



PETROBANK

STRENGTH IN OUR RESOURCES

**ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2008**

MARCH 17, 2009

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ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

bbl/d	Barrels of oil per day	Mbbl	Thousand barrels
boe	Barrels of oil equivalent	mcf	Thousand cubic feet of natural gas
boe/d	Barrels of oil equivalent per day	mcf/d	Thousand cubic feet of natural gas per day
bopd	Barrels of oil per day	Mmbbl	Million barrels
km	kilometre	mmcf	Million cubic feet of natural gas
km²	Square kilometres	mmcf/d	Million cubic feet of natural gas per day
m	metre	NGL	Natural gas liquids
m³	Cubic metre	US\$	United States dollars
M\$	Thousands of Canadian dollars		

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

“**ABCA**” means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, together with all regulations promulgated thereunder;

“**ANH**” means Agencia Nacional de Hidrocarburos, the Colombian National Hydrocarbon Agency;

“**API**” means as a degree of gravity that provides a relative measure of crude oil density;

“**Archon**” means Archon Technologies Ltd., a wholly-owned subsidiary of Petrobank, incorporated under the laws of the Province of Alberta;

“**Board**” means the Board of Directors of Petrobank;

“**Canadian Business Unit**” or “**CBU**” means the conventional reserves, operations and properties held by the Company, as more particularly described under the heading “*Canadian Business Unit Overview*”;

“**CAPRITM**” means the Company’s CAPRITM technology, which is an enhancement to the Company’s THAITM technology offering the potential for further in-situ upgrading through the use of a well-bore integrated catalyst;

“**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 and Petroleum;

“**common shares**” means the issued and outstanding common shares in the capital of the Company;

“**Company**” means Petrobank Energy and Resources Ltd., and where applicable also refers to its subsidiaries;

“**CSS**” means cyclic steam stimulation;

“**Dawson Property**” means Petrobank’s 50% interest in 2,880 acres of heavy oil lands and related assets in the Peace River region of northwest Alberta;

“**D&M**” means DeGolyer and MacNaughton, independent oil and gas reservoir engineers of Dallas, Texas, USA;

“**D&M Report**” means the independent engineering evaluation of Petrominerales’ crude oil reserves in Colombia prepared by D&M, dated February 27, 2009, with an effective date of December 31, 2008;

“**ERCB**” means Energy Resources and Conservation Board;

“**GAAP**” means Canadian generally accepted accounting principles;

“**Glover Lease**” means, collectively, the oil sands leases held by Whitesands in respect of 10.25 sections (6,560 net acres) of land located in Township 75, Range 9, within the Province of Alberta, approximately 6.5 kilometres south of the Whitesands Leases;

“**Gross**” means: (a) in relation to the Company’s interest in production and reserves, its “Company gross reserves”, which are the Company’s working 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;

“**Heavy Oil Business Unit**” or “**HBU**” means the operations, properties and assets of Whitesands, as more particularly described under the heading “*Heavy Oil Business Unit Overview*”;

“**IPC**” means an incremental production contract in the country of Colombia;

“**Kerrobert Property**” means Petrobank’s 50 percent interest in three sections of land in the Kerrobert Mannville heavy oil pool, in Saskatchewan;

“**Latin American Business Unit**” or “**LABU**” means the operations, properties and assets of Petrominerales, in which the Company has an indirect 76.5% interest, as more particularly described under the heading “*Latin American Business Unit Overview*”;

“**McDaniel**” means McDaniel and Associates Consultants Ltd., independent petroleum engineers, of Calgary, Alberta, Canada;

“**McDaniel Report**” means the evaluation of Whitesands’ bitumen Reserves and Contingent Resources (excluding the Glover Lease, the Dawson Property, the Sutton Creek Property and the Kerrobert Property) based on forecast prices and costs dated February 24, 2009, with an effective date of December 31, 2008;

“**Net**” means: (a) in relation to the Company’s interest in production and reserves, its gross reserves, which are the Company’s working interest (operating and non-operating) share after deduction of royalties obligations, plus the Company’s royalty interest in production or reserves; (b) in relation to 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;

“**NI 51-101**” means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators;

“**Notes**” means Petrobank’s 3.00% convertible notes issued on May 4, 2007, maturing on May 4, 2012;

“**Peerless**” means Peerless Energy Inc.;

“**Petrobank**” means Petrobank Energy and Resources Ltd.;

“**Petrominerales**” means Petrominerales Ltd., an indirect subsidiary of Petrobank, in which Petrobank has a 76.5% interest, and includes, unless the context otherwise requires, Petrominerales’ wholly-owned subsidiary Petrominerales Colombia Ltd.;

“**PIHC**” means pre-ignition heating cycle (See “*THAI Process Steps*”);

“**Preferred Shares**” means the preferred shares of the Company, issuable in series;

“**Rocor**” means Rocor Resources Inc., a private company acquired by Petrobank on October 2, 2008;

“**SAGD**” means steam assisted gravity drainage;

“**Sproule**” means Sproule Associates Limited, independent petroleum engineers, of Calgary, Alberta, Canada;

“**Sproule Report**” means the independent engineering evaluation of the Company’s crude oil and natural gas reserves in Canada prepared by Sproule, dated March 11, 2009, with an effective date of December 31, 2008;

“**subsidiary**” has the meaning given to such term in the *Securities Act* (Alberta);

“**Sutton Creek Lease**” means, collectively, the oil sands licences held by Whitesands comprised of 23,040 acres of land located in the Province of Saskatchewan (Township 91, Ranges 24);

“**THAITM**” means Petrobank’s patented Toe-to-Heel-Air-Injection in-situ heavy oil recovery technique, which combines a vertical air injection well with a horizontal production well, indirectly owned through Archon;

“**TPC**” means Technology Partnership Canada;

“**TSX**” means the Toronto Stock Exchange;

“**Whitesands**” means Whitesands Insitu Partnership, a partnership between Petrobank and its wholly-owned subsidiary, Whitesands Insitu Inc.;

“**Whitesands Leases**” means, collectively, the oil sands and heavy oil leases held by Whitesands in respect of 62 sections (39,680 net acres) of land located in Townships 76-78, Ranges 8-10W4, within the Province of Alberta.

NOTES

General

Boe disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent an economic value at the wellhead.

Certain other terms used in this Annual Information Form but not otherwise defined herein shall have the same meanings as defined in NI 51-101 unless the context otherwise requires.

In this Annual Information Form, references to “dollars” and “\$” are to the currency of Canada, unless otherwise indicated.

Unless the context otherwise requires, reference in this Annual Information Form to “Petrobank” or the “Company” are to Petrobank Energy and Resources Ltd. and its subsidiaries including interests in joint ventures and partnerships.

Unless otherwise noted, the Company’s average daily production volumes disclosed herein are based on the Company’s working interest production before deduction of royalties paid to others and including royalty volumes received.

Non-GAAP Measures

This Annual Information Form contains financial terms that are not considered measures under Canadian generally accepted accounting principles (“GAAP”), such as operating netbacks. These measures are commonly utilized in the oil and gas industry and are considered informative for management and shareholders. Profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Operating netbacks may not be comparable to those reported by other companies nor should they be viewed as an alternative to other measures of financial performance calculated in accordance with GAAP.

NOTES ON RESERVES DATA

Notes on Reserves Data

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The reserves information provided herein in respect of Whitesands does not include the Glover Lease lands, the Dawson Property, the Kerrobert Property or the Sutton Creek Lease.

Crude oil, natural gas liquids and natural gas reserves estimates presented in the Evaluators’ reports are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is 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.

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 plus probable reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is only a 10 percent 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, 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 (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.

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 (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 reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible 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 reserve estimates and the effect of aggregation is provided in the COGE Handbook.

Estimated future abandonment and reclamation costs related to a property have been taken into account by the Evaluators 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.

Columns may not add due to rounding.

Contingent Resource Categories

In this Annual Information Form, the Company has disclosed estimated volumes of “contingent resources” or “resource” estimates. “Resources” are oil and gas volumes that are estimated to have originally existed in the earth's crust as naturally occurring accumulations but are not capable of being classified as “reserves” as described below. The following are excerpts from the definitions of resources and reserves, contained in Section 5 of the Canadian Oil and Gas Evaluation Handbook (“**COGE**”), which is referenced by the Canadian Securities Administrators in “*National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities*”: Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Resources and contingent resources do not constitute, and should not be confused with, reserves.

COGE defines “discovered” resources as those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into recoverable and unrecoverable categories, with the estimated future recoverable portion classified as reserves and contingent resources. Undiscovered resources are that quantity of petroleum that is estimated, as of a given date, to be contained in accumulations yet to be discovered.

The resources assigned to the Whitesands Leases have been classified as contingent. The contingent resources assigned to the Whitesands leases have been sub-classified as economic contingent resources and have been deemed to be economically viable under reasonable fiscal conditions.

Contingent resources have been determined for the following mutually exclusive categories:

- **Low Estimate:** This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P90 confidence level.
- **Best Estimate:** This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of the

central tendency of the uncertainty distribution (most likely/mode, P50/median, or arithmetic average/mean).

- **High Estimate:** This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P10 confidence level.

For a summary of the Company's Contingent Resources including Low, Best and High Estimates of Contingent Resources, see "*Summary of Heavy Oil Business Unit Contingent Resources*". The Company's Contingent Resources are summarized under the heading "*Summary of Heavy Oil Business Unit Contingent Resources*", but do not appear elsewhere in this Annual Information Form.

McDaniel defines the Best Estimate of an exploitable in-situ interval as a subsurface stratigraphic interval containing a minimum thickness of 10 metres of continuous bitumen-saturated sand, net of localized permeability barriers, with porosity and mass bitumen content (ratio of bitumen to water and mineral matter) meeting a minimum of 27 and eight percent, respectively, with a competent top reservoir seal. By continuous bitumen-saturated sand, it is intended that nothing that impedes steam or solvent transmission to any significant degree, either vertically or laterally can be present within the interval. Mudstones, impermeable sandstones, paleosols, coals, etc. are not included in net pay values and must not be laterally traceable over approximately one-hundred metres outwards in all directions from a particular wellbore. This distance corresponds to the established lateral sweep of most in-situ SAGD recovery schemes. A competent top reservoir seal is defined by McDaniel's as a shale or mudstone, sequence of sand and shale or mudstone, coal or some combination thereof, that can be expected to act as a permeability barrier on either a local or regional scale through application of the defined or anticipated recovery scheme.

