Madalena Ventures Inc.

Annual Information Form

Year Ended December 31, 2008

April 23, 2009

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
bbls	Barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
bopd	barrels of oil per day	Bcf	billion cubic feet
NGLs	natural gas liquids	Tcf	trillion cubic feet
STB	stock tank barrels	Gj	gigajoule

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
ARTC	Alberta Royalty Tax Credit
BOE or boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mstboe	1,000 stock tank barrels of oil equivalent
$000's or M$	Thousands of dollars
$mm	Millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
psi	pounds per square inch

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls oil	6.293
feet	Metres	0.305
metres	Feet	3.281
miles	kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471
gigajoules	MMbtu	0.950

In this document, a boe conversion ratio of 6 Mcf = 1 bbl has been used throughout this document. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 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.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, expected levels of activity, budgeted capital expenditures and the method of funding thereof, drilling, completion and tie-in plans, productive capacity of wells, expected royalty rates and changes to the Alberta royalty regime and the possible effect thereof on Madalena may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and estimated production rates, changes in royalty rates and expenses, environmental risks, partner risk and 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, changes in the regulatory and taxation environment, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Madalena's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Madalena believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Madalena can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Madalena operates; the timely receipt of any required regulatory approvals; the ability of Madalena to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Madalena has an interest in to operate the field in a safe, efficient and effective manner; the ability of Madalena to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Madalena to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Madalena operates; and the ability of Madalena to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect Madalena's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at Madalena's website (www.www.madalena-ventures.com.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Company assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NON-GAAP MEASURES

Funds flow from operations and operating netbacks are not recognized measures under GAAP. Management believes that funds flow from operations and operating netbacks are useful supplemental measures as they demonstrate Madalena's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Readers are cautioned, however, that these measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of Madalena's performance. Madalena's method of calculating these measures may differ from other companies and accordingly they may not be comparable to measures used by other companies. For these purposes, Madalena defines funds flow from operations as cash provided by operations before changes in non-cash operating working capital and defines operating netbacks as revenue less royalties and operating expenses.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings:

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" or "**common shares**" means the common shares of Madalena as presently constituted;

"**Company**" or "**Madalena**" means Madalena Ventures Inc., a company created under the laws of the Province of British Columbia, and continued under the laws of the Province of Alberta;

"**Gross**" or "**gross**" means:

(a) in relation to the Company's interest in production and reserves, its "Company gross reserves", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Net**" or "**net**" means:

(d) in relation to the Company's interest in production and reserves, the Company's interest (operating and non-operating) share after deduction of royalties obligations, plus the Company's royalty interest in production or reserves;

(e) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(f) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**NGL**" or "**NGLs**" means natural gas liquid or natural gas liquids;

"**NI 51-101**" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities;

"**NI 51-102**" means National Instrument 51-102 - Continuous Disclosure Obligations;

"**PLA**" means Paddock Lindstrom & Associates Ltd.;

"**PLA Report**" means the report of PLA dated April 17, 2009 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2008;

"**TSXV**" means the TSX Venture Exchange, Inc.; and

"**US dollars**" or "**US $**" means U.S. dollars.

Unless stated otherwise, references to "dollars" or "$" reflect Canadian currency.

MADALENA VENTURES INC.

General

Madalena was created under the laws of the Province of British Columbia on September 14, 2001, on the amalgamation of Madalena Gold Company and Corsair Minerals Inc., as part of a statutory arrangement (the "**Arrangement**") under the former *Issuer Act* (British Columbia) involving Pacific Genesis Technologies, Madalena Gold Company, and Corsair Minerals Inc. On September 30, 2004 Madalena Ventures Inc. amalgamated with a wholly owned subsidiary, RMS Medical Systems Research (B.C.) Ltd., and continued as Madalena Ventures Inc.

On August 22, 2006 the Company completed a further plan of arrangement (the "**2006 Arrangement**") whereby the mineral exploration assets, and marketable securities related to the mineral exploration assets, were transferred to Great Bear Resources Inc. ("**GBR**"), which was formerly a wholly-owned subsidiary of Madalena, with each shareholder of Madalena receiving one common share of GBR for every 15 common shares of Madalena. The purpose of the 2006 Arrangement was to separate the mineral exploration business in GBR so that GBR could carry on the mineral exploration business, and Madalena could focus on its' recently developed oil and gas exploration business. The Company was then continued from the province of British Columbia to the province of Alberta on September 26, 2006.

The Company's Common Shares are listed on the TSXV under the symbol "MVN".

The Company's principal office is located at 200, 441 - 5th Avenue S.W., Calgary, Alberta, T2P 2V1, and the Company's registered office is located at Suite 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Inter-corporate Relationships

The Company owns 100% of the outstanding common shares of Madalena Ventures International Holding Company Inc. (“**MVIHC**”) which in turn owns 100% of the outstanding common shares of Madalena Ventures International Inc (“**MVII**”). Both of these Companies are incorporated under the laws of Barbados. The Company transferred its interest in two seismic exploration agreements in Tunisia to MVII during 2008. The Company's Canadian oil and gas exploration, development and production operations are carried on through a joint venture with Scollard Energy Inc. and Burlington Resources Ltd.

GENERAL DEVELOPMENT OF THE BUSINESS

Madalena is an independent, Canadian-based, international upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. The Company has exploration and production operations in Canada, Tunisia, and South America.

Three Year History

2006

Corporate Matters

In 2006, Madalena focused its efforts on building an international oil and gas exploration and development company. Madalena announced new directors to its board, attracted a new management team and consultants with both domestic and international oil and gas experience, and completed the 2006 Arrangement, which distributed the mineral exploration business to the shareholders.

During fiscal 2006, Madalena raised $27,124,200 to fund its exploration and development opportunities, consisting of (i) a brokered private placement of 12,000,000 common shares at a price of $0.50 per share for total proceeds of $6,000,000, which closed March 2, 2006, (ii) a non-brokered private placement of 1,000,000 units at a price of $1.00 per unit for total proceeds of $1,000,000. Each unit consisted of one common share and one-half of a share purchase warrant, all of which warrants have expired or have been exercised as of the date hereof, and (iii) a brokered private placement, issuing 25,155,250 units at a price of $0.80 per unit for gross proceeds of $20,124,200.

Each unit consisted of one common share and one-half of a share purchase warrant, all of which have expired or have been exercised as of the date hereof.

Canadian Operations

On January 27, 2006, the Company announced an agreement to participate in the drilling of four wells in the Edson area of Alberta, Canada, by paying 25% of drilling, abandonment or completion costs, to earn 12.5% in 12 sections, and on May 8, 2006, the Company announced a second agreement to participate in a six well program in the Brazeau area of Alberta, Canada, by paying 33.335% of drilling, abandonment or completion costs, to earn interests varying between 17% to 24% in 8.5 sections, and an option to participate in two additional sections.

Tunisian Operations

Hammamet Block

On May 23, 2006, the Company entered into a seismic option agreement with Storm Ventures International Inc. ("**Storm**") on the Hammamet offshore exploration block containing over 1.1 million acres in the Pelagian basin offshore Tunisia. The option agreement gives Madalena the right to participate in the drilling of a test well on the block, in exchange for paying 30% of the costs of a 2-D and 3-D seismic program. The option agreement states that if Madalena is to exercise the option it pays 30% of the costs of the test well to earn a 15% working interest and the right to participate in all further development of the block.

Remada Sud Block

On June 8, 2006, the Company entered into a second seismic option agreement with Storm on the Remada Sud onshore exploration block containing over 1.2 million acres in the prospective Ghadames basin of southern Tunisia. The option agreement gives Madalena the right to participate in the drilling of two test wells on the block, in exchange for paying 30% of the costs of a 2-D seismic program. The option agreement states that if Madalena is to exercise the option to drill the first test well it pays 30% of the costs of the test well to earn a 15% working interest in approximately half the block or a 7.5% interest in the entire block as well as the right to participate in all further development of the block. The 2-D seismic program was completed and evaluations with respect to the data were undertaken.

2007

Corporate Matters

In February of 2007, the Company received final listing approval from the TSX Venture Exchange. The Common Shares were listed and posted for trading on Friday, February 16, 2007 under the trading symbol "MVN".

In June of 2007, the Company appointed Mr. James K. Wilson to the Board of Directors. Mr. Wilson brings international oil and gas, public company reporting, and financial reporting experience to the Board of Madalena.

Tunisian Operations

Hammamet Block

In July 2007, the Company announced the commencement of the offshore 3-D seismic program on the Hammanet offshore exploration block in the Pelagian Basin offshore Tunisia.

Remada Sud Block

In July 2007, the Company announced its intention to exercise its option to participate in the drilling of the first test well on the Remada Sud onshore exploration block in southern Tunisia following a review of the newly acquired seismic data.

Argentine Operations

In March 2007, the Company announced that it had been granted approval to operate as a branch in Argentina under the name Madalena Ventures Inc. (Sucursal Argentina), ("**MVISA**"), and in August 2007, the Company announced that it had received governmental approval, from the National Energy Secretariat, registering the Company as an operator in Argentina.

The Cortadera Block

In September 2007, the Company executed a letter of intent with Hidrocarburos del Neuquen Sociedad Anonime ("**HIDENESA**"), the Neuquen Provincial Hydrocarbon Company, and received approval for a work commitment to pursue exploration activities on the Cortadera exploration block in the province of Neuquen, Argentina. In 2007, the joint venture participants in the block were MVISA 70%, HIDENESA 10%, and Estrella Servicios Petroleros S.A. ("**Estrella**") 20%. This joint venture opportunity carried an initial three year exploration term with a work commitment of US $2.5 million in exploration expenditures, including seismic and the drilling of at least one exploration well. In 2007 Madelena and Estrella were proportionately responsible for the costs during the initial exploration term. Upon encountering commercial production on the block a development plan would be implemented with a 12% royalty payable to the province of Neuquen and a concession term of 25 years, with an option to request an additional 10 year extension.

The Curamhuele and Coiron Amargo Blocks

In October 2007, the Company announced that MVISA executed letters of intent with HIDENESA and received approval for a work commitment to pursue exploration activities on two new exploration blocks in the province of Neuquen, Argentina, known as the Curamhuele and Coiron Amargo blocks. Madelena had an initial minimum 70% participating interest in the blocks and HIDENESA has a 10% participating interest. Roch SA had the option to participate for 20%, which they elected to take on February 29, 2008. The joint venture for these new blocks carries an initial three year exploration term with work commitments of US $3.0 million for the Curamhuele block and US $5.0 million for the Coiron Amargo block. Upon encountering commercial production on a block, a development plan will be implemented with a 12% royalty payable to the province of Neuquen and a concession term of 25 years, with an option to request an additional 10 year extension. In addition there is a 1% overriding royalty reserve to a third party on the Curamhuele block.

2008

Corporate Matters

On January 18, 2008 Madalena transferred two seismic exploration agreements it had negotiated with Storm in relation to the Remada Sud and Hammamet exploration blocks, to its wholly owned subsidiary, MVII in Barbados.

On April 4, 2008, Madalena announced the closing of a private placement financing, on a non-brokered basis, through the issuance of 4,375,003 Common Shares at a price of $0.56 per share for gross proceeds of $2.45 million. Proceeds from the private placement were added to the Company's working capital and are to be used to advance the Company's exploration programs in Argentina and assist MVII to fund its exploration program in Tunisia. The Common Shares issued in the private placement were subject to a four-month statutory hold period that commenced on April 4, 2008 and expired on August 5, 2008.

On November 28, 2008, Madalena announced the grant of 1,055,000 options to purchase common shares to Directors, Officers, Employees and Contractors of the Company at an exercise price of $0.105 per common share exercisable for five years, in accordance with the Company's rolling stock option plan approved by the shareholders at the Annual General Meeting in June 2008.

The Company's stock option plan reserves up to 10% (11,174,370) of the outstanding common shares of the Company for issuance under the plan. Options granted to independent directors vest immediately. Options granted to management, consultants, and employees vest equally on the anniversary date of the option over a three year period.

In February of 2009, the Company appointed Mr. Jay Reid to the Board of Directors. Mr. Reid has practiced corporate and securities law since 1990 and has extensive experience with the public issue of securities for oil and gas issuers.

Canadian Operations

During 2008, Madalena maintained its non-operated investments in its Canadian lands by participating in ordinary operations through the operator.

