Marauder Resources East Coast Inc.

STATEMENT OF RESERVE DATA AND OTHER OIL AND GAS INFORMATION

National Instrument 51-101F1

EFFECTIVE DECEMBER 31, 2009

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TABLE OF CONTENTS

ABBREVIATIONS

bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Mcf/d	thousand cubic feet per day
bbl/d	barrels per day	MMBtu	million British Thermal Units
NGLs	natural gas liquids	Bcf	billion cubic feet
BOE/d	barrels of oil equivalent per day	GJ	gigajoule

API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent generally accepted on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
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

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically recoverable from discovered resources, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"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.

“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 + probable reserves.

“Possible” reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves.

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories.

“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 (e.g. 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.

“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.

“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.

“Undeveloped” reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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, possible) 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 sub-divide 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 recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

The following terms, used in the preparation of the Evaluation (as defined herein) and this document have the following meanings:

“Associated gas” means the gas cap overlying a crude oil accumulation in a reservoir.

“Company” or **“Marauder”** means Marauder Resources East Coast Inc.

“Crude oil” or **“Oil”** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids. Classes of crude oil are often reported on the basis of density, sometimes with different meanings. Acceptable ranges are as follows:

Light less 870 kg/m3 (greater than 31.1°API)

Medium	870 to 920 kg/m3 (31.1 to 22.3°API)
Heavy	920 to 1,000 kg/m3 (22.3 to 10°API)
Extra-heavy	greater than 1,000 kg/m3 (less than 10°API)

“Development costs” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
(d) provide improved recovery systems.

“Development well” means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“Exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
(c) dry hole contributions and bottom hole contributions;
(d) costs of drilling and equipping exploratory wells; and
(e) costs of drilling exploratory type stratigraphic test wells.

“Exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

“Fair Market Value” is considered to be the value that a successful buyer would pay for an asset in the marketplace. Because all of the conditions of a “Fair Market Value” are seldom met, the “Market Value” is rarely equal to the “Fair Market Value”.

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"Future prices and costs" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;
(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"Future income tax expenses" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"Future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using forecast prices and costs.

"Gross" means:

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

"Market Value" is considered to be the value that a successful buyer would pay for an asset in the marketplace. Because all of the conditions of a "Fair Market Value" are seldom met, the "Market Value" is rarely equal to the "Fair Market Value".

"Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

“Natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

“Net” means

(a) in relation to the Company’s interest in production or reserves its working interest (operating or non operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
(b) in relation to the Company’s interest in wells, the number of wells obtained by aggregating the Company’s working interest in each of its gross wells; and
(c) 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.

“Non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“Operating costs” or “production costs” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“Production” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“Property” includes:

(a) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

“Property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;
(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
(c) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

“Proved property” means a property or part of a property to which reserves have been specifically attributed.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“Service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

“Solution gas” means natural gas dissolved in crude oil.

“Stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) exploratory type” if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“Support equipment and facilities” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

“Unproved property” means a property or part of a property to which no reserves have been specifically attributed.

“Well abandonment costs” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do no include costs of abandoning the gathering system or reclaiming the well site.

“Well abandonment and reclamation costs” means costs of abandoning a well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE

In accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and the standards set out in the Canadian Oil and Gas Evaluation Handbook ("the COGE Handbook"), Martin & Brusset Associates ("Evaluator") prepared a report (the "Reserve Report") dated March 30, 2010. The Reserve Report evaluated, as at December 31, 2009, Marauder Resources East Coast Inc.'s crude oil reserves. The tables below are a summary of the crude oil reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the Reserve Report based on forecast price and cost assumptions. The tables summarize the data contained in the Reserve Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The present worth values of the net production revenue are presented before and after income taxes. The values are in Canadian dollars after deduction of all royalties, mineral taxes, estimated future capital and operating costs and well abandonment costs. The estimated values shown may not necessarily represent the fair market value or the market value of these reserves. There are inherent risks in estimates of oil and gas reserves and values because few of the factors involved are known with certainty and no guarantee is given or implied that the forecast production or cash flows presented in the Reserve Report will be achieved.