McDaniel defines the Low Estimate and High Estimate of an exploitable in-situ interval as meeting all of the Best Estimate requirements with the exception of meeting a minimum thickness of 12 and eight metres of net bitumen-saturated sand, respectively.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. The use of statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These forward-looking statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form may contain forward-looking statements pertaining to the following:

- the characteristics of the Company's oil, heavy oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;

- supply and demand for oil and natural gas;
- expectations regarding the ability of the Company to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

With respect to forward looking statements contained in this Annual Information Form, the Company has made assumptions regarding:

- oil and natural gas production levels;
- commodity prices;
- general economic and financial market conditions;
- timing and amount of capital expenditures;
- availability of labour and drilling equipment;
- government regulation in the areas of taxation, royalty rates and environmental protection; and
- expectations and assumptions concerning the obtaining of necessary regulatory approvals.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- fluctuation in foreign currency exchange rates;
- financial resources of the Company;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves and undeveloped lands;
- geological, technical, drilling and processing problems;
- the ability to economically test, develop and utilize the technologies described herein;
- changes in legislation, risks associated with the Company's international operations;
- changes in environmental or tax laws and government incentive programs relating to the oil and gas industry; and
- the other factors discussed under the heading "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as may be required by applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Company to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

BUSINESS OF THE COMPANY

Petrobank Energy and Resources Ltd. is a Calgary-based oil and natural gas exploration and production company with operations in western Canada and Latin America. The Company operates high-impact projects through three business units and a technology subsidiary. The Canadian Business Unit is focused on developing a solid production platform from the Bakken light oil play in southeast Saskatchewan, and exploiting a large undeveloped land base through the application of new technology to large oil and gas resource opportunities. The Latin American Business Unit, operated by Petrobank's 76.5% owned TSX-listed subsidiary, Petrominerales Ltd. (TSX: PMG), is a Latin American-based exploration and production company producing oil in Colombia with 16 exploration blocks covering a total of 1.9 million acres in the Llanos and Putumayo Basins of Colombia and 2.6 million acres in the Ucayali Basin of Peru. Whitesands Insitu Partnership, a partnership between Petrobank and its wholly-owned subsidiary Whitesands Insitu Inc., owns 75 net sections of oil sands leases in Alberta, 36 sections of oil sands licenses in Saskatchewan and operates the Whitesands project which is field-demonstrating Petrobank's patented THAI™ heavy oil recovery process. THAI™ is an evolutionary in-situ combustion technology for the recovery of bitumen and heavy oil that integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally. THAI™ and CAPRI™ are registered trademarks of Archon Technologies Ltd., a wholly-owned subsidiary of Petrobank.

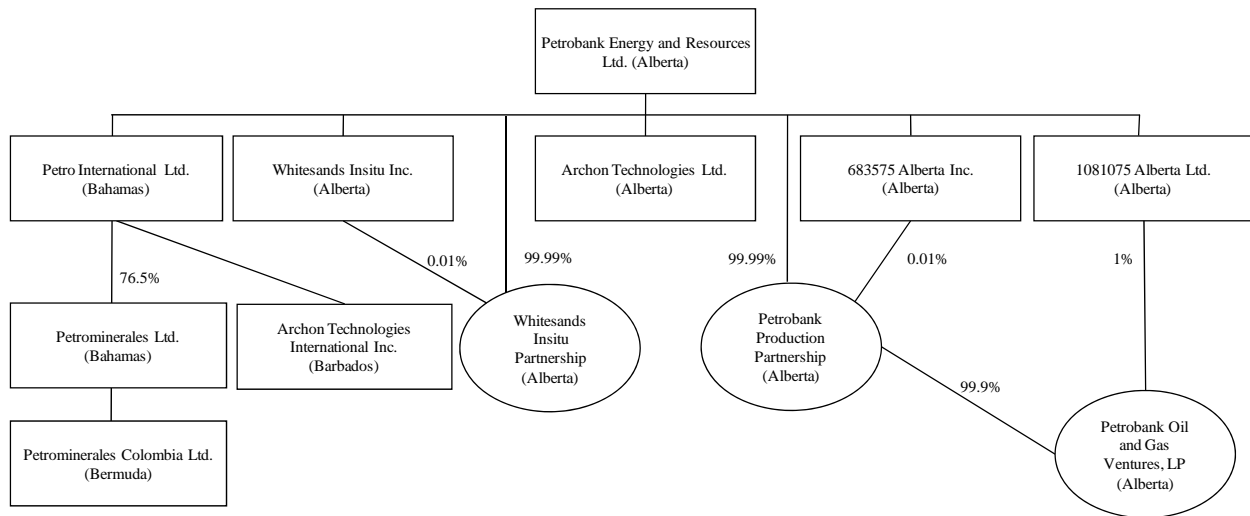
CORPORATE STRUCTURE

The Company was incorporated under the ABCA on December 1, 1983 as "Petrobank Energy Resources Ltd." On September 8, 1986, Articles of Amendment were filed to change the Company's name to "Petrobank Energy and Resources Ltd." On September 8, 1993, the Company filed Articles of Amendment to delete the private company restrictions thereunder. The Company filed Articles of Amendment on March 7, 2000 to create the first series of Preferred Shares designated as Preferred Shares, Series A and on August 22, 2000 to create the second and third series of Preferred Shares designated as Preferred Shares, Series B and Series C (these preferred shares are no longer outstanding). On January 1, 2002, the Company filed Articles of Amalgamation to amalgamate with its wholly-owned subsidiary, Barrington Petroleum Ltd.

Effective December 31, 2007, Petrobank and its wholly-owned subsidiary Whitesands Insitu Inc. formed Whitesands Insitu Partnership. Effective January 1, 2008, Petrobank amalgamated with its wholly-owned subsidiaries Orion Oil Canada Ltd. and Whitesands Insitu Ltd. Effective January 28, 2008, Petrobank amalgamated with Peerless Energy Inc. (see "Acquisitions"). Effective January 1, 2009, Petrobank amalgamated with Denison Resources Holding Corporation, Rocor Resources Inc. and 1424107 Alberta Ltd.

The Company's principal office and head office is located at Suite 1900, 111 - 5th Avenue S.W., Calgary, Alberta, T2P 3Y6. The Company's registered office is located at 3300, 421 - 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

As of the date of this Annual Information Form, the material subsidiaries of the Company, each of which is wholly-owned (except as noted), and their jurisdictions of incorporation or formation are as follows:



THREE-YEAR HISTORY OF THE BUSINESS

Year-Ended December 31, 2006

The Company raised \$33.4 million pursuant to a prospectus offering issuing 2,597,403 common shares.

On March 6, 2006, the Company announced that it had increased its oil sands land base by 33 percent and that initial start up operations were underway at the Whitesands pilot project. Whitesands acquired a total of 15 sections of oil sands leases at a net cost of \$20 million, 11 of which were contiguous with its existing leases, with the remaining four sections in close proximity.

On March 13, 2006, the Ojo de Tigre-1 exploration well on the Joropo Block in the Llanos Basin of Colombia was plugged and abandoned.

On April 12, 2006, the Company advised that production from the Orito 117 and 118 wells contributed to a significant increase in Colombian production, which averaged 2,612 bbl/d in the second quarter of 2006.

On June 29, 2006, the Company closed the initial public offering of common shares of Petrominerales. In connection with the initial public offering, Petrobank sold an aggregate of 2,306,173 common shares of Petrominerales for gross proceeds of approximately \$8.7 million. Following completion of the initial public offering, Petrobank retained an 80.7 percent interest in Petrominerales. Petrominerales commenced trading on the Toronto Stock Exchange on June 29, 2006, under the symbol 'PMG'.

On July 21, 2006, the Company announced that it had completed the Pre-Ignition Heating Cycle on the first well pair at the Whitesands project and commenced air injection.

On November 22, 2006, the Company reported that as a result of a recent five well drilling program the gross working interest contingent recoverable bitumen estimate had increased by 23 percent to up to 658 million barrels on a portion of the 62 sections of oil sands leases owned by Whitesands Insitu Ltd.

On December 22, 2006, the Board of Directors of the Company adopted a Shareholder Rights Plan designed to encourage the fair treatment of shareholders in connection with any take-over offer for the Company.

Also on December 22, 2006, Petrobank completed a bought deal financing consisting of 3,000,000 common shares of Petrobank at a price of \$17.75 per common share and 1,500,000 common shares issued on a flow-through basis at a price of \$23.00 per flow-through share, resulting in gross proceeds of approximately \$87.8 million.

Year ended December 31, 2007

On January 16, 2007, the Company provided an operational update on the ongoing field demonstration of Petrobank's THAI™ technology. Production from the first well pair had increased following facility modifications and Whitesands had commenced air injection and oil production from the second well pair at the Whitesands project.

In the first quarter of 2007, Petrominerales obtained an additional six exploration blocks which brought Petrominerales' exploration holdings to a total of 13 exploration blocks, consisting of 1.5 million acres of operated, 100% working interest lands in Colombia's Llanos and Putumayo Basins.

On March 9, 2007, the Ojo de Tigre-2 well on the Joropo Block in the Llanos Basin of Colombia was cased as a potential oil well.

On March 19, 2007, the Company announced that with respect to the Whitesands assets, McDaniel assigned a recoverable bitumen resource of up to 799 million barrels at March 1, 2007, compared to 658 million barrels estimated at December 31, 2006.

On April 3, 2007, Petrobank issued 4,000,000 common shares of Petrobank at a price of \$21.00 per common share, resulting in gross proceeds of approximately \$84 million.

On April 9, 2007, the Company purchased Crown land in the Bakken formation at Saskatchewan's April 2007 land sale, spending \$59.5 million to acquire 41,800 (41,800 net) acres. The Company further announced that the application of new horizontal fracturing and completion technologies contributed greatly to and increasing Bakken productivity and recovery rates.

On May 1, 2007, Petrobank closed the acquisition of a 50% working interest in certain producing properties in the Viewfield/Stoughton area of southeast Saskatchewan, with extensive undeveloped acreage for \$8.5 million.

On May 4, 2007, Petrobank raised US\$250 million through the private placement of 3% Notes due 2012. See "*Description of Capital Structure – Convertible Notes*".

On June 11, 2007, the Company closed the acquisition of all of the shares of its Whitesands Insitu Ltd. subsidiary previously held by minority shareholders, increasing Petrobank's ownership of Whitesands Insitu Ltd. from 84% to 100%, for \$120 million (see "*Heavy Oil Business Unit Overview*").

In the second quarter of 2007, Petrominerales announced that the Mapuro-1 and the Casanare Este-1 wells were plugged and abandoned.

On June 18, 2007, the Company announced that air injection commenced on our third THAI™ well pair at the Whitesands project.