Tunisian Operations

Hammamet Block

In 2008 MVII evaluated the 3D seismic program conducted in 2007 and the potential reactivation of the Tazerka field located on the Hammamet block. MVII determined that economically it would be unable to participate in drilling a test exploration well on the block to earn a 15% working interest and announced the termination of its participation in the Hammamet block in March of 2009.

Remada Sud Block

MVII made significant progress during fiscal 2008 on its exploration opportunities on the Remada Sud block located in the Ghadames Basin in southern Tunisia. On March 31, 2008, MVII announced the commencement of drilling of the first test well (the "**TT2 well**") on the Remada Sud block. On April 25, 2008, MVII announced that the well had reached a total depth of 1500 meters (4,900 feet) in the Ordovician Kasbah Leguine formation, a 60 meter (200 foot) core was cut through the potential reservoir, open hole logs were recorded, and pre-drilling expectations of encountering a 50 meter (165 foot) potential hydrocarbon column in Ordovician quartzites appeared to have been achieved. MVII earned a 15% interest in 600,000 acres on the Remada Sud block in exchange for paying 30% of the cost of drilling the TT2 well, and has the option to pay 30% of the costs of a second test well to earn an additional 15% in the remaining 600,000 acres on the block.

During May, June and July of 2008, the TT2 well was cased to total depth, and various stimulation and production tests were completed. On July 24, 2008, MVII announced that the TT2 well had encountered hydrocarbons in the Ordovician Bir Ben Tartar formation, and had shown indications of hydrocarbons in the Ordovician Jaffara and the Siluran Tannezuft formations. Three intervals in the Bir Ben Tartar formation were tested. The upper two intervals attained combined flow rates of 300 bopd of 45 ºAPI oil and 200 thousand cubic feet of associated gas without stimulation. The lower interval tested small amounts of formation water and was abandoned. Additional testing and evaluation of the other formations took place in August and September of 2008. On September 17, 2008 MVII announced that the TT2 well appeared capable of producing light oil from Ordovician Bir Ben Tartar formation at commercial flow rates similar to those announced on July 24, 2008, and that the additional tests on the other intervals did not result in any significant hydrocarbon inflow. The well was temporarily suspended pending further appraisal of the discovery and submission of a development plan to "ETAP", the Tunisian National Oil Company. On December 29, 2008 MVII announced that it anticipated the TT2 well would be completed and placed on production during Q1, 2009, pending final approvals. On March 16, 2009 Storm received approval from ETAP to conduct a long term production test and on April 20, 2009, MVII announced that after a successful workover on the well was completed in February of 2009, that the well was currently producing approximately 230 bopd of 43 º API oil at a well head pressure of 100 psi with a water cut averaging 2% under the long term production test approved by ETAP. MVII's appraisal plans include 3D seismic surveys, a minimum of one step out well, and long term production tests to determine a phased development plan for submission to ETAP in late 2009.

Argentine Operations

The Curamhuele Block

On June 19, 2008, Madalena announced that equipment was moved to the Curamhuele Block in the Neuquen Province of Argentina (the "**Curamhuele Block**") to evaluate pressures and potential productivity from two existing well bores drilled in the 1990's (Yapai X-1 and Curamhuele X-1) and that additional high pressure wellhead equipment was ordered and access road improvements were made to carry out the evaluation. Further, Madalena announced that that the Yapai X-1 well, operations were under way to allow for unrestricted testing operations and to obtain bottom hole pressures and that 3D seismic programs for the Curamhuele Block were proceeding on schedule.

On July 29, 2008, Madalena announced that operations to evaluate pressures and potential productivity from two existing well bores on the Curamhuele Block were completed with successful results. The previously suspended Yapai X-1 well was tested with positive results over a period of 42 hours incorporating various controlled choke settings of between 9 and 18 millimetres. During this period a total of 14 million cubic feet of gas was flared for an average test rate of 8 million cubic feet per day and varying rates of light oil and condensate production from the Mulichinco formation. The flow rate measured through a nine millimetre choke over a period of 12 hours was 7 million cubic feet per day of gas, an average of 240 bopd of hydrocarbon liquids and 42 bopd of water at a flowing pressure of 2,350 psi. The hydrocarbon liquid gravities tested indicated the presence of high quality hydrocarbons of between 44 ºAPI to 53 ºAPI for oil and condensate. The shut-in wellhead pressure before and after the test was 4,800 psi. The Yapai X-1 well was originally drilled in 1990 to a depth of 3883 meters (12,740 feet)and sidetracked in 1995. The structural trap encountered in this well is not the primary prospect for the Curamhuele Block and represents a significant additional target for the Company's future exploration drilling plans.

On July 29, 2008, Madalena also announced that that following the removal of well plugs from a second well bore located on the Curamhuele Block, the well known as Curamhuele X-1, the well produced approximately 170 barrels of oil from the Lower Agrio formation over five flow periods of between four to six hours conducted during a five day period. The drilling logs for the existing Curamhuele X-1 wellbore indicate that in addition to the oil recovered from this test there is a significant column of additional potential hydrocarbon pay within the Lower Agrio as well as the Mulichinco formation which was successfully tested in the aforementioned Yapai X-1 well bore. Madalena is reviewing the new production information in conjunction with previous log and well data and is preparing plans for completing and testing the previously untested intervals in the Lower Agrio and Mulichinco formations within this well bore. The Curamhuele X-1 well was originally drilled in 1995 to a depth of 2807 meters and deepened to 3444 meters in 1999 and is located approximately 7 kilometres from the Yapai X-1 well bore. The Lower Agrio formation tested in this well is not the primary target for the Curamhuele Block and represents another significant additional target for Madalena’s upcoming exploration drilling plans.

On August 26, 2008, Madalena announced that the Company was in the process of analyzing the testing data from the Curamhuele Block to evaluate the potential development, tie-in and marketing options available, and it was in the process of shooting a 3D seismic program to further delineate the prospectivity of the Curamhuele Block.

On December 29, 2008, Madalena announced that the Company had finished the shooting of an extensive 3D seismic program over the Curamhuele Block to further delineate prospectivity. The seismic program was in processing, with interpretation to be underway during Q1 2009. The Company is also analyzing the testing data from the previously tested Yapai X-1 well and was evaluating the potential development, tie-in and marketing options available for the production from the well.

The Cortadera Block

On July 29, 2008, Madalena announced that 3D seismic programs on the Cortadera Block in the Neuquen Province of Argentina (the "**Cortadera Block**") were underway.

On December 29, 2008, Madalena announced that the Company had finished the shooting of an extensive 3D seismic program over the Cortadera Blocks to further delineate prospectivity. The seismic program was in processing, with interpretation to be underway during Q1 2009.

Madalena also announced on December 29, 2008 that it had finalized negotiations to acquire an additional 20% working interest in the Cortadera Block from its partner in the Neuquen Basin, bringing the Company's holdings to a 90% working interest and operatorship of the Cortadera Block.

The Coiron Amargo Block

On June 19, 2008 Madelena announced that 3D seismic programs for the Coiron Amargo Block were proceeding on schedule. Madelena also announced it had identified several prospective drilling locations that were in the process of being finalized with partners and surveyed.

On July 29, 2008, Madalena announced that 3D seismic programs on the Coiron Amargo Block were continuing.

On November 25, 2008, Madalena announced that it had negotiated a drilling contract for the Company's first exploration well in Argentina on the Coiron Amargo Block, with drilling to commence in January 2009 on a prospective feature identified by 3D seismic.

On December 29, 2008, Madalena announced that the drilling rig contracted to drill the Company's CAN X-2 exploratory well on the Coiron Amargo Block in the Province of Neuquen, Argentina was moved onto the drill site, and drilling operations were to commence during the first week of January, 2009. CAN X-2 is situated on a 3D defined drilling anomaly located less than one kilometre from the producing Loma Jarillosa pool located directly west of the prospect.

On February 5, 2009 Madalena announced that CAN X-2 well was drilled and cased to the total depth of 3353 meters (11,001 feet). The Company also announced that it had identified two separate zones with hydrocarbon potential and it was moving completion equipment onsite to perforate and adequately test the potential productivity from the two zones.

On February 24, 2009, Madalena announced that the deeper of the two formations, the Sierras Blancas formation, was initially perforated and tested for a 48 hour period at varying choke sizes. During this 48 hour period the CAN X-2 well flowed approximately 1000 bbls of oil with a 0-1% water cut and without requiring artificial stimulation. At the end of the 48-hour period, the well appeared to stabilize at a rate of approximately 400 bopd with an oil gravity of 38 ºAPI. The Sierras Blancas formation is the primary zone currently producing from offsetting blocks which have been developed using both vertical and horizontal drilling. The CAN-X2 well represents the first well drilled into a new Sierras Blancas oil pool discovery on the Block and was drilled vertically to enable the Company to evaluate all potential hydrocarbon zones and clearly identify the oil water contact for future horizontal drilling application. A number of the Sierras Blancas producing oil wells in the offsetting blocks have approximately 15 to 20 meters of oil pay over water and often require fracture stimulation to enhance productivity. Madalena is pleased to report that the CAN-X2 well has encountered approximately 20 meters of oil pay over water and will not require fracture stimulation due to the presence of an excellent porosity/permeability system at the top of the CAN-X2 reservoir as evidenced by log results and the significant flowing test rates and pressures. Upon completion of testing operations on the Sierras Blancas formation the Company will move uphole to test and evaluate the potential productivity of a second formation with hydrocarbon potential. Additional information will be disseminated upon completion of the testing results on the two formations.

On March 5, 2009, Madalena confirmed the production tests released on February 24, 2009, and announced that a second potential zone in the well bore, the Vaca Muerta formation, had been tested yielding no hydrocarbon inflows after initial perforation and acid stimulation. Madalena elected not to fracture stimulate the Vaca Muerta formation but believes that there is significant future potential on the block for future Vaca Merta exploration and development. Madalena also announced that it intends to place the CAN-X2 well on production from the Sierras Blancas formation as soon as possible and that the production from this formation and the inventory of drillable locations identified from the 3D seismic surveys provide a number of targets for additional wells on the block.

PRINCIPAL PROPERTIES

Madalena's strategy is to create value through the generation of a balanced portfolio of high quality oil and gas assets in proven hydrocarbon areas characterized by competitive fiscal terms and significant development potential.

Principal Properties

Canada (Brazeau and Edson Areas of Alberta)

All of Madalena's production for 2008 comes from non-operated properties in the Brazeau and Edson Areas of Alberta. The Brazeau area of Alberta is located south of Drayton Valley and the Edson area is located approximately 100 miles west of Edmonton.

Madalena has working interests of between 20% and 25% in six non-operated wells in Brazeau, Madalena obtains natural gas and natural gas liquids from its interests in four gross gas wells producing from the Rock Creek, Notikewin, Shunda and Fernie formations, and light oil production from one gross oil well in the Peco formation. One gas well is shut in.

Madalena has a 12.5% working interest in one producing gas well and one shut in gas well in the Edson area of Alberta which produces from the Rock Creek formation.

Madalena’s share of production from the Brazeau and Edson properties averaged 24.4 bopd for the fourth quarter of 2008. The PLA Report attributes proved plus probable reserves of 101.1 MBOE to Madalena’s working interests in Brazeau and Edson. The PLA Report attributes proved reserves of 70.3 MBOE to Madalena’s working interests in Brazeau and Edson.

Future development plans by the operator in Brazeau include the completion of three new zones in a producing gas well, and the drilling of a new well to which reserves have been assigned in the Rock Creek and Notikewan zones. Future development plans by the operator of the Edson properties include completion of one gas well which was not completed as planned in 2008.

Tunisia (Remada Sud and Hammamet)

In 2006, Madalena entered into seismic option agreements with Storm (the operator of the properties) for the onshore Remada Sud and offshore Hammamet exploration blocks in Tunisia. The seismic option agreements gave Madalena the right to participate in the drilling of two exploration wells on the Remada Sud block, and one exploration well on the Hammamet block in exchange for Madalena paying for 30% of the costs of 2D and 3D seismic acquisition and evaluation programs on the blocks. The seismic option agreements were transferred to MVII in January of 2008.