The reserve estimates in the Reserve Report have been prepared in accordance with National Instrument NI51-101 and the standards set out in the COGE Handbook and the aggregate reserves and future net revenues presented in the Reserve Report are considered to be compliant with the confidence levels required by NI51-101. Extraction of specific evaluations for an individual property or group of properties will not necessarily reflect the same confidence levels as expressed in the report for the aggregate.

It is unlikely that the actual remaining quantities recovered will exceed the aggregate of the estimated probable plus possible reserves. A reasonable time line for the development of these reserves has been estimated, however, significant capital will be required and the Company does not have a budgeted schedule. Development will be driven by market conditions and the Company's ability to raise capital and attract partners. It has been assumed that adequate financing can be arranged such that the Company can proceed with development, however no assurance is given or implied that the development timelines can be met.

Prices and escalation rates forecast by the Evaluator have been made using assumptions which appear reasonable under present conditions. However, in view of the recent fluctuations in world crude oil prices, North American natural gas prices, currency exchange rates and other factors, there is no assurance that these projections will turn out to be accurate.

The Reserve Report represents the Company's crude oil reserves only. All evaluated properties are in Canada and all monetary values are expressed in Canadian dollars unless stated otherwise.

The Reserve Report is based on certain factual data supplied by the Company and the Evaluator's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts was provided by Marauder Resources East Coast Inc. The Evaluator has not independently verified the accuracy and completeness of all the data provided. Any conflicts in the data or questions as to the validity or sufficiency of the data arising from access to public data or based on the Evaluator's industry experience and judgment were resolved through discussions with the Company. No new technical information became available in 2009.

FINDING AND DEVELOPMENT COSTS

Finding and development costs ("F&D Costs") are predominantly used to determine the average cost of replacing reserves and if exploration and development expenditures are adding reserves at a cost that is less than or equal to net asset value. If the cost of reserves additions exceeds net asset value, then the Company will have a rate of return less than the discount rate used to determine value. F&D Costs are also a measure of success. They are calculated by dividing the total of all exploration and development costs, including all plants and production facilities, by the proved reserves added. In accordance with National Instrument 51-101 Disclosure of Oil and Gas Activities ("NI 51-101") F&D Costs are calculated by dividing the aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs by the change in reserves for the same period. The recycle ratio is a key indicator for evaluating the management of the Company and its ability to re-invest funds during the year. The ratio is determined by dividing the operating netback per barrel of oil equivalent by the current year's reserves finding and development costs per BOE.

No calculation is done for the Company's F&D Costs as development of the evaluated properties has not commenced. There is no assurance that development of the properties will occur.

SUMMARY OF OIL, GAS AND NATURAL GAS LIQUIDS RESERVES

Effective December 31, 2009
FORECAST PRICES AND COSTS

	RESERVES Before Income Tax									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVE CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Probable undeveloped	4,740	4,623	0	0	0	0	0	0	4,740	4,623
Possible undeveloped	9,025	8,595	0	0	0	0	0	0	9,025	8,595
Probable plus Possible	13,765	13,219	0	0	0	0	0	0	13,765	13,219

	RESERVES After Income Tax									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVE CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Probable undeveloped	4,740	4,623	0	0	0	0	0	0	4,740	4,623
Possible undeveloped	9,025	8,595	0	0	0	0	0	0	9,025	8,595
Probable plus Possible	13,765	13,219	0	0	0	0	0	0	13,765	13,219

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

Effective December 31, 2009
FORECAST PRICES AND COSTS

	NET PRESENT VALUES OF FUTURE NET REVENUE								
	BEFORE INCOME TAX DISCOUNTED AT (%/YEAR)				AFTER INCOME TAX DISCOUNTED AT (%/YEAR)				UNIT VALUE BEFORE INCOME TAX DISCOUNTED At 10%/YEAR
RESERVE CATEGORY	5 (M$)	10 (M$)	15 (M$)	20 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	($/Bbl)
Probable undeveloped	158,155	120,077	92,217	71,556	105,060	78,874	59,836	45,813	25.33
Possible undeveloped	429,391	315,896	235,742	178,198	312,355	228,698	169,801	127,652	35.00
Probable plus Possible	587,546	435,973	327,959	249,754	417,415	307,572	229,637	173,465	31.67