In June, Petrominerales completed drilling and logging operations at the Corcel-A1 exploration well on the Corcel Block in the Llanos Basin. The Corcel-A1 well spudded on April 7 and reached a total depth of 12,000 feet on June 14. An extended production test commenced on September 7. On October 17, the Corcel-A2 well reached total depth and was cased as a potential oil well. In November, Petrominerales commenced an extended production test of the Corcel-A2 well.

On September 13, 2007, Petrominerales issued 5,060,000 common shares at US\$12.05 per share for gross proceeds of approximately US\$61 million.

In the fourth quarter of 2007, Petrominerales completed the Conga-1 exploratory well as a potential oil well on the Las Aguilas Block in the Putumayo Basin.

In the fourth quarter of 2007, Petrobank entered into a THAI™ license agreement and acquired a 50% interest in certain heavy oil lands and related assets in the Peace River region of northwest Alberta owned by Shell Canada Upstream (predecessor by amalgamation with Duvernay Oil Corp. effective December 30, 2008.) See “*Heavy Oil Business Unit Overview - Dawson Project*”.

On November 1, 2007, Petrobank acquired the Sutton Creek License, comprised of a 23,040 acre oil sands licence in Saskatchewan. The licence has a primary term of five years and forms the basis for a possible future expansion of the application of the THAI™ technology into a new potential oil sands resource fairway.

On November 14, 2007, Whitesands received a \$10 million grant, from the Government of Alberta, in the form of a royalty credit for Crown royalties. This program is administered by Alberta Energy’s Innovative Energy Technologies Program.

On November 22, 2007, Petrobank entered into an arrangement agreement to acquire all of the issued and outstanding shares of Peerless by way of plan of arrangement. See “*Acquisitions*”.

On December 6, 2007, Petrominerales raised US\$100 million with a private placement of 3.375% convertible notes due December 2010. In the fourth quarter of 2008, Petrominerales repurchased convertible debentures with a face value of \$18.3 million at a 39% discount.

Year ended December 31, 2008

On January 3, 2008, Petrobank announced the release of Whitesands’ Public Disclosure Document relating to the proposed May River Project. See “*Heavy Oil Business Unit Overview - May River Project*”.

On January 28, 2008, Petrobank closed the Peerless acquisition and Peerless was amalgamated with Petrobank. See “*Acquisitions*” and “*Corporate Structure*”.

In February 2008, Petrominerales’ Casanare Este-2 exploration well was drilled to total depth of 10,570 feet, and was subsequently cased as a potential oil well. The well was subsequently abandoned based on results obtained from the offsetting Castor-1 well.

On March 13, 2008, Petrobank announced that average production in the first quarter of 2008 increased to 22,524 boepd compared to 6,139 boepd in the first quarter 2007, a 267% increase. CBU production increased by 239% to 13,889 boepd and production from the LABU increased by 323% to 8,635 bopd. Petrobank also entered into an arrangement agreement to acquire 100% of the issued and outstanding

shares of Rocor (see “*Acquisitions*”). In addition, Petrobank acquired an entry position on resource plays in the Muskwa and Evie shales of the Horn River Basin in northeast British Columbia.

In the second quarter of 2008, Petrominerales drilled and completed two exploration wells on the Mapache Block (Mapache-1 and Mirasol-1 (formerly Mapache-2)) as potential oil wells.

On August 13, 2008, Petrobank announced that production increased to over 34,500 boepd mainly due to significant production additions from the Corcel-A4 and C1 wells in Colombia and our ongoing Bakken development drilling program. In addition, the Company announced that the boards of directors of Petrobank and Petrominerales both approved normal course issuer bids (the “NCIBs”) (see “*Normal Course Issuer Bids*”).

On September 22, 2008, the Company announced the world’s first CAPRI™ in-situ catalytic production well (P3B) at our Whitesands project.

On October 2, 2008, the Company announced that it successfully closed the previously announced acquisition of Rocor for total consideration of approximately \$53 million, comprised of 699,183 Petrobank common shares and \$26.5 million in cash (see “*Acquisitions*”).

On November 21, 2008, Petrobank entered into a royalty, technology license and a joint operating agreement with True Energy Trust to apply Petrobank’s patented THAI™ heavy oil recovery technology on portions of True’s Kerrobert heavy oil property in Saskatchewan (see “*Heavy Oil Business Unit Overview*”).

On November 28, 2008, the Company announced that the ERCB approved a three well expansion at Petrobank’s Whitesands site.

In November 2008, Petrominerales entered into an agreement to acquire a 55 percent interest in the 2.6 million acre Block 126 in the Ucayali Basin of Peru (see “*Peru*”).

In late November 2008, Petrominerales’ drilling and completion operations at the Orito field were suspended temporarily, due to a general strike in the Putumayo region of Colombia. Operations resumed on January 6, 2009.

On December 18, 2008, Petrobank announced that it filed its application for the May River Project with the ERCB and Alberta Environment. The May River Project is Petrobank’s 10,000 bopd THAI™ commercial demonstration project to be developed on our Whitesands Leases located two kilometres from the current Whitesands pilot project site.

In December 2008, Petrominerales was granted two contiguous blocks in the Llanos Basin north of Corcel, Block 25 and Block 31, on trend with the “world-class giant” Cusiana-Cupiagua. The award of blocks 25 and 31 brought Petrominerales’ aggregate exploration contract holdings to 16 exploration blocks in Colombia, consisting of 1.9 million acres of 100 percent working interest in operated lands in Colombia’s Llanos and Putumayo basins.

On December 24, 2008, Petrobank completed a private placement of 285,795 common shares issued on a flow-through basis, at a price of \$33.00 per share, resulting in gross proceeds of \$9.4 million.

ACQUISITIONS

On January 28, 2008, Petrobank acquired Peerless Energy Inc. (“**Peerless**”) for \$338.8 million, including net debt assumed. At the time of acquisition, Peerless was producing approximately 5,600 boepd, of which approximately 3,400 bopd was Bakken light oil strategically located within Petrobank’s core properties in southeast Saskatchewan. Peerless’ proved plus probable plus possible reserves totalled 18.7 million boe and the net present value discounted at 10% (before tax) totalled \$445.6 million at December 31, 2007. Production and financial results for Peerless have been included in Petrobank’s results starting January 28, 2008. On April 22, 2008, Petrobank filed on SEDAR Form 51-102F4 (Business Acquisition Report), with respect to our acquisition of Peerless.

On October 2, 2008, Petrobank acquired Rocor for \$52.7 million, net of working capital assumed. Rocor’s assets are focused on the Montney formation in northeast British Columbia and included 14 sections of land with two producing vertical wells, and a five mmcf per day gas plant. Production and financial results for Rocor have been included in Petrobank’s results starting October 2, 2008. Petrobank did not, nor was required to, file Form 51-102F4 (Business Acquisition Report) with respect to our acquisition of Rocor.

OVERVIEW OF THE BUSINESS AND PRINCIPAL PROPERTIES

Canadian Business Unit Overview

Key properties of Petrobank’s Canadian Business Unit include the following:

Bakken Formation, Southeast Saskatchewan

The Bakken formation is found in the Williston Basin, underlying much of North Dakota, eastern Montana and extending up into southern Saskatchewan. Unlike the conventional Mississippian oil resources in this area of Saskatchewan which accumulate in distinct reservoirs, the Bakken is an extensive regional resource play with the oil contained mostly in siltstones and thin sandstone reservoirs with low porosity and permeability. Bakken oil is rich in natural gas and associated natural gas liquids, and a facility program is underway to capture this additional revenue stream.

Following the success of Petrobank’s Bakken drilling program in late 2006, we proceeded, in early 2007, to drill a series of exploration wells to extend the boundaries of the Bakken resource play, prior to the major April 2007 Saskatchewan Crown land sale. At the April 2007 Crown land sale, Petrobank spent \$59.5 million to acquire 41,800 net acres of land in the Bakken play. Petrobank’s Canadian Business Unit continued to build critical operating mass in Bakken play in early 2007, when we acquired a 50% working interest in producing properties in the Viewfield/Stoughton area of southeast Saskatchewan from a third party.

Our initial gas conservation and oil facility was completed at Innes in late 2007. In 2008, three new facilities at Viewfield, Creelman, and Freestone were connected to our main Midale plant through 100 kilometres of new pipelines. Together our facilities are conserving more than 6.5 mmcf/d of natural gas plus associated natural gas liquids and allow us to maintain low operating costs while improving our overall project economics. All of these facilities are designed around a proactive approach to conserve liquids-rich natural gas associated with our high-value Bakken light oil production.

The Bakken formation was Canadian Business Unit’s primary focus in 2008. In January 2008, we closed the acquisition of Peerless (see “*Acquisitions*”). We operated an average of eight rigs through the year, and at times had up to 10 rigs running to execute our development drilling program, which resulted in

approximately three new wells being added per week. Our operational expertise was also refined through 2008, compressing the time from spud to on-stream for our wells, inclusive of the multi-stage fracture stimulation to 35 days. In 2008, we drilled 226 (187.5 net) oil wells on our Bakken lands, surpassing our internal target of 154 net operated wells, with a 99% success rate. Of the wells drilled, 166 (161 net) were operated wells and 60 (26.5 net) were non-operated wells.

The Company's Bakken land base, as of December 31, 2008, totals 270 (236 net) sections with an average 87% percent working interest. CBU production increased 225% to 17,775 boepd in 2008 from 5,476 boepd in 2007 and proved plus probable reserves increased by 95% year-over-year to 59.5 million boe. In 2008, Bakken production was 14,982 boe/d, representing 84% percent of the Company's Canadian Business Unit production during 2008.

Monias – Northeastern British Columbia

In October 2008, through the acquisition of Rocor, we acquired a prospective position in the Montney tight gas play at Monias in northeastern B.C. We have a 100% working interest in 14 contiguous sections of land, and a 5.0 mmcf/d gas plant.

In December 2008, we drilled our first Montney horizontal well, and in February 2009 we performed seven multi-stage fracture stimulations in the upper portion of the 135 metre thick Montney interval. The well flow tested at initial rates in excess of 7.5 mmcf/d plus 180 barrels of natural gas liquids per day. The consistent geology across our 14 sections of land establishes a 55-well inventory of prolific Montney drilling locations. Our next steps will be to install additional compression to increase our plant capacity to 10.0 mmcf/d and then drill another well later in 2009. Our independent reserve evaluators have only assigned reserves to our initial well as at December 31, 2008.