The Remada Sud exploration block is located in the Ghadames basin in the southern portion of Tunisia along the border of Libya. The exploration block covers 1.2 million acres of exploration property. The 2D seismic acquisition program was completed in Remada Sud during the second quarter 2007 providing further delineation of structures identified by the 2D seismic data shot during 2005. In June of 2007 the Company announced its intention to participate in the first test well and in January of 2008 the Company formally exercised its election to participate in the first test well earning a 15% working interest in approximately half of the block (600,000 acres) and the option to participate in a second test well on the block. The drilling of the TT-2 well in Remada Sud commenced on March 28, 2008 on a large structure with an areal extent of approximately 70 square kilometres. Target depth was reached at 1500 meters (4,900 feet) in the Ordovician Kasbah Leguine formation on April 16, 2008, and a 60 meter (200 foot) core was cut through the potential reservoir. Upon initial review of the core, the pre-drilling expectation of encountering a 50 meter (165 foot) potential hydrocarbon column in Ordovician quartzites appeared to have been achieved. The well was cased to total depth, the core underwent extensive core analysis, and various stimulation and production tests were completed on three potential hydrocarbon formations in the well bore. On July 24 2008, Madalena announced that two tested intervals had attained combined flow rates of 300 bopd of 45 ºAPI oil and 200 thousand cubic feet of associated gas without stimulation. The Company announced on September 17, 2008 that the TT2 well appears capable of producing light oil at commercial production rates. The well was temporarily suspended for the remainder of 2008 pending further appraisal of the discovery and submission of a development plan to ETAP, the Tunisian National Oil Company. In February of 2009 the Company participated in a work-over on the well and in March of 2009 the operator of the well received approval from ETAP to conduct a long term production test. In April of 2009 the Company announced that the well was currently producing approximately 230 bopd of 43 º API oil at a well head pressure of 100 psi with a water cut averaging 2% under the long term production test approved by ETAP. The operators future appraisal plans for the area include a 3D seismic survey, one step out well, long term production tests, and the preparation of a phased development plan for submission to ETAP in late 2009.

The Hammamet exploration block is located in shallow waters off the north eastern tip of Tunisia in the Gulf of Hammament in the Mediterranean Sea. The block includes approximately 1.1 million acres of exploration property. 2-D and 3-D seismic programs were completed in the third quarter 2007 to highlight existing leads and prospects in the offshore Hammamet area. In 2008 MVII evaluated the 3D seismic program conducted in 2007 and the potential reactivation of the Tazerka field located on the Hammamet block. MVII determined that economically it would be unable to participate in drilling a test exploration well on the block to earn a 15% working interest and announced the termination of its participation in the Hammamet block in March of 2009.

The PLA Report attributes proved plus probable reserves of 341 MBOE to Madalena's working interests in Remada Sud. The PLA Report attributes proved reserves of 145.7 MBOE to Madalena's working interests in Remada Sud. No reserves have been assigned in connection with the Hammamet property. The Company and its operator have the right to explore and appraise the Tunisian assets but do not have the right to produce from the properties until such time as reserves are determined to be commercial. The appraisal plan proposed by the operator of Remada Sud is intended to determine commerciality. Exploration, appraisal and development of crude oil and natural gas reserves is speculative and involves a significant degree of risk. There is no guarantee that exploration or appraisal of the Tunisian blocks will lead to a commercial discovery or, if there is a discovery, that the Company will be able to realize such reserves. See "*Risk Factors*".

Argentina (Cortadera, Curamhuele, and Coiron Amargo)

In November of 2007, Madalena executed joint venture agreements with HIDENESA on three concessions granted by the Province of Neuquen in Argentina, South America. The three blocks, Cortadera, Curamhuele, and Coiron Amargo are located in the Neuquen producing basin in the Province of Neuquen and contain approximately 278,000 acres of exploration area.

The Cortadera block covers an area of approximately 124,000 acres and is situated along the western thrust belt of the Neuquen basin in the middle portion of the province of Nuequen, approximately 700 miles south and west of Buenos Aires. Madalena has a 90% interest in the block which carries a three year exploration term with a work commitment of US $2.5 million which includes exploration costs, seismic and the drilling of at least one exploration well. At December 31, 2008 Madalena had substantially completed its commitments for exploration costs and seismic surveys at Cortadera. The remaining commitment on the property involves drilling one exploration well in the amount of US $1.1 million. Madalena anticipates that the cost of drilling an exploration well on the Cortadera block will exceed the commitment amount. Madalena is currently in the process of evaluating the seismic surveys. Madalena pays 100% of the costs during the exploration phase. If reserves are discovered in commercial quantities production will be subject to a 12% royalty payable to the province of Neuquen. HIDENESA is responsible for its 10% share of the costs incurred in the development and production phase.

The Curamhuele block covers an area of approximately 56,000 acres and is situated along the east side of a north south trending fault in the middle portion of the province of Nuequen, approximately 650 miles south and west of Buenos Aires and approximately 50 miles north of the Cortadera block. Madalena has a 70% interest in the block which carries a three year exploration term with a work commitment of $3.0 million US $ which includes exploration costs, seismic and the drilling of at least one exploration well. At December 31, 2008 Madalena had substantially completed its commitments for exploration costs and seismic surveys at Curamhuele. The remaining commitment on the property involves drilling at least one exploration well in the amount of US $1,131,00. Madalena anticipates that the cost of drilling an exploration well on the block will exceed the commitment amount. During 2008 Madalena evaluated two well bores drilled in the 1990's which were on the Curamhuele block when it was granted to the Company in 2007. The test results as outlined above under "General Development of the Business" were positive and provided Madalena with valuable information for evaluation of potential drilling locations on the block. Madalena is currently evaluating the seismic surveys completed on the block and the test results from the two well bores in order to evaluate potential development, tie-in and marketing options for the two well bores, as well as potential drilling locations for its first exploration well on the block. Madalena and its 20% working interest partner, Roch, pay 100% of the costs during the exploration phase. If reserves are discovered in commercial quantities production will be subject to a 12% royalty payable to the province of Neuquen. HIDENESA is responsible for its 10% share of the costs incurred in the development and production phase.

The Coiron Amargo block covers an area of approximately 100,000 acres and is situated along the east side of the Neuquen block, approximately 650 miles southwest of Buenos Aires and approximately 75 miles east of the Cortadera block. Madalena has a 70% interest in the block which carries a three year exploration term with a work commitment of US $5.0 million which includes exploration costs, seismic and the drilling of at least one exploration well. At December 31, 2008 Madalena had substantially completed its commitments for exploration costs and seismic surveys at Coiron Amargo. The remaining commitment on the property involves drilling at least one exploration well in the amount of US $3,396,000. Madalena anticipates that the cost of drilling the CAN-X2 well described below will fulfil it’s commitments on the Coiron Amargo block. Madalena and its 20% working interest partner, Roch, pay 100% of the costs during the exploration phase. If reserves are discovered in commercial quantities production will be subject to a 12 royalty payable to the province of Neuquen. HIDENESA is responsible for its 10% share of the costs incurred in the development and production phase.

On November 25, 2008, Madalena announced that it had negotiated a drilling contract for the Company's first exploration well in Argentina on the Coiron Amargo Block, with drilling to commence in January 2009 on a prospective feature identified by 3D seismic that was undertaken during 2008. On February 2, 2009 the CAN X-2 well was drilled and cased to a total depth of 3353 meters and revealed two separate zones with hydrocarbon potential. On February 24, 2009, Madalena announced that the deeper of the two formations, the Sierras Blancas formation, showed favourable testing results. The Sierras Blancas formation is the primary zone currently producing from offsetting blocks which have been developed using both vertical and horizontal drilling. The CAN-X2 well represents the first well drilled into a new Sierras Blancas oil pool discovery on the Coiron Amargo Block and was drilled vertically to enable the Company to evaluate all potential hydrocarbon zones and clearly identify the oil water contact for future horizontal drilling application. A number of the Sierras Blancas producing oil wells in the offsetting blocks have approximately 15 to 20 meters of oil pay over water and often require fracture stimulation to enhance productivity. Madalena is pleased to report that the CAN-X2 well has encountered approximately 20 meters of oil pay over water and will not require fracture stimulation due to the presence of an excellent porosity/permeability system at the top of the CAN-X2 reservoir as evidenced by log results and the significant flowing test rates and pressures. Upon completion of testing operations on the Sierras Blancas formation the Company will move uphole to test and evaluate the potential productivity of a second formation with hydrocarbon potential. On March 5, 2009, Madalena confirmed the production tests released on February 24, 2009, and announced that a second potential zone in the well bore, the Vaca Muerta formation, had been tested yielding no hydrocarbon inflows after initial perforation and acid stimulation. Madalena elected not to fracture stimulate the Vaca Muerta formation but believes that there is significant future potential on the block for future Vaca Merta exploration and development. Madalena also announced that it intends to place the CAN-X2 well on production from the Sierras Blancas formation as soon as possible and that the production from this formation and the inventory of drillable locations identified from the 3D seismic surveys provide a number of targets for additional wells on the block.

No reserves have been assigned to the Argentinean blocks given their early stage of development. The Company and its operators have the right to explore and appraise the Argentine blocks but do not have the right to produce from the properties until such time as reserves are determined to be commercial. Exploration, appraisal and development of crude oil and natural gas reserves is speculative and involves a significant degree of risk. There is no guarantee that exploration or appraisal of the Argentine blocks will lead to a commercial discovery or, if there is a discovery, that the Company will be able to realize such reserves. See "*Risk Factors*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated April 17, 2009. The effective date of the statement is December 31, 2008 and the preparation date of the statement is April 17, 2009.

Disclosure of Reserves Data and Other Information

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by PLA of the Reserves in association with Madalena's assets and has an effective date of December 31, 2008. The PLA Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The Reserves Data summarizes the oil, liquids and natural gas reserves associated with Madalena's assets and properties and the net present values of future net revenue for these Reserves using forecast prices and costs as at December 31, 2008. The Reserves Data conforms with the requirements of NI 51-101. Madalena engaged PLA to provide evaluations of Proved Reserves and Proved plus Probable Reserves.

All evaluations of future revenue are stated after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the Reserves associated with Madalena's assets and properties. There is no assurance that the forecast price and cost assumptions contained in the PLA Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to the following tables. The recovery and reserves estimates for Madalena's assets and properties described herein are estimates only and there is no guarantee that the estimated Reserves will be recovered. The actual Reserves for Madalena's assets and properties may be greater or less than those calculated.

The Report of Management and Directors on Oil and Gas Disclosure (on Form 51-101F3) and the Report on Reserves Data by PLA (on Form 51-101F2) are included in this AIF. See "Form 51-101F2 - Report on Reserves Data by PLA Petroleum Consultants Ltd." and, "Form 51-101F3 - Report of Management and Directors on Oil and Gas Disclosure" attached hereto as Schedules A and B, respectively.

Summary of Oil and Gas Reserves
and Net Present Values of Future Net Revenue
At December 31, 2008

Forecast Prices and Costs

The following tables provide a summary of the Company's oil and gas reserves and net present value of future net revenue at December 31, 2008 using forecast prices and costs in the aggregate (combined table) and by each Country. Amounts shown for Tunisia are in US $, amounts shown for Canada are in Canadian dollars, and amounts shown in the combined table are in Canadian dollars converted at a rate of 1.2246 Canadian dollars for each US dollar which is the Bank of Canada conversion rate at December 31, 2008.

Combined

	Reserves[1]									
	Natural Gas				NGL		Light/Medium Crude Oil		Oil Equivalent[2]	
	Assoc. & Non-Assoc.		Solution							
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Proved										
Developed Producing	123.6	109.8	18.1	14.8	5.4	3.4	15.0	12.1	44.1	36.2
Developed Non-Producing	32.5	29.7	0.0	0.0	0.9	0.5	0.0	0.0	6.3	5.5
Undeveloped	168.8	152.0	0.0	0.0	5.0	3.2	145.7	145.7	178.9	174.3
Total Proved	324.9	291.5	18.1	14.8	11.3	7.1	160.7	157.8	229.3	216.0
Probable	155.6	140.2	5.2	4.3	5.6	3.4	199.7	198.6	232.0	226.1
Total Proved Plus Probable	480.5	431.7	23.3	19.1	16.9	10.5	360.4	356.4	461.3	442.1
Possible	-	-	-	-	-	-	239.9	239.9	239.9	239.9
Total Proved Plus Probable Plus Possible	480.5	431.7	23.3	19.1	16.9	10.5	600.3	596.3	701.2	682.0

Notes:
(1) Numbers in this table are subject to round off error.
(2) Natural gas is converted to boe's at a ratio of six thousand standard cubic feet to one barrel of oil.

