator could be subject to materialmen's and workmen's liens. In that event, the operator could incur excess costs in discharging such liens.

In addition, the success of the Company will be largely dependent upon the performance of its management and key employees. The Company does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Company.

Conflicts of Interest

Certain of the directors and officers of the Company are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Company and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the Business Corporations Act.

Permits, Licenses and Government Regulations

Governmental permits and approvals for drilling operations must be obtained for the Project, which can be a costly and time consuming process and result in restrictions on operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of exploration or production operations. For example, GeoMet as the operator of the Project will often be required to prepare and present to federal, provincial or local authorities data pertaining to the effect or impact that proposed exploration for or production of gas may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits that are needed may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict the ability to conduct the operations on the Project or to do so profitably.

Oil and gas exploration is subject to significant regulation. Changes in these regulations may have a material adverse impact on the Company's operations.

Title Matters

Although title reviews on the Company's property interests will be done or have been done to the satisfaction of management of the Company, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the interests of the Company. Such defects in title could result in a reduction of the possible revenue to be received by the Company. In addition, the Company's properties which are held in the form of licences, leases and/or working interests in licences and leases may be adversely affected if the holder of the licence or lease fails to meet the specific requirements of a licence or lease. There can be no assurance that any of the obligations required to maintain such licences or leases will be met. The termination or expiration of such licences, leases or working interests in licences or leases may have a significant material adverse effect on the Company's results of operations and business.

Aboriginal Land Claims

Many lands in British Columbia are or could become subject to aboriginal lands claim to title, which could adversely affect the Company's title to its properties. While the Company actively consults with all groups which may be adversely affected by the Company's activities, including aboriginal groups, there can be no assurance that satisfactory agreements can be reached.

Additional Funding Requirements

Since the production at the Peace River Project is in its early stage, the Company is still dependant on the equity markets as its major source of operating working capital. From time to time, the Company may require additional financing in order to carry out its acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. There can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favorable terms.

Company Not the Operator of the Peace River, Moberly and deep rights on Monias Projects

The Company is not the operator of the Projects and will have limited or no control over the Projects. More specifically, the Company will have limited or no control over the following: the timing of the drilling and recompleting of wells; the timing and amounts of production; and the development and operating costs.

Issuance of Debt

From time to time, the Company may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. The Company's Articles do not limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Availability of Drilling Equipment and Access Restrictions

CBM exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Changes in Accounting Policies including Initial Adoption

Issued but not Adopted Primary Sources of GAAP

International Financial Reporting Standards ("IFRS")

In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five year transitional period. In February 2008, the AcSB announced that 2011 is the changeover date for publicly-listed companies to use IFRS, replacing Canada's own GAAP. The date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The transition date of January 1, 2011, will require the restatement for comparative purposes of amounts reported by the Company for the year ended April 30, 2011. The Company is currently engaged in the scoping phase of its conversion which involves a high level review of major differences between Canadian GAAP and IFRS, setting a timeline for resources and developing a project plan. This scoping phase is intended to provide direction to the Company's management for the second phase of conversion project and will be disclosed in the Company's annual financial statements and management's discussion and analysis.

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

The CICA issued three new accounting standards in January 2009: Section 1582, "Business Combinations", Section 1601, "Consolidated Financial Statements", and Section 1602, "Non-Controlling Interests". Section 1582 replaces Section 1581, "Business Combinations" and establishes standards for the accounting and business combinations. It provides the Canadian equivalent to *International Financial Reporting Standards IFRS 3*, "Business Combinations". The section applies prospectively to the business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. Sections 1601 and 1602 together replace Section 1600, "Consolidated Financial Statements". Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1601 applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of *International Financial Reporting Standard IAS27*, "Consolidated and Separate Financial Statements" and applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The Company is in process of evaluating the requirements of the new standards.

Investor Relations Activities

Mr. John Proust, a Director of the Company, coordinates investor relations activities.

Change in Directors and Management

During the nine months ended January 31, 2010, the Company announced the resignation of Mr. Winston Purifoy as Director. Mr. Purifoy reduced his directorships in order to pursue his other business interests.

Additional Information and Continuous Disclosure

Additional information on the Company is available through regular filings of press releases and financial statements on SEDAR (www.sedar.com) and on the Company's website at www.canadaenergypartners.com.