Horn River – Northeastern British Columbia

A resource play where the Company intends to apply our innovative completion experience is in the Horn River Shale Basin, north of the Montney play in northeast B.C. As this emerging play has developed, we began to build an acreage position, which now encompasses 65 sections (43,428 acres) of 100% working interest lands and 14 sections of 15.5% working interest lands. Our first horizontal evaluation well initiated drilling in late February 2009 in an area with all-season access close to the Alaska Highway. The majority of the basin is characterized by a short three-month operating season (January to March) due to the presence of thick muskeg. All-season access at this first location will allow us to complete the multi-stage fracture stimulation during the second quarter of 2009. Our immediate focus will be on drilling test wells and developing a multi-year inventory of drilling locations in the Muskwa and Evie shales.

No reserves have been assigned to our Horn River asset base as at December 31, 2008.

Torquay, Southeast Saskatchewan and Southwest Manitoba

Petrobank is evaluating the potential of the Torquay formation, another siltstone play similar to the Bakken, however, it is found in deeper Devonian-aged rocks. To date, Petrobank has drilled seven vertical wells and one horizontal well (100 percent working interest) to test the play, which yielded high initial rates of production but with steep declines. We are currently evaluating optimal drilling and completion techniques to obtain maximum recovery rates. Our land base in the Torquay area includes 5.5 sections of land that the Company considers prospective. In addition, we hold other lands in the region with as yet undefined potential.

Jumpbush/Milo, Alberta

Petrobank's Jumpbush property is predominantly located on the Siksika First Nation, approximately 100 kilometres east of Calgary, Alberta. The Company is operator and 70 percent working-interest partner with Siksika Energy Resources Corporation (SERC). The Company believes that Jumpbush provides a unique opportunity as it represents a large island of underdeveloped acreage predominantly on the Siksika Nation, surrounded by non-reserve lands that have been developed in recent years. The Company holds a portion of these surrounding lands at 100 percent working interest.

As at December 31, 2008, Petrobank's land base in this area totals 56,908 gross acres (40,243 net acres).

The Jumpbush program is primarily a conventional shallow gas play in the Belly River and Medicine Hat formations. The Belly River formation has several zones capable of natural gas production. Petrobank has successfully applied 3D seismic to identify prolific Belly River gas horizons. By contrast, the deeper Medicine Hat formation and the Milk River formation both contain a single gas-saturated, low permeability sandstone of variable productive capability, which is encountered in almost every well drilled.

There was no drilling activity at Jumpbush during 2008. The Company's production averaged 865 boe/d at Jumpbush during 2008, 98 percent of which was natural gas. In 2008, production from Jumpbush represented five percent of the production attributable to Petrobank's Canadian Business Unit.

Northwest Alberta Exploration

Petrobank is balancing its lower risk activities with higher impact exploration potential. During 2008, Petrobank continued to acquire Crown lands across identified exploration plays in northwest Alberta with the main targets being light sweet oil and natural gas opportunities in stacked horizons. In 2008, a step-out exploration well was drilled at Cornwall and subsequently abandoned as follow-up to a successful exploration well drilled late in 2007 which tested gas at 6.5 mmcf/day with 200 barrels per day of condensate.

Heavy Oil Business Unit Overview

The Heavy Oil Business Unit is focussed on developing heavy oil resources utilizing the proprietary THAI™ and CAPRI™ technologies. These technologies can be used in a wide range of oil sands and conventional heavy oil reservoirs worldwide. At our Whitesands project, in the Athabasca oil sands in Canada, the Company has been producing partially upgraded bitumen since 2006. During the fourth quarter of 2008, the Company filed a regulatory application for the May River project, a 10,000 barrel per day commercial project which is the first phase of a potential 100,000 barrel per day project on our Whitesands lands.

In 2007, the Company entered into a THAI™/CAPRI™ license agreement with Duvernay Oil Corp., which was subsequently acquired by Shell Canada Limited, to develop a project in the Peace River region of the Canadian oil sands. An additional joint venture and THAI™/CAPRI™ license agreement was signed in late 2008 with True Energy Trust for a conventional heavy oil project at Kerrobert Saskatchewan. Through the Company's wholly-owned subsidiary Archon Technologies Ltd., additional patents have been granted and several are pending for enhancements to THAI™ and CAPRI™ extending the term and broadening the intellectual property base of our technologies.

THAI™ Technology

THAI™ is the Company's patented evolutionary in-situ combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI™ integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally. During the process a high temperature front is created from the combustion/gasification a portion of the oil in the reservoir which reduces the viscosity, mobilizing the remaining oil allowing it to flow by gravity to the horizontal production well. The combustion front sweeps the oil from the toe to the heel of the horizontal producing well, recovering up to an estimated 70-80 percent of the original-oil-in-place while partially upgrading the crude oil in-situ. The THAI™ and CAPRI™ technologies were acquired in 2003 by Petrobank and are held in Petrobank's wholly-owned subsidiary, Archon, which controls all intellectual property rights to the THAI™ process and related enhancements, including the patented CAPRI™ technology which offers the potential for further in-situ upgrading through the use of a well-bore integrated catalyst.

THAI™ has many potential benefits over other in-situ recovery methods, as noted below:

Operational and economic benefits

Higher potential resource recovery, projected at 70 to 80 percent of bitumen-in-place in the oil sands based on laboratory tests and field scale numerical simulation.

- Ability to operate in lower quality reservoirs inaccessible using other steam-based recovery processes
- Lower capital and operating costs
- Shorter construction period
- Negligible consumption of natural gas and water
- Partially upgraded bitumen
- Reduced diluent requirements for transportation
- Energy self-sufficient through the utilization produced gas for power generation

Environmental benefits

- In addition to operational and economic benefits, the THAI™ process provides benefits in terms of reducing the impacts of resource development impacts on the environment.
- Lower greenhouse gas emissions
- Minimal use of groundwater and natural gas
- Reduced surface facilities footprint
- High quality produced water with potential industrial uses
- CO₂ capture ready

THAI™ Process Steps

Pre-Ignition Heating Cycle

At start-up the horizontal and vertical wells are steamed for a short period of time to warm the horizontal well and to create mobility around the vertical well to facilitate air injection. Work is being done to try to eliminate the steam from the PIHC.

Combustion Initiation

Air is injected into the reservoir, auto-igniting the oil creating a high temperature combustion zone (over 700°C). The hot combusted air contacts the cold oil in front of the combustion zone causing the lighter oil fraction to be mobilized and the heavier fraction to be deposited as hydrocarbon coke onto the reservoir sand. The continuous deposition of coke provides the fuel for the ongoing combustion reaction. The light oil and vaporized reservoir water are swept into the horizontal well and to surface by the combusted air.

Steady State

As air injection continues, the oil drainage front broadens and a continuous air bank is established with production stabilizing at rates of over 500 bbl/day based on reservoir models. At steady state, the shape of the oil drainage front is constant, enabling control of the oxygen flux and assuring that the high-temperature oxidation process predominates.

End State

Once the front edge of the drainage volume reaches the heel of the horizontal producer, the next set of follow-on horizontal wells can be drilled. The reservoir is already preheated and the process can continue on in the steady state phase at peak production rates without additional start-up phases. The region behind the burning front is swept of oil, demonstrating why high recovery factors are expected with the THAI™ process.

THAI™ Applicability in the Canadian Oil Sands

The geology of the Canadian oil sands resource is variable and is a major influence in the performance of any recovery technology. The major variables include: the presence of bottom water, top water and/or top gas, which can act as thief zones for heat; large shale lenses that act as barriers for steam migration; the thickness of the bitumen zone; and lower pressure reservoirs. Several technologies rely on steam to heat and soften the bitumen underground allowing it to flow to production wells. Both CSS and SAGD are operate best in relatively homogeneous oil sands reservoirs, which is only about 10 percent of the resource base, and can only recover 20-50 percent of the bitumen in place.

THAI™ has the potential to recover up to 70-80 percent versus 20-50 percent from the current steam-based in-situ technologies. THAI™ could also be applied to previously steamed reservoirs to recover residual bitumen and has the potential to operate in poorer quality reservoirs as it is less impacted by the geologic variables found in the oil sands. Thinner reservoirs (less than 10 metres) can be a target for THAI™ as only one horizontal well is required compared to two horizontal wells with SAGD. THAI™ is not as sensitive to the presence of top or bottom water, which act as heat thief zones, nor is as sensitive to the absence of top gas that provides some reservoir pressure.

One of the main geological variables of the oil sands is large shale lenses which act as barriers for steam migration. These shale lenses are less of a concern with THAI™ as the process creates its own pressure regime and operates at very high temperatures, allowing heat to penetrate around these potential barriers.

Canadian Oil Sands

The Canadian oil sands are the world's largest accumulation of hydrocarbons. Located in north eastern Alberta, the oil sands underlie approximately 140,000 square miles and contain bitumen, a thick tar-like

hydrocarbon which requires significant upgrading or diluent to be marketable. The Company's Whitesands assets are situated in the heart of the in-situ oil sands development fairway.

Challenges of the Canadian Oil Sands

The bitumen contained in the Canadian oil sands is immobile and is often produced through open-pit mining where it is encountered close to the surface or, where the bitumen is too deep to mine, through the addition of steam heat into the reservoir.

To date, in-situ recovery using SAGD and CSS has been utilized to inject steam to heat the reservoir and mobilize the bitumen so that it can flow to a production well. These steam-based processes can typically recover 20 to 50 percent of the bitumen in place. SAGD involves drilling one horizontal well near the bottom of the reservoir and a second horizontal steam injection well 3 to 5 metres above the production well. The steam rises, mobilizing the bitumen which drains into the lower horizontal well and is pumped to surface. CSS uses one vertical well to inject steam for a period of time, after which the mobilized bitumen and condensed water is pumped to surface using the same well. In CSS the steam is injected at a high pressure, often high enough to fracture the reservoir rock, and the steam injection and oil production is repeated over many cycles. Steam processes are energy intensive with high environmental impact as large amounts of water are required to generate the steam and produces associated emission of significant volumes of greenhouse gases from the burning of natural gas and other hydrocarbon fuels.

THAI™ Applicability in Conventional Heavy Oil

Conventional heavy oil is mobile, lighter than bitumen, and production processes are similar to light oil where the oil is pumped cold. Recovery factors for conventional heavy oil are very low with 80 to 90 per cent of the original oil-in-place being unrecovered. These types of resources occur worldwide and represent over three trillion barrels of oil-in-place, much of which may be recoverable using THAI™.