Canada

	Reserves[1]									
	Natural Gas				NGL		Light/Medium Crude Oil		Oil Equivalent[2]	
	Assoc & Non Assoc.		Solution							
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Proved										
Developed Producing	123.6	109.8	18.1	14.8	5.4	3.3	15.1	12.1	44.1	36.2
Developed Non-Producing	32.5	29.7	0.0	0.0	0.9	0.5	0.0	0.0	6.3	5.5
Undeveloped	168.8	152.0	0.0	0.0	5.0	3.2	0.0	0.0	33.2	28.6
Total Proved	324.9	291.5	18.1	14.8	11.3	7.1	15.1	12.1	83.6	70.3
Probable	155.6	140.2	5.2	4.3	5.6	3.4	4.4	3.3	36.7	30.8
Total Proved Plus Probable	480.5	431.7	23.3	19.1	16.9	10.5	19.5	15.4	120.3	101.1
Possible	-	-	-	-	-	-	-	-	-	-
Total Proved Plus Probable Plus Possible	480.5	431.7	23.3	19.1	16.9	10.5	19.5	15.4	120.3	101.1

Notes:
(1) Numbers in this table are subject to round off error.
(2) Natural gas is converted to boe's at a ratio of six thousand standard cubic feet to one barrel of oil.

Tunisa	**Reserves(1)**									
	Natural Gas				**NGL**		**Light/Medium Crude Oil**		**Oil Equivalent(2)**	
	Assoc & Non Assoc.		**Solution**							
Reserves Category	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Proved										
Developed Producing	-	-	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	145.7	145.7	145.7	145.7
Total Proved	-	-	-	-	-	-	145.7	145.7	145.7	145.7
Probable	-	-	-	-	-	-	195.3	195.3	195.3	195.3
Total Proved Plus Probable	-	-	-	-	-	-	341.0	341.0	341.0	341.0
Possible	-	-	-	-	-	-	239.9	239.9	239.9	239.9
Total Proved Plus Probable Plus Possible	-	-	-	-	-	-	580.9	580.9	580.9	580.9

Notes:

(1) Numbers in this table are subject to round off error.

(2) Natural gas is converted to boe's at a ratio of six thousand standard cubic feet to one barrel of oil.

Combined (CDN $'s)

	Net Present Values of Future Net Revenue					
	Before and after Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year
Reserves Category	**0% CDN M$**	**5% CDN M$**	**10% CDN M$**	**15% CDN M$**	**20% CDN M$**	**$/boe**
Proved						
Producing	1,354.7	1,065.8	879.4	751.7	659.6	24.27
Developed Non-Producing	125.9	105.4	89.5	77.0	67.0	16.36
Undeveloped	3,760.7	2,245.2	1,159.8	376.5	-191.7	6.66
Total Proved	5,241.3	3,416.4	2,128.7	1,205.2	534.9	9.86
Probable	12,179.3	8,986.4	6,760.2	5,155.7	3,.972.0	29.90
Total Proved Plus Probable	17,420.6	12,402.8	8,888.9	6,360.9	4,506.9	20.11
Possible	11,009.3	7,900.6	5,635.0	4,017.4	2,867.1	23.49
Total Proved Plus Probable Plus Possible	28,429.9	20,303.4	14,523.9	10,378.3	7,374.0	21.30

Canada (CDN $'s)

	Net Present Values of Future Net Revenue					
	Before and after Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year
Reserves Category	**0% CDN M$**	**5% CDN M$**	**10% CDN M$**	**15% CDN M$**	**20% CDN M$**	**$/boe**
Proved						
Producing	1,354.7	1,065.8	879.4	751.7	659.6	24.27
Developed Non-Producing	125.9	105.4	89.5	77.0	67.0	16.36
Undeveloped	638.7	458.6	333.3	243.4	176.9	11.67
Total Proved	2,119.3	1,629.8	1,302.3	1.072.1	903.5	18.53
Probable	1,419.8	875.5	590.8	426.8	324.3	19.18
Total Proved Plus Probable	3,539.1	2,505.3	1,893.1	1,489.9	1227.8	18.73
Possible	-	-	-	-	-	-
Total Proved Plus Probable Plus Possible	3,539.1	2,505.3	1,893.1	1,489.9	1,227.8	18.73

Tunisia (US $'s)

	Net Present Values of Future Net Revenue					
	Before and after Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year
Reserves Category	**0% US M$**	**5% US M$**	**10% US M$**	**15% US M$**	**20% US M$**	**$/boe**
Proved						
Producing	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	2,549.5	1,458.9	674.8	108.7	-301.0	4.63
Total Proved	2,549.5	1,458.9	674.8	108.7	-301.0	4.63
Probable	8,786.1	6,623.3	5,037.9	3,861.6	2,978.7	25.79
Total Proved Plus Probable	11,335.6	8,082.2	5,712.7	3,970.3	2,677.7	16.75
Possible	8,990.1	6,451.6	4,601.6	3,280.6	2,341.3	19.18
Total Proved Plus Probable Plus Possible	20,325.7	14,533.8	10,314.3	7,250.8	5,019.0	17.76

Total Future Net Revenue
(Undiscounted)
At December 31, 2008

Forecast Prices and Costs

The following tables provide a summary of the Company's total future net revenue (undiscounted) at December 31, 2008 using forecast prices and costs in the aggregate (combined table) and by each Country. Amounts shown for Tunisia are in US dollars, amounts shown for Canada are in Canadian dollars, and amounts shown in the combined table are in Canadian dollars converted at a rate of 1.2246 Canadian dollars for each US dollar. **[NTD: Same comment re: exchange rate.]**

Combined (CDN $'s)

Reserves Category	Revenue CDN M$	Royalties (Includes ARTC) CDN M$	Operating Costs CDN M$	Develop-ment Costs CDN M$	Well Abandonment and Reclamation Costs CDN M$	Future Net Revenue Before Income Taxes CDN M$	Income Taxes CDN M$	Future Net Revenue After Income Taxes CDN M$
Total Proved Reserves	20,045.8	869.4	3,840.7	8,661.3	1,433.0	5,241.4	-	5,241.4
Total Proved Plus Probable Reserves	44,025.8	1,324.7	8,273.1	13,714.1	3,293.2	17,420.7	-	17,420.7
Total Proved Plus Probable Plus Possible Reserves	72,174.1	1,324.7	15,373.3	20,275.5	6,770.7	28,429.9	-	28,429.9

Canada (CDN $'s)

Reserves Category	Revenue CDN M$	Royalties (Includes ARTC) CDN M$	Operating Costs CDN M$	Develop-ment Costs CDN M$	Well Abandonment and Reclamation Costs CDN M$	Future Net Revenue Before Income Taxes CDN M$	Income Taxes CDN M$	Future Net Revenue After Income Taxes CDN M$
Total Proved Reserves	5,504.3	869.4	1,984.9	441.2	89.5	2,119.3	-	2,119.3
Total Proved Plus Probable Reserves	8,275.3	1,324.7	2,812.1	503.8	95.6	3,539.1	-	3,539.1
Total Proved Plus Probable Plus Possible Reserves	8,275.3	1,324.7	2,812.1	503.8	95.6	3,539.1	-	3,539.1

Tunisia (US $'s)

Reserves Category	Revenue US M$	Royalties (Includes ARTC) US M$	Operating Costs US M$	Develop-ment Costs US M$	Well Abandonment and Reclamation Costs US M$	Future Net Revenue Before Income Taxes US M$	Income Taxes US M$	Future Net Revenue After Income Taxes US M$
Total Proved Reserves	11,874.5	-	1,515.5	6,712.4	1,097.1	2,549.5	-	2,549.5
Total Proved Plus Probable Reserves	29,193.6	-	4,459.5	10,787.4	2,611.1	11,335.6	-	11,335.6
Total Proved Plus Probable Plus Possible Reserves	52,179.4	-	10,257.4	16,145.5	5,450.8	20,325.7	-	20,325.7

Future Net Revenue
by Production Group
at December 31, 2008

Forecast Prices And Costs

Future Net Revenue Before Income Taxes (discounted at 10%/year)

The following tables provide a summary of the Company's future net revenue by production group at December 31, 2008 using forecast prices and costs in the aggregate (combined table) and by each Country. Amounts shown in the Tunisia table are in US dollars, amounts shown in the Canada table are in Canadian dollars, and amounts shown in the combined table are in Canadian dollars applying a year end conversion rate of 1.2246 Canadian dollars which is the Bank of Canada conversion rate at December 31, 2008.

Combined (CDN $'s)

Reserves Category	Production Group	CDN M$	$/bbl or $/Mcf
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	1,359.7	8.62
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	769.0	2.64
	Total Combined Proved	**2,128.7**	**9.86**
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	7,639.2	21.43
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,249.7	2.89
	Total Combined Proved plus Probable	**8,888.9**	**20.11**
Proved plus Probable Plus Possible Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	13,274.2	22.26
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,249.7	2.89
	Total Combined Proved plus Probable Plus Possible	**14,523.9**	**21.30**

Canada (CDN $'s)

Reserves Category	Production Group	CDN M$	$bbl or $Mcf
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	533.3	43.94
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	769.0	2.64
	Total Canada Proved	**1,302.3**	**18.53**
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	643.4	41.65
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,249.7	2.89
	Total Canada Proved plus Probable	**1.893.1**	**18.73**
Proved plus Probable Plus Possible Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	643.4	41.65
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	1,249.7	2.89
	Total Canada Proved plus Probable Plus Possible	**1,893.1**	**18.73**

<u>Tunisia (US $'s)</u>

Reserves Category	Production Group	US M$	$/bbl or $/Mcf
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	674.8	4.63
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	-	-
	Total Tunisia Proved	**<u>674.8</u>**	**4.63**
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	5,712.7	16.75
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	-	-
	Total Tunisia Proved plus Probable	**<u>5,712.7</u>**	**16.75**
Proved plus Probable Plus Possible Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	10,314.2	17.76
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	-	-
	Total Tunisia Proved plus Probable Plus Possible	**10,314.2**	**17.76**

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the PLA Report are based on the definitions and guidelines contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

Reserves are 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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(c) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by PLA in the PLA Report were PLA's forecasts, as at December 31, 2008, as follows:

Summary of Pricing And Inflation Rate Assumptions at December 31, 2008

Forecast Prices And Costs

PLA Petroleum Consultants Natural Gas Price Forecast Effective January 1, 2009

		Alliance							
		Spot							
Year	AECO-C Spot Then Current (CDN$/MMbtu)	Then Constant 2008 ($/MMbtu)	Then Current ($/MMbtu)	ARP ($/MMbtu)	Aggregator ($/MMbtu)	Alliance ($/MMbtu)	Inflation Rates [(1)] (%/year)	Exchange Rate [(2)] ($US/$CDN)
2009	7.24	6.96	6.96	6.96	6.96	6.71	2	1
2010	7.90	7.62	7.62	7.62	7.62	7.36	2	1
2011	8.26	7.97	7.97	7.97	7.97	7.71	2	1
2012	8.60	8.30	8.30	8.30	8.30	8.03	2	1
2013	9.13	8.83	8.83	8.83	8.83	8.56	2	1
2014	9.45	9.14	9.14	9.14	9.14	8.86	2	1
2015	9.64	9.32	9.32	9.32	9.32	9.04	2	1
2016	9.83	9.51	9.51	9.51	9.51	9.22	2	1
2017	10.03	9.70	9.70	9.70	9.70	9.41	2	1
2018	10.23	9.89	9.89	9.89	9.89	9.60	2	1
2019	10.43	10.09	10.09	10.09	10.90	9.79	2	1
2020	10.64	10.29	10.29	10.29	10.29	9.98	2	1
2021	10.86	10.50	10.50	10.50	10.50	10.18	2	1
2022	11.07	10.71	10.71	10.71	10.71	10.39	2	1
2023	11.29	10.92	10.92	10.92	10.92	10.59	2	1
2024	11.52	11.14	11.14	11.14	11.14	10.81	2	1
2025	11.75	11.37	11.37	11.37	11.37	11.02	2	1
2026	11.98	11.59	11.59	11.59	11.59	11.24	2	1

PLA Petroleum Consultants Crude Oil and Natural Gas Liquids Price Forecast Effective January 1, 2009

Year	Inflation Rates [(1)] (%/year)	Exchange Rate [(2)] ($US/$CDN)	WTI @ Cushing $CDN/bbl	Edmonton Reference Price $CDN/bbl	Condensate $CDN/bbl	Butane $CDN/bbl	Propane $CDN/bbl	[(3)] UK Brent $US/bbl
2009	2	1	71.43	70.18	70.88	56.14	42.11	51.73
2010	2	1	78.49	77.21	77.99	61.77	46.33	61.37
2011	2	1	85.23	83.93	84.77	67.14	50.36	67.45
2012	2	1	91.67	90.34	91.24	72.27	54.20	77.47
2013	2	1	100.00	98.65	99.63	78.92	59.19	89.84
2014	2	1	102.00	100.62	101.63	80.50	60.37	91.64
2015	2	1	104.04	102.63	103.66	82.11	61.58	93.47
2016	2	1	106.12	104.68	105.73	83.75	62.81	95.34
2017	2	1	108.24	106.78	107.85	85.42	64.07	97.25
2018	2	1	110.41	108.91	110.00	87.13	65.35	99.19
2019	2	1	112.62	111.09	112.20	88.87	66.66	101.18
2020	2	1	114.87	113.31	114.45	90.65	67.99	-
2021	2	1	117.17	115.58	116.74	92.46	69.35	-
2022	2	1	119.51	117.89	119.07	94.31	70.74	-
2023	2	1	121.90	120.25	121.45	96.20	72.15	-
2024	2	1	124.34	122.66	123.88	98.12	73.59	-
2025	2	1	126.82	125.11	126.36	100.09	75.06	-
2026	2	1	129.36	127.61	128.89	102.09	76.57	-

Notes:

(1) Inflation rates for forecasting pricing and costs.
(2) Exchange rates used to benchmark reference prices in this table.