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

Effective December 31, 2009
FORECAST PRICES AND COSTS

RESERVE CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABAND. COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAX (M$)	INCOME TAX (M$)	FUTURE NET REVENUE AFTER INCOME TAX (M$)
Probable undeveloped	468,529	11,595	48,403	179,417	18,127	210,988	69,380	141,608
Possible undeveloped	914,265	43,574	93,839	182,963	854	593,035	159,689	433,346
Probable plus Possible	1,382,794	55,169	142,242	362,380	18,981	804,022	229,068	574,954

FUTURE NET REVENUE BY PRODUCTION GROUP

Effective December 31, 2009
FORECAST PRICES AND COSTS

RESERVE CATEGORY	PRODUCTION GROUP (1)	FUTURE NET REVENUE BEFORE INCOME TAX (discounted at 10%/year) (M$)	UNIT VALUE ($/Bbl)
Probable undeveloped	**Light and Medium Crude Oil** (including solution gas and other by-products)	120,077	25.33
Possible undeveloped	**Light and Medium Crude Oil** (including solution gas and other by-products)	315,896	35.00
Probable plus Possible	**Light and Medium Crude Oil** (including solution gas and other by-products)	435,973	31.67

(1) All evaluated reserves are light and medium crude oil

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

Effective December 31, 2009
FORECAST PRICES AND COSTS

The Evaluator employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2009 in estimating the Company's reserves data using forecast prices and costs.

	CRUDE OIL				INFLATION RATES(1) (%/Year)	EXCHANGE RATE(2) (US/$Cdn)
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40° API ($Cdn/bbl)**	**Cromer Medium 29.3° API ($Cdn/bbl)**	**Hardisty Heavy 12° API ($Cdn/bbl)**		
2010	78.50	81.50	76.50	65.50	--	0.95
2011	82.50	86.00	79.00	68.00	2.0%	0.95
2012	86.00	90.00	82.00	68.00	2.0%	0.95
2013	90.00	94.00	85.00	68.00	2.0%	0.95
2014	93.00	97.00	87.00	69.00	2.0%	0.95
Thereafter					2.0%	0.95

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

RECONCILIATION OF COMPANY GROSS RESERVES BY PRODUCT TYPE (1)

BASED ON FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL		
FACTORS	**Gross Probable (Mbbl)**	**Gross Possible (Mbbl)**	**Gross Probable Plus Possible (Mbbl)**
December 31, 2008	4,740.0	9,025.0	13,765.0
Additions:	0.0	0.0	0.0
Extensions	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0
Reductions:	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0
Production	0.0	0.0	0.0
Fluctuations:	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0
Technical Revisions	0.0	0.0	0.0
December 31, 2009(2)	4,740.0	9,025.0	13,765.0

(1) All evaluated reserves are light and medium crude oil
(2) No new information has become available on the evaluated properties since the previous evaluation

UNDEVELOPED RESERVES

The following discussion generally describes the basis on which the Company attributes probable and possible undeveloped reserves and its plans for developing those undeveloped reserves.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure, 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, possible) to which they are assigned.

Probable Undeveloped Reserves
Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

Possible Undeveloped Reserves
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated probable plus possible reserves.

The Company has no scheduled plans for development of probable and possible undeveloped reserves which is consistent with the Reserve Report assumptions.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering, and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company’s estimates are based on current production forecasts, prices and economic conditions. An independent engineering firm, Martin & Brusset Associates, evaluated the Company’s crude oil reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserve estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserve estimates are accurate, revisions arise as new information becomes available. For a discussion of further risks and uncertainties, please refer to “Business Risks and Uncertainties” in the Company’s management's discussion and analysis of operations and financial condition for the year ended December 31, 2009, which is available under the Company's profile at www.sedar.com.

FUTURE DEVELOPMENT COSTS

The table below sets out the development costs deducted in the estimation of future net revenue attributable to probable reserves and probable plus possible reserves (using forecast prices and costs) before income tax.