Whitesands Project

Petrobank, through Whitesands, has a 100 percent working interest in 62 sections (39,680 net acres) of oil sands leases, referred to herein as the Whitesands Leases, located at Townships 76-78 Ranges 8-10 W4M near the Hamlet of Conklin, Alberta. The oil sands bitumen deposit is contained within the cretaceous-aged McMurray filled valley sandstone at a depth of 350 to 400 metres. The Whitesands Leases are Crown leases with 15-year primary terms. Certain of the leases comprising the Whitesands Leases expire in 2015, with additional expiries occurring in 2017 and 2021. With commercial development the Whitesands Leases can be held by Whitesands indefinitely, as such, the Company does not expect to allow any of the lands comprising the Whitesands Leases to expire. The nearest commercial production to the Whitesands Leases is at the EnCana Christina Lake SAGD project approximately 24 kilometres east of the Whitesands Leases. Other commercial SAGD projects in operation near the Whitesands Leases include Devon Energy Ltd.'s Jackfish project, MEG Energy Corp.'s Christina Lake project, Statoil's Kai Kos Dehseh project, and Nexen Inc. and OPTI Canada Inc.'s Long Lake project.

Whitesands is utilizing THAI™ in-situ heavy oil recovery process in the oil sands resource on the Lands. To this end, applications to conduct a THAI™ project on the Lands were filed with the AEUB and AENV in October 2003, and in February 2004 the Whitesands project received approval from the AEUB and AENV. The approval was the culmination of rigorous technical and environmental scrutiny by the regulatory authorities.

The Whitesands pilot project was designed around three well pairs producing to a central facility. Air injection commenced on the first well pair in July 2006. Air injection on the second well pair was

initiated in January 2007 and on the third pair in June 2007. The wells each demonstrated the same start up characteristics. Modifications to the surface facilities, including enhanced sand handling capability, as well as wellhead and choke enhancements, have improved the operating efficiencies. De-bottlenecking was completed to improve the efficiency and capacity of the surface facilities.

One of the expected benefits of THAI™ is partial upgrading in-situ. We have consistently produced upgraded bitumen to between 10 and 14 degrees API from a native API of 7.8 degrees. Viscosity is also consistently reduced from a native viscosity of approximately 500,000 centipoises to several thousand centipoise and lower in the more upgraded production. One of the unique aspects of the oil produced by the THAI™ process is the lack of difficult emulsions and there is a clean oil/water separation eliminating the need to add diluent at surface to achieve a clean oil water separation.

On April 1, 2005, the Company announced that TPC had committed to invest up to \$9.0 million towards the development and field demonstration of the THAI™ technology at the Whitesands project. Upon commercialization of THAI™ technology, TPC will be entitled to a royalty based on three separate revenue streams. The first stream is based upon 3 percent of Whitesands project revenue earned after January 1, 2006 with initial payments due May 1, 2010. The second stream is based on 0.6 percent of Whitesands revenues (excluding pilot project revenues) earned after January 1, 2009 with initial payments due May 1, 2010. The third stream is based on 3 percent of all third party THAI™ licensing revenues earned after January 1, 2008 with initial payment due May 1, 2009. If, as of December 31, 2017, the cumulative royalty paid from the three royalty streams has not reached or exceeded \$26.2 million, royalty payments will continue until \$26.2 million has been paid or until December 31, 2022, whichever occurs first.

On June 11, 2007, the Company closed the acquisition of all of the shares of its Whitesands Insitu Ltd. subsidiary previously held by minority shareholders, increasing Petrobank's ownership of Whitesands Insitu Ltd. from 84% to 100%, for \$120 million. The acquisition was funded entirely by cash on hand. This acquisition was completed pursuant to the terms of the Unanimous Shareholders Agreement governing the original investment. The shares of Whitesands Insitu Ltd., previously held by these minority shareholders through their original investment, were purchased by the minority shareholders in April 2005, at a cost of \$23.7 million in exchange for the 16% interest in Whitesands Insitu Ltd. and three million common shares of Petrobank.

On November 14, 2007, Whitesands received a \$10 million grant, from the Government of Alberta, in the form of a royalty credit for Crown royalties. This program is administered by Alberta Energy's Innovative Energy Technologies Program ("IETP"). The IETP represents a \$200 million commitment over five years by Alberta Energy to provide royalty adjustments to a number of specific pilot and demonstration projects that use innovative technologies to increase recoveries from existing reserves and encourage responsible development of oil, natural gas and in-situ oil sands reserves. IETP is also designed to provide funding for industry to find commercial technical solutions to the gas over bitumen issue that will allow efficient and orderly production of both resources.

In December 2007, the Company completed a 4D seismic survey over the current Whitesands project site, which provides confirmation of the combustion zone development. A further 4D seismic survey was completed in December 2008 and this survey also confirmed the process in the reservoir is progressing from the toe of the production well to the heel.

The Company drilled P3B on the Whitesands Leases late in the second quarter of 2008 and completion operations commenced on the well in late July, 2008. This well was designed to demonstrate the additional upgrading potential of our CAPRI™ process which places an active catalyst bed between two concentric slotted liners. In laboratory tests, CAPRI™ has achieved an upgrading effect of seven degrees

API in addition to the upgrading effect resulting from the THAI™ process. The P3B well also incorporates our narrower slot design, intended to significantly reduce sand production from the McMurray sandstone reservoir typically encountered at the Whitesands Leases.

Since commencing production on the P3B well, the well has exhibited negligible sand production proving the effectiveness of the new liner design. The current degree of oil upgrading and the produced gas analysis from P3B are consistent with the P1 and P2 wells, indicating high temperature combustion. Produced oil quality is consistently averaging approximately 12 degrees API, compared to the native eight degree API bitumen in-situ. We continue to recover a light oil condensate stream in the secondary separators that is being carried in the vapour phase by the overhead gas system and condensed out in the secondary separators. This lighter oil can be over 30 degrees API and recent analysis indicates that this stream could be up to 10 percent of the total produced hydrocarbons. This lighter oil component further demonstrates significant in-situ thermal cracking and the potential for co-production of other high-value by-products.

In P1 and P2 we have started to see a reduction in produced sand through the de-sand vessels, which has resulted in improved on-stream factors and the wells have had periods of high productivity, up to 400 bopd. Despite these minor operational improvements, these wells still pose major operational challenges and as a result we plan to either re-complete them with narrower slotted liners or drill at least one replacement well. Regulatory approval for our expansion at Whitesands was received late in the fourth quarter and in anticipation of this approval we positioned ourselves to immediately execute the project. However, we have decided that there is little benefit to be gained from significantly expanding the Whitesands site. We have decided to cost-effectively convert Whitesands into a modified three to four well THAI™ and THAI™/CAPRI™ demonstration site.

May River Project

The May River Project is the commercial development of Petrobank's leases (including the Whitesands project) west of Conklin, Alberta utilizing THAI™. The May River design builds on the experience gained from the Whitesands pilot plant and is intended to be built in phases, with initial production capacity of 10,000 barrels of THAI™ oil per day with ultimate capacity of 100,000 barrels.

The regulatory application for May River's first phase was filed with the Energy Resources Conservation Board and Alberta Environment at the end of 2008. The application has been deemed complete and is now moving through the regulatory process.

The front end engineering and design for the project began in the fourth quarter of 2008. The design incorporates power generation utilizing low energy produced gas, sulphur recovery, is CO₂ capture ready, and will be a net water producer rather than a water user, making the May River project a leading environmentally sustainable process for oil sands and heavy oil development. The Project is utilizing a modular approach that is designed to be installed and operated on heavy oil projects world-wide.

Glover Project

In the second quarter of 2007, we acquired the Glover Lease. The Glover Lease located approximately 6.5 kilometres south of the Whitesands Leases. These leases will be further evaluated in the future as our focus will be on Whitesands in May River areas in the Athabasca oil sands.

Dawson Project

The Company acquired a 50% interest in the Dawson Property and entered into a license and royalty agreement with Duvernay Oil Corp., with respect to our first Alberta-based, third party THAI™ license. Our partner is now Shell Canada Limited who acquired Duvernay Oil Corp. in August 2008. The project is located near Peace River Alberta and will be developed in the Bluesky formation. The upper portions of this formation contain 11 degree API heavy oil, comparable to other conventional heavy oil reservoirs throughout western Canada. The project scope consists of two well pairs and our simplified facility design. The Company and Shell have an area of mutual interest in certain lands surrounding the Dawson Property. In August 2008, a stratigraphic well was drilled on the project site that will be used as a thermal observation well during the project's operating phase.

Kerrobert Project

Late in the fourth quarter of 2008, we entered into royalty, technology license and joint operating agreements with True Energy Trust to apply Petrobank's patented THAI™ heavy oil recovery technology on portions of their Kerrobert heavy oil property in west central Saskatchewan.

Under the agreements, Petrobank will initially earn a 50% working interest in three sections of land in the Kerrobert Mannville heavy oil pool. Subject to regulatory approval, Petrobank and True will develop a two-well project to demonstrate the THAI™ technology in this 20+ metre thick conventional heavy oil reservoir. Petrobank will earn an additional ten percent gross overriding royalty on True's share of all THAI™ production following a threshold reserve recovery.

Petrobank will also earn a 50% working interest in 10 additional sections of True lands upon the expansion of the initial THAI™ project or development of another project on these lands. In addition, Petrobank and True established an area of mutual interest over 30 additional sections of land to jointly develop additional THAI™ projects.

Sutton Creek Project

In the third quarter of 2007, we acquired a township of land comprised of 36 square miles (23,040 acres) with oil sands potential at Sutton Creek, Saskatchewan. This new land position is located within a new and promising Saskatchewan oil sands fairway. In 2008, we acquired 35 kilometres of 2D seismic on our 23,040 acre oil sands lease in northwest Saskatchewan.

Intellectual Property

The Company indirectly owns the patents and other intellectual property rights to the THAI™ and CAPRI™ technologies (the "Technologies") through Petrobank's wholly-owned subsidiary, Archon. Whitesands has royalty free use rights to the Technologies and any future third-party (non-Petrobank) licensing royalties generated by Archon are subject to a 17.5 percent net profits interest payment (see "*Interest of Management and Others in Material Transactions*"). THAI™ is patented in Canada (patent number 2176639, expiring May 15, 2016) the United States (patent number 5,626,191 expiring June 23, 2015 and September 4, 2018) and Venezuela (patent number 57853 expiring May 29, 2016). CAPRI™ is patented in Canada (patent number 2255071, expiring December 4, 2018) the United States (patent number 6412557 expiring August 25, 2020) and the United Kingdom (patent number 1060326 expiring December 4, 2018) and Australia (patent number 9914781 expiring June 28, 2019). Each of THAI™ and CAPRI™ have trademark registrations in Canada, the United States, and certain other countries around the world for use in association with the Technologies.