(3) Tunisia calculations used UK Brent forecast pricing in US $. Net present values were then converted to CDN $ for combined values using an exchange rate of 1.2246 Canadian dollars for each US dollar which is the Bank of Canada conversion rate at December 31, 2008.

Weighted average historical prices realized by the Company for year ended December 31, 2008 were $8.88 for natural gas, $101.70 for crude oil, and $86.37 for natural gas liquids.

4. Estimated future abandonment costs related to a working interest have been taken into account by PLA in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment of any facilities.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. The extent and character of all factual data supplied to PLA were accepted by PLA as represented. No field inspection was conducted.

7. The impact of the optional Transitional Royalty Rate ("**TRR**") (announced by the Alberta Government on November 19, 2008) was considered in forecasts of future drilling in Alberta and taken into account in the above calculations of future net revenue. In the calculation of future net revenue the Corporation is assumed to opt for TRR on new wells where justified by a comparison of economics under TRR and the NRF. The effects of the short term incentive program announced by the Government of Alberta on March 3, 2009 were not included or considered in the calculation of reserves and future net revenue. See "Industry Conditions – Provincial Royalties and Incentives – Alberta".

Reconciliation of Gross Reserves by Principal Product Type

The following table summarizes the changes in reserves from December 31, 2007 to December 31, 2008:

Forecast Prices And Costs

Combined	Light & Medium Crude Oil			Associated & Non- Associated Gas		
FACTORS	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	23.0	7.0	30.0	361.0	154.0	515.0
Technical Revisions	-4.7	-2.8	-7.4	-2.1	1.6	-0.5
Discovery	24.3	14.0	38.2	-	-	-
Extension	121.4	181.4	302.8	-	-	-
Improved Recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-3.2	-	-3.2	-34.1	-	-34.1
December 31, 2008	160.8	199.6	360.4	324.8	155.6	480.4

Canada	Light & Medium Crude Oil			Associated & Non- Associated Gas		
FACTORS	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	23.0	7.0	30.0	361.0	154.0	515.0
Technical Revisions	-4.7	-2.7	-7.4	-2.1	1.6	-0.5
Discovery	-	-	-	-	-	-
Extension	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-3.2	-	-3.2	-34.1	-	-34.1
December 31, 2008	15.1	4.3	19.4	324.8	155.6	480.4

Tunisia	Light & Medium Crude Oil			Associated & Non- Associated Gas		
FACTORS	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-
Discovery	24.3	13.9	38.2	-	-	-
Extension	121.4	181.4	302.8	-	-	-
Improved Recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	-	-	-
December 31, 2008	145.7	195.3	341.0	-	-	-

Historical Undeveloped Reserves – Forecast Prices and Costs

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Company's assets for the years ended December 31, 2008, 2007 and 2006 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Combined						
Prior to 2006	-	-	-	-	-	-
2006	-	-	87.0	87.0	4.0	4.0
2007	-	-	-	-	-	-
2008	145.7	145.7	75.7	152.0	1.9	3.2
Canada						
Prior to 2006	-	-	-	-	-	-
2006	-	-	87.0	87.0	4.0	4.0
2007	-	-	-	-	-	-
2008	-	-	75.7	152.0	1.9	3.0
Tunisia						
2006	-	-	-	-	-	-
2007	-	-	-	-	-	-
2008	145.7	145.7	-	-	-	-

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Combined						
Prior 2006	-	-	-	-	-	-
2006	-	-	35.0	35.0	2.0	2.0
2007	-	-	-	-	-	-
2008	195.3	195.3	-	26.1	-	1.1
Canada						
Prior 2006	-	-	-	-	-	-
2006	-	-	35.0	35.0	2.0	2.0
2007	-	-	-	-	-	-
2008	-	-	-	26.1	-	1.1
Tunisia						
Prior 2006	-	-	-	-	-	-
2006	-	-	-	-	-	-
2007	-	-	-	-	-	-
2008	195.3	195.3	-	-	-	-

Proved Undeveloped Reserves

The Company generally attributes proved undeveloped reserves under the following categories:

1. Wells which are budgeted and scheduled to be drilled in the near future and are located between existing wells such that there is a high degree of certainty that the reservoir is present and producible in these locations.

2. Enhanced recovery recognition on pools which the Company expects to be put under EOR within the next year and/or incremental recovery from recently implemented EOR projects.

The Company does not carry proved undeveloped reserves for long periods of time unless there is a good reason (such as the above) for not putting these reserves on production in the short term. In fact, where there is sufficient economic justification, the Company will often take steps to accelerate production from gas caps and secondary zones. These steps involve early gas cap blowdown when it does not significantly impact oil recovery and dually completing or twinning wells for secondary zones.

Probable Undeveloped Reserves

Probable undeveloped reserves are, for the most part, attributed to step-out drilling locations, re-completion and tie-ins that are anticipated to proceed in the near term but do not meet the required confidence factor to be booked as proved.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires judgment and making decisions based on available geological, geophysical, engineering and economic data. Estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, geological evaluation, engineering data, prices and economic conditions. The Reserves associated with the Madalena assets have been evaluated by PLA, an independent engineering firm. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the Reserves.

As circumstances change and additional data becomes available, Reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to Reserves estimates can arise from changes in, among other things, year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative. See "*Risk Factors*".

The Company does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table outlines the forecast for future development costs associated with Madalena assets and properties for the reserves categories noted below, calculated on an undiscounted and a discounted (10%) basis:

Future Development Costs
Forecast Prices and Costs

	Combined		**Canada**		**Tunisia**	
Year	Proved Reserves CDN M$	Proved Plus Probable Reserves CDN M$	Proved Reserves CDN M$	Proved Plus Probable Reserves CDN M$	Proved Reserves US M$	Proved Plus Probable Reserves US M$
2009	1,074.5	1,137.0	441.25	503.75	517.14	517.14
2010	1,758.2	1,758.2	-	-	1,435.8	1,435.8
2011	5,828.5	10,818.8	-	-	4,759.5	8,834.6
Total (Undiscounted)	8,661.2	13,714.0	441.25	503.75	6,712.4	10,787.5
Total (Discounted at 10%)	7,295.7	11,209.6	407.48	465.18	5,624.9	8,773.84

Future development costs are capital expenditures which will be required in the future for Madalena to convert Proved Undeveloped Reserves and Probable Reserves to Proved Developed Producing Reserves.

Madalena intends to use internally generated cash flow from operations, debt (if available on favourable terms), new equity issues (if available on favourable terms), and farm outs or similar arrangements to finance its capital expenditure program. The cost of funding could negatively affect disclosed reserves or future net revenue depending on the source and nature of the funding but the impact can not readily be determined at this time. See "*Risk Factors*".

Other Oil and Gas Information

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Madalena has a working interest and which are producing or which Madalena considers to be capable of production as at December 31, 2008:

	Producing Wells				Shut-in Wells[(1)(2)]			
	Oil		Natural Gas		Oil		Natural Gas	
Location	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Canada:								
Edson	-	-	1	0.1	-	-	1	0.1
Brazeau	1	0.2	4	0.9	-	-	2	0.5
Tunisia – Remada Sud	-	-	-	-	1	.15	-	-
Total	1	0.2	5	1.0	1	.15	3	0.6

Note:

(1) "**Shut-in**" wells refers to wells that have encountered, and are capable of producing, crude oil or natural gas but which are not producing due to the timing of the well completion and/or tie in which is anticipated to occur in 2009.
(2) All non-producing oil and natural gas wells are located near existing infrastructure.

Properties With No Attributed Reserves

The following table sets forth Madalena's undeveloped land position as at December 31, 2008:

	Gross		Net	
Location	**Acres**	**Sections**	**Acres**	**Sections**
Tunisia, North Africa	2,299,040	3,592.2	344,856	538.8
Argentina, South America	280,000	437.5	220,800	344.9
Alberta, Canada	1,600	2.5	443	0.7
Total	2,580,640	4,032.2	566,099	884.4

In Tunisia, there are no work commitments established in the seismic option agreements. However during 2008, the Company participated in drilling the first test well in the Remada Sud block at a cost of $2,939,734 and paid for seismic evaluation work at Remada Sud and Hammamett in the amount of $265,742. Future work commitments at Remada Sud will involve a 3D seismic survey, production testing of the TT2 well, and at least one step out well. The Company will evaluate estimated costs of these activities in 2009 as they are determined. In March of 2009, the Company officially terminated its seismic option agreement on the Hammamet exploration block and does not anticipate any significant additional costs.

In Argentina, the Company agreed to work commitments on the Cortadera, Curamhuele, and Coiron Amargo blocks. At December 31, 2008, the Company estimates its share of the remaining work commitments to be US $5,628,000 which the Company has until November of 2010 to complete.

Forward Contracts and Marketing

The Company does not have any forward contracts or hedges currently in place.

Additional Information Concerning Abandonment Costs

Madalena estimates well abandonment costs on an area-by-area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. Estimated costs of abandonment were included in the PLA Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is $1,433,000 undiscounted ($578,000 using a 10% discount rate) for Canada and Tunisia combined. 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Company in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The table below indicates the expected timing of well abandonment costs for the Company.

The Company uses industry historical costs to estimate its abandonment costs when available. The costs are estimated on an area-by-area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Company has 13 gross wells (2.34 net) in Canada, 1 gross well (0.15 net) in Tunisia, and 2 gross (1.4 net) wells in Argentina, for which it expects to incur abandonment costs.

The following table sets forth abandonment costs deducted in the estimation of the Company's future net revenue:

Forecast Prices and Costs (Total Proved)

Year	Canada Abandonment Costs (Undiscounted CDN M$	Tunisia Abandonment Costs (Undiscounted) US M$	Total Abandonment Costs (Undiscounted) CDN M$
2011	$11.0	-	$11.0
2012	6.2	-	6.2
2013	6.8	-	6.8
2018	6.8	1,097.0	1,350.3
2019	6.8	-	6.8
2021	10.7	-	10.7
2022	9.9	-	9.9
2024	9.9	-	9.9
2027	21.4	-	21.4
Total Undiscounted	89.5	$1,097.0	1,433.0
Total Discounted @ 10%	35.0	443.7	578.4

Forecast Prices and Costs (Total Proved Plus Probable)

Year	Canada Abandonment Costs (Undiscounted CDN M$	Tunisia Abandonment Costs (Undiscounted) US M$	Total Abandonment Costs (Undiscounted) CDN M$
2011	$11.0	-	11.0
2013	6.2	-	6.2
2014	6.8	-	6.8
2019	-	2,611.1	3,197.5
2022	6.8	-	6.8
2023	6.2	-	6.2
2024	6.8	-	6.8
Thereafter	51.9	-	51.9
Total Undiscounted	95.7	2,611.1	3,293.2
Total Discounted @ 10%	28.2	960.1	1,204.0

Tax Horizon

Depending on levels of production, commodity prices, acquisitions and capital expenditures, Madalena will not begin paying current income taxes in the foreseeable future.