	Total Probable Estimated Using Forecast Prices and Costs (M$)	Total Probable Plus Possible Estimated Using Forecast Prices and Costs (M$)
2013	45,948	95,320
2014	48,764	33,528
2015	62,712	87,526
2016	20,271	60,813
2017	1,723	62,029
2018	-	23,164
Total for All Years Undiscounted	179,417	362,380

As the Company has no established revenue, its principal source of funds is from the issuance of common shares. In order to maintain or adjust its capital structure, the Company will consider the potential level of credit facilities that may be available as a result of the value of the Company's assets, availability of other sources of debt with different characteristics than conventional debt, the sale of assets and new equity if available on favourable terms. The costs of funding should not have a material affect on the disclosed reserves or future net revenue.

OIL AND GAS PROPERTIES

Balmoral, Nova Scotia

The Company holds a 50% interest in the shallow rights on this lease. The Company acquired 3D seismic information on this property in 2005. Probable reserves were calculated based on the net pay at the CP-3A well and production is estimated to start January, 2016 at a rate of 15,000 BOPD, declining exponentially to the economic limit. Capital costs have been included to drill and equip two horizontal wells.

Cohasset, Nova Scotia

The Company holds a 50% interest in the shallow rights in this lease. Cumulative production from the Cretaceous sands on the Cohasset Block exceeded 23.5 MMSTB prior to the field being shut-in. In 2005 the Company acquired new 3D seismic information as well as the well logs from two previously confidential wells.

Production forecasts beginning in January, 2015 were generated based on a total initial production rate of 15,000 BOPD declining exponentially thereafter. Capital costs have been included to drill, complete and equip two multilateral horizontal wells from a single platform.

Panuke, Nova Scotia
The Company has a 50% interest in the shallow rights in this lease. Cumulative oil production from six different stacked Cretaceous Sand intervals exceeded 16.1 MMSTB before the field was shut-in.

Production forecasts beginning in January, 2014 have been generated based on an initial rate of 15,000 BOPD declining exponentially thereafter. Capital costs have been included to drill, complete and equip three multilateral horizontal wells from a single platform.

The Company does not hold a working interest in any wells as at December 31, 2009.

PROPERTIES WITH NO ATTRIBUTED RESERVES

	Gross Acres	Net Acres	Lands to Expire in 2010
Nova Scotia	0.0	0.0	0.0
Other	0.0	0.0	0.0

FORWARD CONTRACTS

The Company does have any forward contracts as at December 31, 2009.

ADDITIONAL INFORMATION CONCERNING ABANDONMENT AND RECLAMATION COSTS

Well abandonment costs are included for 7 gross (3.5 net) wells in the Reserve Report as a deduction in arriving at future net revenue. The estimated total abandonment costs (net of salvage value) included in the Reserve Report for the properties included under the probable and possible reserves categories is $18,981,000 undiscounted before income tax. Costs associated with abandoning gathering systems and reclaiming the well sites are not considered in the future net revenue figures. These abandonment costs are forecast to occur in 2018.

TAX HORIZON

The Company was not required to pay income taxes for the period ended December 31, 2009. Based on forecasted commodity prices and timing of development and production used in the Reserve Report, the Company estimates that it will be taxable in the fiscal year 2014.

COSTS INCURRED - EXPLORATION AND DEVELOPMENT ACTIVITIES

Marauder made no capital expenditures on oil and natural gas properties for the year ended December 31, 2009.

PRODUCTION ESTIMATES

The following table discloses the total annual volume of daily crude oil production (gross to the Company) estimated by the Evaluator in the Reserve Report. All reserves evaluated in the Reserve Report are of the product type light and medium oil which is measured in barrels per day in the following table.

RESERVE CATEGORY	2014	2015	2016	2017	2018
	Bbl/d	Bbl/d	Bbl/d	Bbl/d	Bbl/d
Probable undeveloped	4,668	4,521	3,669	121	-
Possible undeveloped	1,608	5,825	8,104	6,454	2,710
Probable plus Possible	6,276	10,346	11,773	6,575	2,710

The Panuke field accounts for approximately 45% of the estimated production.

PRODUCTION HISTORY

The Company has not commenced production.