Research and development activities are conducted under two wholly-owned subsidiaries of Petrobank, Archon and Archon Technologies International Inc. Proprietary laboratory facilities were established in 2005 and Archon is playing an increasingly important role in the development of new technologies and enhancements to the THAI™ process, as well as the evaluation of complementary technologies. Ongoing activities include the advancement of CAPRI™ which adds a catalyst around the horizontal production wells to increase the upgrading effect in-situ, concurrent with the THAI™ combustion process. Archon also performs a vital function in the ongoing evaluation of the operation of the Whitesands project by analyzing produced gases, water and oil, as well as generating solutions to operating issues as they arise. This creates valuable operational know-how and intellectual capital in the technologies.

In early 2009, Petrobank's wholly-owned subsidiary, Archon Technologies Ltd., achieved an important milestone with the granting of two new U.S. patents, for previously filed patent applications covering improvements that add novel features to Archon's existing THAI™ and CAPRI™ technologies. These new patents enable pressure and temperature control in the horizontal producer as well as the co-injection of oxygen and CO₂ that combines the benefits of thermal and solvent flooding. In addition, these patents extend the life of our existing intellectual property to 2026. Three other patent applications are pending, covering a "Heel-to-Toe" combustion design, our novel well design and catalyst placement for CAPRI™, and downhole solvent injection. The Archon suite of patents are filed under the Patent Convention Treaty for worldwide coverage. Archon continues to develop additional patentable intellectual property to further enhance and expand the effectiveness of our core THAI™ and CAPRI™ technologies.

Latin American Business Unit Overview

Petrominerales, the Company's 76.5% owned subsidiary, is an exploration and production company operating at the forefront of Colombia's oil and gas industry. Five years ago, the Colombian government introduced a compelling new fiscal and land contracting regime. Under the new regime, Petrominerales began accumulating exploration blocks and is now one of the country's largest land holders with 18 blocks spread across three prolific hydrocarbon basins. Petrominerales was one of the first exploration companies in the country to use 3D seismic as a primary exploration tool, and in 2007, we drilled a major discovery at Corcel. With rapid development of Corcel, Petrominerales is now Colombia's largest producer from exploration blocks under the new fiscal and land contracting regime. Corcel is only one of many exploration plays being pursued by Petrominerales in the largely under-explored basins of Colombia and now, Peru.

As one of the largest land holders in Colombia, Petrominerales has identified key areas to focus our resources and the talents of our people. There are three pillars to our operating plan:

- *Near-term development* – rapid development of our major Corcel discovery, as well as cost-effective, low risk activities in development projects at our Orito and Neiva fields;
- *High-impact exploration* – selecting basins in both Colombia, and now Peru, which are in the early stages of development, but with excellent prospectivity for large reserve accumulation;
- *Heavy oil* – a longer-term strategy, Petrominerales is starting to explore in Colombia's heavy oil belt, which has potential for future development. Petrominerales plans to be at the forefront of the expansion of the Colombian heavy oil industry through the application of technology. We are targeting large accumulations of heavy oil and offer world-class exploitation expertise including the opportunity to deploy the THAI™ technology in Colombia. THAI™ has significant operational and environmental benefits over other processes and represents a step change in recovery efficiencies. Petrominerales has the exclusive rights for the application of the technology in Colombia.

Principal Properties in Colombia

IPC Contracts

Petrominerales has IPCs in two fields in southwestern Colombia, Orito, in southern Colombia's Putumayo Basin, and Neiva, in the Upper Magdalena Valley Basin, in each case in partnership with Ecopetrol. Each IPC provides that Petrominerales will share in a portion (initially 79 percent in the case of the Orito Block and 69 percent in the case of the Neiva Block) of the incremental production, above an established baseline production curve, generated by its development activities. Each IPC's established baseline of production corresponds to the decline curve forecast based on the field's original production history. Working interest production is subject to an eight percent royalty paid to the government

Orito Field

The Orito Field, the largest in southern Colombia's Putumayo Basin, has extensive field infrastructure, good seismic control and connection to an under-utilized export pipeline with deep water loading facilities, enabling fiscalization of incremental oil production. Pursuant to the IPC, Petrominerales gains access to all existing infrastructure and data, while Ecopetrol participates in any incremental upside Petrominerales generates over the life of the contract, which terminates in June 2023. The Orito IPC covers 42,492 gross acres.

The Caballos formation is a reservoir containing four major sand packages and is interpreted to have a strongly tilted oil-water contact that varies from a depth of 5,200 feet sub-sea in the northern part of the field to 6,200 feet sub-sea in the south. This aquifer provides pressure support to the Caballos reservoir as evidenced by relatively unchanged pressures since 1980. In addition, the Caballos reservoir fluid is compositionally graded, ranging at original conditions from a conventional black 29° API oil at structurally low positions, increasing to approximately 45° API oil with decreasing depth, and culminating in a gas-condensate region at the very top of the reservoir. The complex fluid combined with the tilted contact and structural nature of the reservoir results in a system that has several drive processes occurring simultaneously. "Combination drive" reservoirs (water drive, solution gas drive, and gas cap expansion) tend to exhibit high recovery efficiencies that can reach over 40 percent of the original-oil-in-place. Cumulative total production from the Caballos zone of approximately 192 Mmbbl is considerably below average for a field of this type. To enhance current production, Petrominerales is employing a combination of late-stage primary recovery techniques, such as drilling in-fill wells, changing from gas lift to electric submersible pumps, and re-completing wells to enhance oil inflow.

As at December 31, 2008, the Orito field had produced just over 232 Mmbbl, including approximately 192 Mmbbl from the Caballos zone, the most significant of three reservoirs at Orito. The majority of Petrominerales' expenditures to date have targeted the Caballos zone. Petrominerales also plans to complete testing the Villeta formation found in the Conga-1 exploration well drilled on the neighbouring Las Aguilas Block, and has initiated a pilot water flood in the shallower Pepino zone. Petrominerales' management believes that the Orito field offers numerous opportunities to create value through in-fill drilling, field extension, facilities upgrades, secondary recovery and other enhancement techniques proven in Canada and elsewhere.

In 2008, gross field production at Orito averaged 5,994 bbl/d and baseline production averaged 2,265 bbl/d, resulting in average incremental production of 3,729 bbl/d (2,946 bbl/d working interest to Petrominerales before deduction of an eight percent royalty). The baseline production forecast is:

Orito Field Baseline Production Forecast	
Year	(bbl/d)
2009	2,337
2010	2,222
2011	2,121
2012	2,022
2013	1,934
2014	1,855
2015	1,781
2016	1,712
2017	1,649
2018	1,589
2019	1,534
2020	1,485
2021	1,433
2022	1,384
2023	562

Neiva Field

The Neiva Field in the Upper Magdalena Basin lies approximately 300 kilometres northeast of Orito. Neiva has shallow multi-zone reservoirs facilitating low-risk exploitation drilling. Neiva's reservoir consists of sand-shale sequences totalling up to 1,500 feet of gross pay in the Honda and Doima/Chicoral zones.

Petrominerales holds 2,395 gross acres (1,653 net acres) of land at Neiva under an IPC that expires in June 2023. To the end of 2008, Petrominerales had drilled 12 wells and performed 20 workovers.

In 2008, average daily production in the Neiva field was 2,707 bbl/d and baseline production averaged 2,072 bbl/d, resulting in average incremental production of 634 bbl/d (438 bbl/d working interest to Petrominerales before deduction of an eight percent royalty). The baseline production forecast is:

Neiva Field Baseline Production Forecast	
Year	(bbl/d)
2009	1,948
2010	1,833
2011	1,723
2012	1,619
2013	1,523
2014	1,433
2015	1,348
2016	1,268
2017	1,192
2018	1,121
2019	1,055
2020	992
2021	932
2022	877
2023	348

Exploration Blocks - Colombia

Corcel

Corcel has rapidly progressed from exploration to significant oil production on less than 15% of the block's acreage. There are currently six producing oil wells on the block from three structures, A, C and D. In 2008, average daily production from the Corcel Block was 7,562 bbl/d, the fourth quarter production averaged 13,023 bbl/d and in February 2009 production averaged 21,764 bbl/d. Since inception, the cumulative production from the Corcel Block to December 31, 2008 was 2.4 million barrels from the A structure, 1.0 million barrels from the C structure, and 0.1 million barrels from the D structure.

While the ultimate potential of the block will be defined through long-term testing and additional drilling, Corcel is a significant discovery that has extended the oil-bearing horizons in the Llanos Basin to an area that has not seen exploration activity in recent years.

Production is currently being processed through our Corcel central processing facilities and trucked to seven different offloading stations. The majority of production, 95%, was sold to Ecopetrol and trucked to five offloading stations; Araguaney, Chichimene, Vasconia, Velasquez and Toldado.

Corcel A

The Corcel-A1 well was spud on April 8, 2007 and reached a total depth of 12,000 feet in the third quarter of 2007. A six-month extended production test commenced on September 7, 2007 at initial rates of 4,000 bbl/d.

The Corcel-A2 well was spud on August 25, 2007 and reached a total depth of 12,140 feet on October 17, 2007. Logs indicated total potential net pay of approximately 125 feet of high quality reservoir sands in the Mirador and Guadalupe formations. We initially completed four intervals, with a total of 45 feet of sand, in the Upper and Lower Mirador formations of the Corcel-A2 well. These intervals were initially tested over a 24-hour period and on November 6, 2007 we announced that our Corcel-A2 well came on-stream at rates increasing to 3,100 bbl/d on natural flow. The well was then shut in for pressure build up and was placed on an extended production test commencing November 17, 2007. The well suffered a major casing issue which caused the well to be shut-in in the second quarter of 2008. In 2009 or 2010, we plan to side-track this well and place it back on production.

The Corcel-A3 well was spud on November 21, 2007 and was drilled directionally to a depth of 13,050 feet. Logs indicated that the productive horizons present in Corcel-A1 and Corcel-A2 were present in Corcel-A3. The top of the Mirador zone in Corcel-A3 is approximately 95 feet lower compared to Corcel-A1. An additional 600 feet of geological section was drilled in Corcel-A3 below what was previously thought to be economic basement. During the drilling of the additional section, we encountered sands with oil and gas shows before drilling was terminated and the decision was made to case the well. Three of these new intervals were evaluated, two unsuccessfully. The interval from 12,449 feet to 12,461 feet was perforated and successfully tested 27 degree API crude oil at rates up to 760 bbl/d, with fluctuating water cuts. During 2008 the well was converted to a water injection well to handle produced water from the field.

The Corcel-A4 well was drilled to a targeted depth of 12,465 feet and was brought on production at rates of over 4,500 bbl/d in the Guadalupe and Mirador intervals in the second quarter of 2008.

Corcel C

The Corcel-C1 exploration well was spud on May 23, 2008 and reached total depth of 13,189 feet on July 9, 2008. Logs indicated presence of 77 feet of pay present in the Lower Sand 1 and Guadalupe formations. We perforated 35 feet of the Lower Sand 1 yielding an initial flow rate of 5,200 bbl/d of 19 degree API oil.