Costs Incurred

The following table summarizes capital expenditures (net of asset retirement costs and office equipment) related to the Company's activities for the year ended December 31, 2008 in thousands of CDN dollars:

	Canada	Tunisia	Argentina
Property acquisition costs			
Proved properties	1	-	-
Undeveloped properties	0	-	(124)
Exploration costs	0	3,205	5,178
Development costs	166	-	-
Total	167	3,205	5,054

Exploration and Development Activities

The Company did not participate in any exploratory or development wells in Canada or in Argentina during the year ended December 31, 2008. However, on March 28, 2008 the Company participated in one gross, 0.15 net exploratory well on the Remada Sud block in Tunisia. In Argentina, the Company participated in evaluating two existing well bores on the Curamhuele block, conducted seismic surveys, seismic evaluations and environmental evaluations on all three blocks, and made preparations for drilling the first exploration well on the Coiron Amargo block which was drilled and completed in the first quarter of 2009. See "*Principal Properties*"

See "*Principal Properties*" for a description of the Company's exploration and development plans for the Canadian properties. In Tunisia the terms of our option agreements do not specify specific exploration or development commitments, however the Company has participated in the Remada Sud TT-2 well which spud March 28, 2008 Madalena’s share of the cost of the well was approximately $2.9 million. The operators evaluation plans for the Remada Sud property include a 3D seismic survey, additional production testing, and at least one step out well, which will be used to prepare an evaluation plan for submission to ETAP by the end of 2009. In March of 2009 the Company terminated its seismic option agreement on the Hammamet property and therefore expects no further costs related to this area.

In Argentina, the Company agreed to work commitments on the Cortadera, Curamhuele, and Coiron Amargo blocks. At December 31, 2008, the Company estimates its share of the remaining work commitments to be US $5,628,000 for all three blocks which the Company has until November of 2010 to complete. At Cortadera, the remaining commitment on the property involves drilling one exploration well in the amount of US $1,100,000. Madalena anticipates that the cost of drilling an exploration well on the Cortadera block will exceed the commitment amount. Madalena is currently in the process of evaluating the seismic surveys for Cortadera in order to determine suitable drilling locations. At December 31, 2008 Madalena had substantially completed its commitments for exploration costs and seismic surveys at Curamhuele. The remaining commitment on the property involves drilling at least one exploration well in the amount of US $1,131,000. Madalena anticipates that the cost of drilling an exploration well on the block will exceed the commitment amount. Madalena is currently evaluating the seismic surveys completed on the block and the test results from the two well bores in order to evaluate potential development, tie-in and marketing options for the two well bores, as well as potential drilling locations for its first exploration well on the block. Madalena will need to evaluate its available cash resources before drilling the exploration wells on the Cortadera and Curamhuele blocks. At December 31, 2008 Madalena had substantially completed its commitments for exploration costs and seismic surveys at Coiron Amargo. The remaining commitment on the property involves drilling at least one exploration well in the amount of US $3,396,000. Madalena anticipates that the cost of drilling the CAN-X2 well which was drilled and completed in March of 2009 will fulfil its commitments on the Coiron Amargo block.

Production Estimates

The following table sets out the volume of the Company's gross working interest production estimated for the year ended December 31, 2009 as evaluated by PLA which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data and Other Information".

Forecast Prices and Costs

Total Proved

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/d)*
Canada	7	90	3	25
Tunisia	16	-	-	16
Total Proved	23	90	3	41

Total Proved Plus Probable

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/d)*
Canada	7	95	3	26
Tunisia	16	-	-	16
Total Proved	23	95	3	42

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2008			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production(1)				
Light and Medium Crude Oil (Bbls/d)	7.5	8.0	10.9	8.6
Gas (Mcf/d)	82.1	108.2	95.5	114.1
NGLs (Bbls/d)	3.2	2.8	3.9	4.6
Combined (Boe/d)	24.4	28.8	30.7	32.2
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	64.09	118.31	121.26	94.69
Gas ($/Mcf)	7.52	8.17	11.32	8.53
NGLs ($/Bbls)	55.90	108.00	106.20	77.80
Combined ($/Boe)	52.36	73.96	91.65	66.62
Royalties Paid (Net of ARTC)				
Light and Medium Crude Oil ($/Bbls)	14.49	29.72	29.51	44.60
Gas ($/Mcf)	2.25	1.91	5.92	0.91
NGLs ($/Bbls)	8.91	4.61	35.44	12.51
Combined ($/Boe)	13.19	15.88	33.39	16.97
Operating & Transportation Expenses ($/Boe)				
Light and Medium Crude Oil ($/Bbls)	18.31	22.77	19.85	24.72
Gas ($/Mcf)	2.15	1.57	1.85	2.23
NGLs ($/Bbls)	15.97	20.78	17.38	20.31
Combined ($/Boe)	14.96	14.23	15.00	17.39
Netback Received ($/Boe)(2)				
Light and Medium Crude Oil ($/Bbls)	31.29	65.82	71.90	25.37
Gas ($/Mcf)	3.12	4.69	3.55	5.39
NGLs ($/Bbls)	31.02	82.61	53.38	44.98
Combined ($/Boe)	24.21	43.86	43.26	32.26

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table indicates the Company's average daily production from its Canadian fields, which represents all of the Company's production for the year ended December 31, 2008:

	Light and Medium Crude Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	BOE (BOE/d)
Brazeau	8.7	95.1	3.39	28
Edson	-	4.9	.22	1.0
Total Alberta	8.7	100.0	3.61	29.0

The Company's production for the year ended December 31, 2008 was 58% natural gas and natural gas liquids and 42% light and medium crude oil.

The Company expects that rights to explore, develop and exploit zero net acres of its undeveloped land holdings will expire by December 31, 2009 in Canada or Argentina. In Tunisia Madalena expects 1,100,000 gross and 165,000 net undeveloped acreage at Hammamet to expire as a consequence of terminating it's seismic option agreement.

For the twelve months ended December 31, 2008, approximately 74% of the Company's gross revenue was derived from petroleum and natural gas production.

DIVIDEND POLICY

The board of directors of the Company will determine the timing, payment and amount of future dividends, if any, that may be paid by the Company from time to time based upon, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other business considerations as the board of directors considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares without nominal or par value. As at April 20, 2009, there were 111,743,702 Common Shares issued and outstanding. In addition, as at such date, there were an aggregate of 11,155,000 Common Shares reserved for issuance upon the exercise of outstanding options to purchase common shares.

Each Common Share entitles its holder to receive notice of and to attend all meetings of the shareholders of the Company and to one vote at such meetings. The holders of Common Shares are, at the discretion of the board of directors of the Company and subject to applicable legal restrictions, entitled to receive any dividends declared by the board of directors on the Common Shares, subject to prior satisfaction of all preferential rights attached to all shares of other classes of the Company ranking in priority to the Common Shares. The holders of Common Shares are entitled to share equally in any distribution of the assets of the Company upon the liquidation, dissolution, bankruptcy or winding-up of the Company or other distribution of its assets among its shareholders for the purpose of winding-up its affairs, subject to prior satisfaction of all preferential rights attached to all shares of other classes of the Company ranking in priority to the Common Shares.

MARKET FOR SECURITIES

The common shares of the Company trade on the TSXV under the symbol "MVN".

The following table sets forth the price range and volume of the Common Shares as reported by the TSXV from January 1, 2008 to December 31, 2008.

2008	High	Low	Volume
January	0.57	0.40	1,444,961
February	0.55	0.40	432,872
March	0.65	0.42	1,069,305
April	0.80	0.46	9,969,467
May	0.72	0.54	1,851,811
June	0.68	0.48	1,137,989
July	0.59	0.445	778,008
August	0.50	0.33	530,586
September	0.44	0.215	667,172
October	0.25	0.085	5,919,999
November	0.17	0.09	2,129,463
December	0.135	0.06	4,528,585

ESCROWED SECURITIES

As of the date hereof, 2,272,950 Common Shares issued and outstanding at the date of listing on the TSX Venture Exchange remain subject to escrow in accordance with the rules of the TSX Venture Exchange under a value security escrow agreement (the "**Escrow Agreement**") among the shareholders, the Company, and Computershare Trust Company of Canada, as trustee. The following table provides a summary of the percentage of original shares, number of shares and the dates of release of the original common shares subject to escrow.

%	Number of common shares released	Release Date
10%	757,650	At listing date – February 16, 2007
15%	1,136,475	6 months – August 16, 2007
15%	1,136,475	12 months – February 16, 2008
15%	1,136,475	18 months – August 16, 2008
15%	1,136,475	24 months – February 16, 2009
15%	1,136,475	30 months – August 16, 2009
15%	1,136,475	36 months – February 16, 2010

DIRECTORS AND OFFICERS

The name and place of residence of each director and officer, the offices held by each in the Company, and the principal occupation of the directors and officers, the period served as director and the number of securities of the Company owned by such individuals as at April 20, 2009 is as follows:

Name, Address and Position	Principal Occupation for the Previous 5 Years	Director Since	Number of Common Shares
Ken Broadhurst Alberta, Canada Director / President / Chief Executive Officer	Currently the President and Chief Executive Officer of Madalena; September 2001 to February 24, 2006, President and Chief Executive Officer of privately owned Era Oil & Gas Corp. and Egypt Production Interest Corp.	February 24, 2006	1,937,500
Dwayne Warkentin Alberta, Canada Director / Senior Vice President / Chief Operating Officer	Currently Chief Operating Officer of Madalena. Prior thereto, Chief Operating Officer and Vice President, Operations at Antrim Energy Inc., from 1999 to February 24, 2006.	February 24, 2006	1,600,000
Greg Ford Alberta, Canada Chief Financial Officer	Currently Vice-President, Finance and Chief Financial Officer of Madalena. Executive Director of Ernst & Young LLP from February 1999 until joining the Company.	N/A	300,000

Name, Address and Position	Principal Occupation for the Previous 5 Years	Director Since	Number of Common Shares
Ray Smith California, USA Director / Chairman (5) (6) (7)	Currently Chairman of the Board of Madalena and Cruiser Oil and Gas Ltd., and a Director of True Energy Trust, both public oil and gas exploration companies. Formerly Chairman and CEO of Cork Exploration Ltd., Rydal Energy, New Cache Petroleum, Corsair Energy, and Meridian Energy Corp.	October 12, 2005	4,971,500
Mike Lock Alberta, Canada Director(4) (5) (6)	Currently President of Upsilon Holdings Ltd., a privately owned consulting company.	December 29, 2005	510,000(1)
Ving Woo Alberta, Canada Director(4) (7)	Currently director of Madalena, and formerly a Director of Cork Exploration Inc., a public oil and gas company. Formerly Vice President, Engineering for Meridian Energy Corp. from September 2002 until March 2005. Formerly Vice President, Engineering for Corsair Exploration Inc. from July 1999 until April 2002. Formerly Vice President, Engineering for New Cache Petroleum from February 1996 until February 1999.	March 10, 2006	725,000
James K. Wilson Director(4)	Currently Vice-president Finance and Chief Financial Officer of Grizzly Resources Ltd., a private oil and gas company, and Director of Ironhorse Oil & Gas Inc., and Rock Energy Inc. Formerly Vice-President Finance and Chief Financial officer for a number of public companies including Grey Wolf Exploration Inc., Maxx Petroleum Ltd. and Chauvco Resources International Ltd.	June 18, 2007	81,000
Jay Reid Alberta, Canada Director(5)	Currently Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. Director of a number of publicly listed issues and currently serves as Corporate Secretary for Advantage Energy Income Fund, Profound Energy Inc., Orleans Energy Ltd. and Garreau Inc., four TSX listed issuers and other private issuers.	February 13, 2009	nil

Notes:

(1) Ms. Kathryn Lock, the spouse of Mike Lock, holds directly 500,000 Common Shares.
(2) 200,000 Common Shares are held by Mr. Mike Lock in trust for one minor and three adult children.
(3) 100,000 Common Shares are held in Mr. Woo's CIBC Wood Gundy RRSP account.
(4) Member of the Audit Committee.
(5) Member of the Corporate Governance Committee.
(6) Member of the Compensation Committee.
(7) Member of the Reserves Committee.

The directors and officers of the Company own, directly or indirectly, or control or exercise direction over 10,625,000 common shares, representing 9.51% of the issued and outstanding common shares.

Each director of the Company holds office from the time elected until the next annual meeting of the Company at which time they shall retire but, if qualified, shall be eligible for re-election. All officers of the Company, in the absence of agreement to the contrary, shall be subject to removal by resolution of the board of directors of the Company at any time, with or without cause.