The Corcel-C3 well was spud on July 26, 2008 and reached total depth of 13,357 feet on September 1, 2008. Logs indicated presence of 68 feet of pay present in the Lower Sand 1 and Guadalupe formations. We perforated 23 feet of the Guadalupe formation yielding an initial flow rate of 9,700 bbl/d of 29 degree API oil.

Our Corcel-C discovery is significant as it demonstrates the presence of a new play concept in the region. We believe this increases our chance of success on the Corcel-B structure and has expanded our drilling inventory to include the Corcel-G exploration prospect, both of which are analogous play concepts.

Corcel D

The Corcel-D1 exploration well was spud on September 27, 2008 and reached a total depth of 12,350 feet on November 5, 2008. Logs indicated total potential net pay of approximately 102 feet of high quality reservoir sands in the Mirador and Guadalupe formations. The Corcel-D1 well had initial production of 3,800 bbl/d of 22 degree API crude oil with one percent water cut from 35 feet of sand in the Guadalupe formation. Pre-mature water breakthrough in the Guadalupe perforations caused the well to be shut-in in these zones. Based on log and core analysis, the well had an additional 67 feet of net pay in the Mirador and Lower Sand 1 intervals. In January 2009, the well was re-completed in the Mirador formation and was brought on production at 8,770 bbl/d.

The Corcel-D2 exploration well was spud on November 12, 2008 and reached total depth of 12,262 feet on January 3, 2009. Logs indicated presence of 75 feet of pay present in the Mirador and the Guadalupe formations. The liner cementing operation was unsuccessful and attempts to cut and pull the liner from the well were also unsuccessful. The liner was cement squeezed and abandoned and a sidetrack was drilled approximately 15 feet away from the original wellbore where a new seven inch liner was run and successfully cemented. In early 2009, the well was placed on production from 46 feet of pay in the Mirador formation with an initial rate of 4,500 barrels of 26 degree API oil per day at a 50% water cut. The initial 50% water cut is possibly a result of cross flow from water bearing zones encountered in the original wellbore and as a result may not fully reflect the ultimate oil production potential of the Mirador formation.

The Corcel-D3 exploration well was spud on January 31, 2009 and reached total depth of 12,580 feet. Well logs indicate 111 feet of potential net oil pay in the Mirador, Guadalupe and Lower Sand 1 formations and we are casing the well as a potential oil producer.

Corcel Exploration

In 2008, we completed a 120 km² 3D seismic program over the northeastern portion of the Corcel Block adjacent to and on trend with the existing Corcel 3D seismic. The processing was completed in late 2008 and we are currently interpreting the data. Initial indications are that this newly acquired seismic data will allow us to continue to expand our prospect inventory including a number of different play types. All of our 2007 and 2008 drilling locations were picked from our original 3D seismic data set, which covered 15% of the Corcel Block.

Guatiquia

In 2008, we completed a 40 km² 3D seismic program over the Guatiquia Block, immediately southwest and adjacent to the Corcel discovery. We expect to drill our first exploration prospect in 2009, which was identified from the 3D seismic.

Blocks 25 and 31

On December 4, 2008, we were awarded Block 25 and Block 31 at the Colombian Mini Round 2008. Block 25, immediately southwest of and on trend with the “world-class giant” Cusiana-Cupiagua field covers 169,733 acres. Block 31, immediately north of and adjacent to our Corcel Block, covers 163,975 acres.

The first phase work commitments will include shooting 138 km 2D seismic, 55 km² of 3D seismic and drilling one exploration well on Block 25, and acquiring 133 km 2D seismic, 60 km² of 3D seismic and drilling two exploration wells on Block 31.

In aggregate, the blocks currently have 1,315 kilometres of existing 2D seismic from which we have already identified several leads.

The first work commitment phase for both of these blocks is three years. These blocks are subject to the standard ANH contract terms plus a further state participation of one percent of gross production, payable to the ANH. We executed this contract with the ANH on February 16, 2009, and they are subject to the final approval of the Directive Council of the ANH which is expected in due course.

Mapache

On the Mapache Block, two exploration wells, Mapache-1 and Mirasol-1 (formerly Mapache-2), were drilled and completed as potential oil wells in the second quarter of 2008. Subsequent to December 31, 2008, the Mirasol-1 well was prepared for extended production testing. On initial test, the well flowed at an average rate of 1,300 barrels of 34 degree API oil per day, over a 30-hour period from nine feet of high quality sand, in the Upper Carbonera 7 (C7) formation. Following the C7 test in Mirasol-1, the Upper Mirador formation was re-swab tested and stabilized at a rate equivalent to 515 bbl/d of 34 degree API crude. We have installed an electric submersible pump capable of producing 3,500 barrels of fluid per day and have constructed production facilities with an initial capacity of 5,000 barrels of fluid per day. We have begun completion operations at the Mapache-1 well, which appears to have similar potential in the Mirador sands to Mirasol-1. Final rates from our initial twenty four hour flow test at Mapache-1 were 1,400 bbl/d of 34 degree crude oil, at less than 2% water cut.

Casimena

The Mapuro-1 side track well commenced drilling on December 12, 2007 and reached a total depth of 8,760 feet on January 4, 2008. The objective of the well was to test a seismically defined Ubaque formation prospect. However based on petrophysical analyses the well was abandoned. We are planning an 85 km² 3D seismic program in 2009.

Castor

The Castor-1 exploration well was drilled to a total vertical depth of 10,604 feet in the second quarter of 2008 and, based on formation evaluation information, the decision was made to abandon the well. Our

phase 2 commitment includes additional 3D seismic which will be acquired to evaluate an extended portion of the 108,741 acre block before drilling our next Castor exploration well.

Casanare Este Block

The Casanare Este-2 well reached a total depth of 10,570 feet on February 27, 2008. The well was completed as a potential oil well and the first of three potential zones was completed with the drilling rig, but tested 100% water. Originally, we planned to complete the additional horizons in the well with a workover rig but we have now made the decision to abandon the well, based on additional analysis and results from the offsetting Castor-1 well. Before drilling our next Casanare Este exploration well, we plan to acquire additional seismic on the block in 2009.

Jaguar, Altamira A&B

A 3D seismic program was completed covering portions of the Jaguar, Altamira A&B blocks. However, the prospectivity of block as derived from the 3D seismic interpretation did not meet Petrominerales' expectations. We are currently reviewing our strategy for these blocks.

Joropo

On March 6, 2009, Petrominerales notified the ANH of its intention to relinquish 71,130 acres of the Joropo Block, retaining 1,127 acres surrounding the Ojo de Tigre-2 and Ojo de Tigre-3 wells.

Petrominerales drilled an initial test well on this block (the Ojo de Tigre-1 well), in March 2006, which was abandoned due to a lack of commercial hydrocarbons. To extend the term of the license, Petrominerales commenced drilling on a second distinct seismic anomaly in January 2007. The Ojo de Tigre-2 well was initially drilled to a total depth of 8,309 feet and logged and evaluated. Based on Petrominerales' evaluation, and the geological and hydrocarbon indications in this well, a decision was made to side-track to a more favourable bottom-hole location. This second well from the same surface location, Ojo de Tigre-2 Side-Track, was drilled to a total depth of 8,419 feet and was cased as a potential oil well. The well was cored through certain prospective intervals with indications of high quality oil bearing sands, which was confirmed by subsequent logs indicating a primary target, in the Mirador Formation, with net oil pay in excess of 25 feet. A gravel pack was run over the producing interval to prevent sand production that could plug the lifting pump and to guarantee test data given the proximity of the rainy season. The well was tested from March 26 to April 5, 2007 at rates of up to 420 barrels of fluid per day with a water cut ranging between 20 to 30%, showing a permanent improvement in both fluid rate and decreased water cut. The pressure transient analysis showed significant damage presumably associated with the type of completion and will need to be re-tested to fully evaluate the potential of the well.

The Ojo de Tigre-3 well was spud on January 31, 2008 and reached a total depth of 8,324 feet on February 14, 2008. The well was completed in the Carbonera formation. Seventeen feet of C7 sands were perforated, however the well produced 100% water. Upon further evaluation, the presence of poor cement bond in the well is believed to have caused the water influx. A remedial cement squeeze will be required to properly isolate the prospective zones in the well. We also performed a work over in the Ojo de Tigre-2 well to remove the screens and clean out the perforated intervals, and then installed a jet pump completion. The well produced 1,532 barrels of fluid per day, with an 82% water cut, resulting in average production rates of 248 bbl/d, but the well could only be produced during the remainder of the dry season and has now been shut-in. We acquired an additional 30 km² of 3D seismic on the Joropo Block in the second quarter of 2008. No additional prospectivity was interpreted from this seismic survey.

This portion of the Llanos Basin is subject to wet surface conditions during the summer months, and Petrominerales is evaluating alternatives to allow long-term, year-round production of this well. Successful development of this discovery will most likely include upgraded surface access, which would allow for year-round production.

Llanos Basin Heavy Oil Blocks (Rio Ariari, Chiguiro Oeste and Chiguiro Este)

The 576 km of 2D and 62 km² of 3D seismic data acquired over our Rio Ariari, Chiguiro Oeste and Chiguiro Este heavy oil blocks has been interpreted and we have identified an initial 14 prospects. On Rio Ariari, we plan to acquire an additional 50 km² of 3D seismic in 2009 in addition to a drilling an exploration well. On Chiguiro Oeste and Chiguiro Este, we are planning to drill an exploration well on each block in 2009 to test seismically defined exploration prospects.

Las Aguilas

Petrominerales tested the Conga-1 well on the Las Aguilas Block with fluctuating flow rates from the Caballos formation through the jet pump completion. In November 2008, we mobilized a heavy workover rig from Ecuador to the Conga-1 well on the Las Aguilas Block west of Orito, where testing operations recommenced. We are evaluating the Villeta intervals that have proven productive at Orito. On November 20, 2008 a general strike in the Putumayo forced us to suspend activities at this location until January 6, 2009. The planned 48 km² 3D seismic program over the Orito and Las Aguilas blocks during 2008 was also suspended. We have a two well commitment for the Las Aguilas Block which is to be completed in 2009.

Exploration Blocks – Peru

Block 126

The block's first phase commitments included the reinterpretation of 1,200 kilometres of 2D seismic, which has been completed and confirmed a large anomaly, the La Colpa structure, which was encountered by a well drilled on the block 20 years ago. Initially, three other structural leads have also been identified from the existing reprocessed 2D seismic. The next exploration phase will include the acquisition of 150 square kilometres of 3D seismic and 50 kilometres of 2D seismic, which is likely to commence later in 2009. An Environmental Impact Assessment has been submitted to the Peruvian government and a public consultation was completed in February 2009. Approval for the seismic program is expected in due course.