Each of Ken Broadhurst, Dwayne Warkentin and Greg Ford devote their full time and attention to the business affairs of the Company.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To our knowledge, and other than as set forth below, no director or executive officer of the Company: (i) is, or has been in the last 10 years, a director, chief executive officer or chief financial officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days, (b) was subject to an event that resulted, after that person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, or (c) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

Mr. Mike Lock was Vice President of Land for Big Bear Exploration Inc. ("**Big Bear**"), which filed under the *Companies Creditor Arrangement Act* (Canada) in March of 1999. Mr. Lock left employment with Big Bear in November of 1999.

No director or officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Company will be subject in connection with the operations of the Company. In particular, certain of the directors and officers of the Company are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Company or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Company. See "*Directors and Officers*". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

HUMAN RESOURCES

The Company currently employs 4 full-time employees and 4 consultants. The Company intends to add additional professional and administrative staff as the needs arise.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no outstanding legal proceedings material to the Company to which the Company is a party or in respect of which any of its respective properties are subject, nor are there any such proceedings known to be contemplated. In addition, there were no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the 2008 financial year, no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and no settlement agreements entered into by the Company with a court relating to securities legislation or with a securities regulatory authority during the 2008 financial year.

TRANSFER AGENT AND REGISTRAR

Alliance Trust Company, at its principal offices in Calgary, Alberta is the transfer agent and registrar of the Common Shares of the Company.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by numerous factors beyond its control. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime effective January 1, 2009. The Company anticipates a potential increase in the royalty rate effective January 1, 2009 due to the implementation of the Alberta royalty framework. The calculation of the royalties payable to the Government under the NRF is dependent on many factors including commodity prices, well production, as well as total depths of the producing wells. The royalties payable can change significantly depending on these factors and as such can be difficult to predict. As commodity prices increase, the Corporation's royalty rate will also increase with a maximum royalty rate of 50% on high producing wells in Alberta.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Company's costs, any of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Company will require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local 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 natural 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 of applicable environmental legislation 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 oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental regulations 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 have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others therefore depends upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. 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. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Company's reserves since that date.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and gas 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 oil and natural 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. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Company. Continued uncertainty in domestic and international credit markets could materially affect the Company's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Company's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Company's exploration and production facilities and other operations and activities emit greenhouse gases which will require the Company to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. See "Industry Conditions – Environmental Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar negatively impact the Company's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, which could negatively impact the market price of the Common Shares of the Company.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Competition

The petroleum industry is competitive in all its phases. The Company competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Issuance of Debt

From time to time the Company may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws 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 on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Company's claim which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company will not have insurance to protect against the risk from terrorism.

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Dividends

The Company has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other considerations as the board of directors of the Company considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company.

Conflicts of Interest

Certain directors of the Company are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Tunisian Risk Factors

Political Risks

Tunisia has experienced relative prosperity and stability under its leadership over the past two decades. Notwithstanding this relative stability, in the past, Tunisia has been affected by extremist Islamic militant activity. Tunisian authorities have implemented anti terrorism policies and security precautions. By law, parties organized on the basis of religion, region, race or language is forbidden. Despite this, there are groups in Tunisia dedicated to turning the country into an Islamic republic. The Tunisian government has taken steps to prevent the Islamic militants struggle in neighbouring Algeria from affecting Tunisia by increasing its military presence along the Tunisia/Algeria border, imposing visa restrictions and imposing strict controls on local militants. Tunisia is bordered by both Algeria and Libya. Both countries have experienced periods of civil, political and military unrest and Libya has been the subject of international sanctions; future unrest in any of the neighbouring countries could affect Tunisia.

Requirement for Permits and Licenses

The operations of the Company require a license, permits and in some cases renewals of existing licenses and permits from the government of Tunisia (named the licensing authority in the conventions). The Company believes that it currently holds or has applied for all necessary licenses and permits to carry on the activities, which it is currently conducting under applicable laws and regulations in respect of its properties, and also believes that it is complying in all material respects with the terms of such licenses and permits. However, the ability of the Company to obtain, sustain or renew such licenses and permits on acceptable terms is subject to change in regulations and policies and to the discretion of the applicable government.

Legal System

Tunisia may have a less developed legal system than more established economies, which may result in risks such as:

(i) effective legal redress in the courts of such jurisdictions, whether in respect of a breach of law or regulation, or, being difficult to obtain;

(ii) a higher degree of discretion on the part of governmental authorities;

(iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations;

(iv) inconsistencies or conflict between and within various laws, regulations, decrees, orders or resolutions; or

(v) relative inexperience of the judiciary courts in such matters;

In certain jurisdictions the commitment of local businesspeople, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for businesses. These may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance the joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities and the effectiveness of an enforcement of such arrangements in these jurisdictions cannot be assured. As a result of a limited infrastructure present in Tunisia, the land titles systems are not developed to the extent found in many more developed nations. Although the Company believes that it has good title to its oil and gas properties, there is little it can do to control this risk.

Argentina Risk Factors

Economic and Political Developments in Argentina, Including Export Controls

In the past few decades, the Argentine economy has experienced some periods of extreme volatility including periods of low or negative growth and variable levels of inflation. Inflation peaked in the late 1980's – 90's and in late-2001 there was a severe fiscal crisis, which resulted in restrictions on banking, the imposition of exchange controls, the suspension of payment of Argentina's public debt and the ceased to be tied to the U.S. dollar on a one-to-one basis. This further resulted in a year-long period of contractions in economic growth, elevated inflation and a volatile exchange rate. Shortly thereafter, Argentina experienced a period of GDP growth, normalized inflation, and strengthened public finances.

There is no guarantee of economic stability, which was shown when the Argentinean economy struggled again in 2008. As is the case in many other nations, recently, inflation has been rising and government popularity has decreased, due to the economic situation and the unpopularity of some of the programs the government tried to implement to deal with the global economic crisis. For example, the government applied export controls to agricultural products, which were highly unpopular and caused demonstrations and labour strikes across the country.

The Oil and Gas Industry in Argentina

The crude oil and natural gas industry in Argentina is subject to extensive regulation including land tenure, exploration, development, production, refining, transportation, and marketing, imposed by legislation enacted by various levels of government and with respect to pricing and taxation of crude oil and natural gas by agreements among the federal and provincial governments, all of which are subject to change and could have a material impact on our business in Argentina. The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on crude oil and natural gas exports. Any future regulations that limit the amount of oil and gas that we could sell or any regulations that limit price increases in Argentina and elsewhere could severely limit the amount of our revenue and affect our results of operations. In addition, oil and natural gas prices in Argentina are effectively regulated and as a result are substantially lower than those received in North America.

New Withholding Tax Regime

Recently, the government of Argentina introduced a new withholding tax regime for crude oil and refined oil products exported and sold domestically in Argentina. Currently all oil and gas producers in Argentina are operating without sales contracts. The new withholding tax regime was introduced without specific guidance as to its application. Producers and refiners of oil in Argentina have been unable to determine an agreed sales price for oil deliveries to refineries. Also, the price for refiners' gasoline production has been capped below the price that would be received for crude oil. Therefore, the refineries' price offered to oil producers reflects their price received, less taxes and operating costs and their usual mark up. Along with most other oil producers in Argentina, we are continuing deliveries to the refinery. The Provincial Governments have also been hurt by these changes as their effective royalty take has been reduced and capital investment in oilfields has declined.

Fluctuations in Foreign Currency Exchange Rates

Crude oil sales in Argentina are denominated in US dollars, natural gas sales are denominated in Argentinean Pesos and operating and capital costs are generally incurred in Argentinean Pesos and US dollars. Fluctuations in the US dollar, Argentinean Peso and exchange rates may cause a negative impact on revenue and costs and could have a material adverse impact on the Company's operations.

INDUSTRY CONDITIONS

Canada

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada and Alberta. All of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires a public hearing and the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Government of Alberta on December 10, 2008.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per meter royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the Company's production levels in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on Madalena's 2008 production it will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 Boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable**.**

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition at this time.

Argentina

Pricing and Marketing

Industry-wide, government-mandated wellhead price controls in Argentina were abandoned in 1989 when the oil and natural gas industry, dominated by Yacimientos Petroliferos Fiscales S.E. ("YPF"), was privatised. Price controls were eliminated in 1991 and prices remained unregulated until the economic crisis in late 2001. At that time, contracts for natural gas sales were converted from U.S. dollars to Argentine Pesos, concurrent with devaluation of the Argentine Peso to US$0.33. Since that time, natural gas prices for sales to consumers through local distribution companies have remained fixed and commercial sales prices are set by the market. In May 2004, a five percent export tax was imposed on gasoline and diesel, the export tax on oil was increased to 25 percent, and a 20 percent tax became effective on the export of natural gas, liquified natural gas ("LNG") and other gas products. The Federal Government of Argentina has indicated flexibility with respect to natural gas price deregulation and this has resulted in improved prices at the wellhead.

In August 2004, a progressive increase in export tax was instituted in Argentina on oil with reference to the price of WTI per barrel as quoted on the New York Mercantile Exchange ("NYMEX"). At WTI prices greater than US$32 per barrel, a tax was applied ranging from 25 percent up to 45 percent depending on the price of WTI. An amount equivalent to the export tax was applied to domestic sales. This has had the effect of limiting the actual realized price for domestic sales of oil in Argentina. For a description of the prices and netbacks achieved by the Company during the year ended December 31, 2007, see "Production History".

On November 16, 2007 the Government of Argentina published a resolution which set out changes to the computation of Argentina's export retention factor with respect to oil. Given the fiscal regime changes announced in the resolution, the Argentina Federal Government indicated that it would forthwith retain all of the increase in oil prices over an international reference price of US$60.90 per barrel. This export retention factor is applied to oil exported from Argentina.

Pipeline Capacity

Argentina's three major oil pipelines originate at Puerto Hernández, in the Neuquén Basin. Two pipelines are domestic, transporting oil north via the Repsol-YPF operated 50,000 bopd pipeline to the Lujan de Cuyo refinery near Mendoza and east via the Oldelval pipeline system moving crude over 1,200 kilometres to Puerto Rosales on the Atlantic. The 430 kilometre, 115,000 bopd Transandino pipeline is Argentina's only international oil pipeline, climbing over the Andes to a refinery in Chile. This pipeline discontinued transportation of oil in 2006 but is capable of being recommissioned.

Downstream

Repsol-YPF accounts for approximately half of the country's 624,575 bopd total refining capacity. Other companies with significant refining capacity include Shell CAPSA Limited (110,000 bopd) and Esso Petrolera Argentina S.R.L. (84,500 bopd). In December 2006, the Argentine government announced that it had reached agreement with several private oil companies with respect to building a new 150,000 bopd refinery in the country to produce refined products for both domestic consumption and export.

Relationships with Unions

Oil and gas activity in Argentina is largely unionized and Petro Andina's drilling, completions and workover operations are conducted by drilling operators employing unionized personnel. The Company is thus exposed to union activity including strikes, shut-downs, labour negotiations and other actions outside of the Company's direct control, which may have a material adverse effect on the operations of the Company. Petro Andina employs staff experienced in the area of union relations in order to mitigate these potential risks. During 2006, Petro Andina lost approximately 211 hours or 1.75 percent of available drilling time due to adverse union activity. During 2007 the Company lost approximately 456 hours or 1.3 percent of available drilling time due to adverse union activity.

Royalties, Turnover Taxes & Value Added Tax

Royalty determinations in Argentina are paid monthly to provincial authorities and must be submitted by field and concession. Production used by the concession holder for exploration or production operations is not subject to royalty. Royalties are deductible for income tax purposes. The standard royalty rate on production is 12 percent of the wellhead price for both oil and natural gas less deductions for transportation, treatment and commercialization costs between the wellhead and point of sale. This may be reduced on a case-by-case basis to a minimum of five percent taking into account productivity (marginal fields), condition and location of the producing wells as well as enhanced oil recovery projects. A rate of 15 percent applies to pre-commercial production from an exploration concession until such time as it is converted to an exploitation concession. In recent provincial bid rounds, companies have been given the option of bidding a higher royalty than prescribed by the national and provincial laws, but this is a voluntary decision which is applicable to the concession under bid only.

Additionally, the provinces levy a turnover tax varying between one and two percent of gross revenue less certain deductions. A value added tax ("VAT") at a rate of 21 percent is added on to domestic sales and is payable by the buyers of production. The VAT tax collected by the Company on sales is used to recover VAT paid on incurred costs. Stamp taxes are levied on transactions by way of contract at one percent to four percent depending on the jurisdiction in which the transaction takes place.

Income Taxes

A tax treaty exists between Argentina and Canada. Oil companies are subject to a generally applicable corporate tax regime. All successful exploration and field development costs, including intangible costs may be depreciated on a unit-of-production basis. Tax payers pay either income tax at a rate of 35 percent on corporate net profits or a minimum tax, based on net assets, whichever is the greater. Minimum tax was reinstated effective January 1999 and is levied on cumulative capital less accumulated depreciation plus an inflation adjustment at a rate of one percent. In April 1992, the tax base for locally incorporated companies was changed from Argentine source income to worldwide income.

Madalena is unaware of any prevailing currency restrictions with respect to repatriating after tax income from Argentina.

Oil and Gas Industry Regulations

The oil and natural gas industries in Argentina are subject to extensive regulation governing operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the federal and provincial governments, all of which are subject to change and could have a material impact on the Company's business, financial condition and results of operations. The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on oil and natural gas exports. As a result of these constraints, it is believed that energy reinvestment has been limited and overall hydrocarbon production has declined. Any change to these government imposed restrictions could have a material impact on Madalena's business, financial condition and results of operations.

The Hydrocarbons Law 17.319, enacted in June 1967, established the basic legal framework for the current regulation of exploration and production of hydrocarbons in Argentina. The Hydrocarbons Law empowers the National Executive to establish a national policy for development of Argentina's hydrocarbon reserves, with the main purpose of satisfying domestic demand. However, on January 5, 2007, Hydrocarbon Law 26.197 was passed by the Government of Argentina ("Ley Corta"). This new legal framework replaces article one of the Hydrocarbons Law 17.319 and provides for the provinces to assume complete ownership, authority and administration of the oil and natural gas reserves located within their territories, including offshore areas up to 12 marine miles from the coast line. This includes all exploration, exploitation and transportation concessions. This has led to the posting of large tracts of exploration acreage in "bidding rounds" through which the lands will be granted to successful bidding companies. The change of hydrocarbons administration will require producing companies to deal more extensively with the provincial governments who are now more directly involved in the day to day affairs of operations within their jurisdictions. Madalena intends to be an active participant in future bidding rounds in areas that it deems to be prospective.

Land Tenure

Exploration permits in Argentina grant exclusive rights to the concession holder to perform all types of exploration work and obtain an exploitation concession and a transportation concession after the declaration of a commercial discovery. The period under an exploration permit is divided into several phases. Work commitments are negotiated and specified separately for each individual phase of the exploration period. For the first exploration phase, commitments are expressed in work units with each activity equating to a different number of units. For the second and third exploration phases, commitments must comprise at least one well for each phase. At the end of each exploration phase, 50 percent of the remaining area must be relinquished or converted into an exploitation or evaluation concession. An evaluation concession allows a short term extension for a company to further evaluate the commercial potential of its exploration activities.

Exploitation concessions grant exclusive rights to the concession holder to produce hydrocarbons in areas of up to 250 square kilometres. The period for development and production is 25 years, although an extension of up to 10 years may be granted under terms and conditions to be established at the time of the extension. If a discovery is declared commercial before the end of the exploration period, the remaining portion of the exploration period is added on to the exploitation concession period.

Companies are permitted to hold, as operator, a maximum of five exploration permits in Argentina, but there is no limit on exploitation concessions.

At the end of 2008, the Argentinean government launched the Gas Plus and Petroleum Plus programs, new programs designed to stimulate investments in and production of natural gas and oil through providing incentives for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields. Companies must apply for the incentives, and several companies have started the process.

Environmental Regulations

Argentina has environmental standards for the industry, including surface maintenance and restoration, air quality and emission standards, operational safety standards and regular environmental audits. The implementation of environmental procedures is effected increasingly at the provincial level. A number of provinces have issued regulations relating to environmental impact assessments of activities within their boundaries.

Madalena conducted/intends to conduct a thorough baseline environmental study of its acreage at the time of the purchase of the assets prior to commencing operations. Environmental reviews are completed and environmental permits are obtained from the provincial authorities prior to undertaking any operations. The Company also conducts annual environmental audits of its operational areas which are tabled or available to federal and provincial regulators.

Legal & Political

Argentina is governed by a tripartite system of government made up of an Executive Power, a Legislative Power, and a Judicial Power established by a written Constitution passed in 1853. The Head of Government and Chief of State is a President elected by popular vote for a term of four years. The Argentine Republic comprises 23 provinces and the City of Buenos Aires. Each province has its own constitution which must state its administration of justice and municipal autonomy, and the scope and content of its institutional, political, administrative and financial orders.

Market Conditions

Overview

The oil and natural gas industry in Argentina is mature, having been established more than 100 years ago on December 13, 1907 when oil was discovered in Comodoro Rivadavia. Argentina is a significant South American energy producer and consumer and a net energy exporter, primarily to neighbouring Brazil and Chile.

The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on oil and natural gas exports. As a result of market uncertainty, energy reinvestment has been limited and overall hydrocarbon production has declined.

Exploration & Production

Two onshore basins represent the vast majority of Argentina's oil production: the Neuquén Basin, located in western-central Argentina, and the Gulf of San Jorge, in the southeast part of the country. Outside the established onshore basins, there has been some limited interest in exploring offshore oil resources. The Neuquén, Salta, Tierra del Fuego, and Santa Cruz regions contain most of Argentina's natural gas production, with the Neuquén region accounting for over half of the country's total production. As is the case in the oil sector, Argentina has begun to look towards its offshore basins as its traditional production centers have matured.

Tunisia

Trends

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels. The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

The Company is required to pay tax and royalties on oil and gas production in Tunisia. Going forward, a change in mix of production between oil and gas production or a change in the form of production could have a significant impact on the tax payable by the Company. In addition, Tunisian tax is calculated on a field-by-field basis and tax losses available for carry forward in one field cannot be offset against taxable profits in other fields. The tax payable going forward in Tunisia could therefore be significantly impacted by which Tunisian fields are profitable and the availability of tax losses to offset those profits.

Oil and Gas Industry Regulations

The Tunisian Hydrocarbon Code which was promulgated in 1999 (and subsequently amended) regulates activities associated with prospecting, exploration and production of hydrocarbons in Tunisia ("**Hydrocarbon Code**"). Petroleum resources found in the subsoil of Tunisia and off the Tunisian continental shelf belong to the Tunisian state. The right to conduct petroleum operations in Tunisia is granted in the form of an authorisation or concession granted by the Tunisian state. The Tunisian Ministry of Energy and Mines issues concessions and authorisations for the exploration and development of hydrocarbons in consultation with the hydrocarbon consultative committee. Entreprise Tunisienne D'Activites Petrolieres ("ETAP"), is a state-owned industrial and commercial company which is responsible for the management of hydrocarbon exploration and production activities on behalf of the Tunisian state. There are three types of authorisations and concessions under which exploration for hydrocarbons may be permitted under Tunisian hydrocarbon regulations. These are a: (i) prospecting authorisation, which permits geological studies over unexplored or under-explored areas; (ii) prospecting permit, which permits geophysical works and gives a priority right for the permit holder to convert to an exploration permit upon satisfaction of certain conditions; and (iii) an exploration permit, which permits geological and geophysical data acquisition, processing and interpretation of an area, and drilling of a number of exploration wells. The full term of an exploration licence is 5 years which can be extended by a further 8 years. An exploration licence obliges the licensee to undertake minimum work obligations. The maximum term of a production licence is 30 years which can be extended by a further 30 years. The concession holder may form a joint venture with ETAP, in which case ETAP will participate in the concession with a maximum fixed rate fixed and will reimburse the concession holder for part of its expenditure associated exploration and exploitation activities up to a stated participation rate. Alternatively, the Hydrocarbon Code also provides for the conclusion of a production sharing agreement with ETAP, pursuant to which ETAP is the owner of the concessions and exploration permits. A production sharing agreement will only be concluded with companies which have experience in similar operations and meet certain criteria. Other Tunisian regulations impose a number of obligations on concession holders that are primarily aimed at the efficient, safe and the most environmentally appropriate means by which hydrocarbons can be produced.

Land Tenure

Environmental Regulations

The operations of the Company that are conducted in Tunisia are subject to environmental regulations promulgated by the Government of Tunisia. Current environmental legislation in Tunisia provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil, condensate and natural gas operations. In addition, certain types of operations may require the submission and approval of environmental impact assessments. The existing operations of the Company are subject to such environmental policies and legislation. Environmental legislation and policy is periodically amended. Such amendments may result in stricter standards and enforcement and in more stringent fines and penalties non-compliance. Environmental assessments of existing and proposed projects carry a heightened degree of responsibility for companies and their directors, officers and employees. The costs of compliance associated with changes in environmental regulations could require significant expenditures, and breaches of such regulations may result in the imposition of material fines and penalties. In an extreme case, such regulations may result in temporary or permanent suspension of production operations. There can be no assurance that these environmental costs or effects will not have a material adverse effect on the future financial condition or results of the operations of the Company.

Legal & Political

Tunisia is a republic governed by a tripartite system of government made up of an Executive Power, a Legislative Power, and a Judicial Power established by a written Constitution passed in 1959, with amendments in 1988 and 2002. The Chief of State is a President elected by popular vote for a term of five years (with no term limits) and the Head of Government is a Prime Minister appointed by the President. The Tunisian Republic comprises 24 governorates. Each province has its own constitution which must state its administration of justice and municipal autonomy, and the scope and content of its institutional, political, administrative and financial orders.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Company, any shareholder who beneficially owns more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transactions since the beginning of the Company's last completed financial year or in any proposed transaction which has materially affected or will materially affect the Company except as described herein.

MATERIAL CONTRACTS

Except for contracts entered into by the Company in the ordinary course of business or otherwise disclosed herein, the Company has no contracts which can reasonably be regarded as material.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or related to, the Company's most recently completed financial year other than PLA, the Company's independent engineering evaluators and KPMG LLP, the Company's auditors.

To the knowledge of the Company, PLA, or principals thereof, did not have any registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of the Company's associates or affiliates either at the time they prepared the statement, report or valuation prepared by them, at any time thereafter or to be received by them.

KPMG LLP has advised the Company that they are independent within the meaning of the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta and its partners did not hold any registered or beneficial ownership interests, directly or indirectly, in the securities of the Company or its associates or affiliates.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, is contained in the Company's Information Circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in the Company's financial statements and management's discussion and analysis for the most recently completed financial year. Documents affecting the rights of security holders, along with other information relating to the Company, may be found on SEDAR at www.sedar.com.

SCHEDULE A

FORM 51-101F2
Report on Reserves Data
By Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Madalena Ventures Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs:

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2008, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)[1]			
			Audited	Evaluated	Reviewed	Total
Paddock Lindstrom & Associates Ltd.	April 16, 2009	Canada	Nil	$1,893,117	Nil	$1,893,117
Paddock Lindstrom & Associates Ltd.	April 16, 2009	Tunisia	Nil	$6,995,742	Nil	$6,995,742
TOTAL			Nil	$8,888,859	Nil	$8,888,859

[1] This amount should be the amount disclosed by the *reporting issuer* in its statement of *reserves data* filed under item 1 of section 2.1 of *NI 51-101*, as its *future net revenue* (before deducting *future income tax expenses*) attributable to *proved* plus *probable reserves,* estimated using *forecast prices and costs* and calculated using a discount rate of 10 percent (required by section 2 of Item 2.2 of *Form 51-101F1*). The values represented are shown in Canadian dollars.

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta,

Execution Date: April 17, 2009

Ronald M. Bojechko, P.Eng.
Vice President

SCHEDULE "B"

FORM 51-101 F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Madalena Ventures Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with the securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has on the recommendation of the Reserves Committee approved:

- the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

- the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

- the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, our variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Dated at Calgary, Alberta, this 23rd day of April, 2009

(signed) "*Ken Broadhurst*"	(signed) "*Ving Y. Woo*"
Ken Broadhurst, President & Chief Executive Officer and Director	Ving Y. Woo, Director and Chairman of the Reserves Committee
(signed) "*Dwayne Warkentin*"	(signed) "*Raymond G. Smith*"
Dwayne Warkentin, Senior Vice-President & Chief Operating Officer	Raymond G. Smith, Director and Chairman of the Board of Directors