Petrominerales has been recognized as an operator in Peru by PeruPetro, however we have not received final approval on the 55% assignment of the Block 126 License Contract. The approval is expected to be received in due course from the Peruvian Ministry of Energy and Mines.

GENERAL

Employees

As at December 31, 2008, Petrobank has 128 employees in Canada and Petrominerales has 147 employees in Colombia.

Specialized Skill and Knowledge

The Company believes its success is dependent on the performance of its management and key employees, many of whom have specialized knowledge and skills relating to oil and gas operations. The Company believes that it has adequate personnel with the specialized skills required to successfully carry out its operations.

Environmental, Safety and Social Responsibility

Canadian Business Unit

Central to Petrobank's values is our commitment to the protection of people, the environment and the communities where we operate. This commitment from each of our employees drives our planning and actions. Worker safety and health are the shared responsibility of the Company and our employees. The Company ensures procedures, processes and training are in place and employees use these tools responsibly. As a team we manage safe operations.

Our Bakken field is operated by some of the most experienced individuals in the industry. Everyone is keenly aware of the importance of safe operations and our people have in-depth skills to manage worker and environmental protection. While we are extremely active implementing our development plans, every employee is mindful of our values to be good stewards of land, air, water, wildlife and people.

Our operations at Jumpbush provide us an opportunity to work closely with our employees, many of them First Nations members, to develop ongoing practices that are respectful of safe operating standards and sensitive to the culture of the lands where our operations are located.

At Princeton, we are developing our next program of investment. We are actively sharing knowledge with the community about the impacts of coalbed gas operations. The community now has the benefit of seeing how we conducted ourselves in our past programs. This increases the comfort levels towards future activities in an area previously unaccustomed to oil and gas activity. Our track record demonstrates our commitment to safe operations and respect for the environment and the community.

We recognize that our operations have an impact on the environment and we attempt to minimize this impact by following best practices. To ensure sustainability we must respect our natural environment and ensure our operations are carefully managed. Our employees live and work in the community, and are very aware of their commitment.

Our employees are our local representatives in the community. In every community in which we operate, it is our desire to be a welcomed neighbour. We encourage our people to be engaged with the community and create awareness of our operations. We believe in treating all communities and their members with respect.

This has been our practice in the Jumpbush field with the Siksika First Nation, likewise with the residents of Princeton and the many people living within and nearby our Bakken operations. We want to hear from community members and our website hosts this opportunity, along with toll free numbers, to promote open dialogue about our operations in their local areas.

Heavy Oil Business Unit

In 2007, Petrobank developed a Vision and Values statement that sets out our corporate responsibility commitments on environmental sustainability, health, safety and public engagement in those areas where we operate, all within the context of business integrity.

The Heavy Oil Business Unit uses best environmental practices in the planning, design, and implementation of exploration programs and heavy oil production. The objective is to minimize the environmental footprint of our operations and at the same time pursue new technologies which will also contribute to this objective.

We are committed to providing a healthy and safe working environment for employees, contractors and the general public. This is supported by dedicated staff and contractors who provide on-site health and safety support as well as ongoing hazard assessments, annual audits and training programs. Emergency response planning is integrated into all projects. On December 31, 2008, the Whitesands THAI™ Project surpassed 1000 days without a Lost Time Accident and we are committed to achieving even greater future milestones.

The Heavy Oil Business Unit is proactive in its communications with the local communities in Alberta and Saskatchewan where we are actively exploring or developing projects. The goal is to establish a fair and transparent consultation processes with all stakeholders, provide information on local business and employment opportunities, identify areas of interest or concern and develop mutually beneficial working relationships. We began a successful public engagement program in the Wood Buffalo region in 2003 as part of the planning and regulatory approval work for the Whitesands Pilot. This program has been expanded to include the May River Project, to ensure that both our regulatory compliance “duty to consult” requirements are met as well as to maintain established working relationships with directly affected stakeholders in the region.

Latin American Business Unit

In 2008, due to intensified exploration and production activities in several blocks, Petrominerales expanded its Occupational Health, Industrial Safety, Environmental Protection, Social Responsibility and Communities relations capacity by developing a Corporate Responsibility Management Program including additional responsibilities in government relations. Several achievements were realized in 2008 described below.

Health & Safety

In 2008, Petrominerales recorded a zero percent lost-time incidents record among its employees and at its facilities. Due to the increase in activities in seismic, drilling, workover, facilities construction and oil production, there was a slight increase in accidents reported by the contractors in the first semester. In response, we established periodic meetings with contractors, developed guides and industrial security procedures, among other activities.

In response to increased oil production, storage and transportation activities at Corcel, we also increased our capacity for responding to oil spills by developing Emergency Contingency Plans for each transportation route.

Environment

The Company completed its sixth year of field operations in Colombia with 100 percent environmental compliance in executing our exploration and production and IPC contract projects and activities. Our main environmental strategies include the preparation of comprehensive environmental impact assessments and assembling project-specific environmental management plans. Petrominerales encourages local community engagement in environmental planning in order to create a positive relationship between the oil business and local means of production.

By submitting its environmental impact assessments and environmental management plans according to the requirements of environmental authorities, Petrominerales again achieved an excellent standard in environmental licenses and permit awarding, and suffered no delays in project start-up and programming, thereby maintaining a high degree of compliance in its contractual commitments. The Company demonstrated excellent capabilities for environmental emergency response and control.

In 2008, Petrominerales focused on reducing the approval times for environmental approvals. Special attention was invested in preparing and presenting quality environmental studies (both environmental impact assessments and environmental management plans) to the Ministry of Environment, Housing and Territorial Development, and in working with the environmental authorities throughout the evaluation process.

Community Relations

Aside from Petrominerales' achievements in environmental planning and compliance, the Company has developed a series of policies and practices that compliment our basic responsibilities as a development tool for our surrounding communities. Our Corporate Social Responsibility strategy is based on three main principles:

- Creating local employment opportunities, which has been well received by communities and has contributed to maintaining a positive relationship in and around the Company's operations;
- Providing education and training programs to strengthen community and local authority relationships, identify new markets for local goods and services, and reduce dependence on industry support, and
- Engaging communities in studies and processes related to environmental management by combining the Company's expertise with local knowledge.

INDUSTRY CONDITIONS

Industry Conditions in Canada

The oil and natural gas industry is subject to extensive controls and regulations to govern its operation, which include exploration, development, production, marketing, transportation, and refining. These controls and regulations are imposed by legislation enacted by various levels of government. In addition, pricing and taxation of oil and natural gas is governed by agreements among the governments of Canada, British Columbia, Alberta, Saskatchewan, and Manitoba. It is not expected that any of these controls or regulations will affect the operations of Petrobank in a manner materially different than they would affect other oil and gas companies. All current legislation is a matter of public record and Petrobank is unable to predict what additional legislation or amendments may be enacted.

Land Tenure

Crude oil and natural gas located in Alberta, British Columbia, Saskatchewan and Manitoba are owned predominantly by the respective provincial governments, generally termed the “Crown”. Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is freehold (privately owned) and rights to explore for and produce oil and natural gas are granted by the mineral owners on negotiated terms and conditions. For information relating to land tenure with respect to the Company’s Heavy Oil Business Unit, see “*Heavy Oil Business Unit Overview – Whitesands Project*”.

Environmental Regulation

The Canadian oil and natural gas industry is governed by environmental regulation under federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission, and regulate the storage and transportation, of various substances produced or utilized in association with oil and gas industry operations. In addition, environmental laws require that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities in order to prevent pollution. Also, environmental laws may impose upon “responsible persons” remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past owner, tenant or other person in possession of the site. A breach of environmental laws may result in the imposition of fines and penalties, in addition to the costs of abandonment and reclamation.

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 nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases. In April 2007, the Federal Government proposed a new climate change plan that calls for greenhouse gas emissions to be reduced by 20 percent below current levels by 2020. This bill has not been passed yet. Facilities have a number of strategies to achieve these targets, including emission tradings, in-house reductions, or invest in a technology fund to research and develop greenhouse gas reduction technologies. In Alberta, new climate change regulations became effective July 1, 2007. These regulations require Alberta facilities that emit more than 100k tonnes of greenhouse gases a year to reduce emissions intensity by 12 percent over the average emission levels of 2003, 2004 and 2005. Companies can make their reductions through improvements to their operations; by purchasing Alberta-based credits or by contributing to the Climate Change and Emissions Management Fund.

Petrobank believes it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. The Company’s practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. Petrobank is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. The Company believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Company anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given however that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect the Company’s financial condition, capital expenditures, results of operations, competitive position or prospects.

Pricing and Marketing – Crude Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of crude oil. The price depends in part on the oil type, the quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of crude oil other than heavy crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the National Energy Board (“NEB”). Any crude 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 license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

In Canada, natural gas is sold throughout the country at various market hubs, which are connected to pipelines within Canada and the United States. The transaction price is determined by negotiation between natural gas producers, marketers and purchasers, and includes the utilization of electronic trading platforms, various publications and reference indices. Prices depend on many variables including but not limited to supply and demand fundamentals, the price of NYMEX natural gas contracts, distance to alternate markets, pipeline costs, natural gas storage levels, competing fuels, contract terms, weather, and foreign exchange. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters can negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. As in the case with oil, natural gas exported from Canada for a term of two years or less or for a term of between two and 20 years (in quantities of not more than 30,000 10³m³ per day) may be made pursuant to an NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of British Columbia, Alberta, Saskatchewan and Manitoba regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement (“NAFTA”) among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA, as it applies to trade between Canada and the United States, carries forward most of the material energy terms that are contained in the Canada-US Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade 1994, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, so long as any export restrictions do not:

- reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36 month period or another representative period agreed upon by the parties);
- impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports), or
- disrupt normal channels of supply to the United States.

Under NAFTA, each of Canada, the United States and Mexico are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Royalties and Incentives

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, NGL and sulphur production.

Royalties - Non-Crown lands

Royalties payable on production from lands, other than Crown lands, are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below.

Government Incentive Programs

From time to time, the federal and certain of the provincial governments have established incentive programs, which have included royalty rate reduction and tax credits (including the Canada Revenue Agency's Scientific Research and Experimental Development Program, Alberta Energy's Innovative Energy Technologies Program, Industry Canada's Technology Partnerships Canada Program, the Saskatchewan Petroleum Research Incentive, amongst others) to encourage oil and natural gas exploration or enhanced recovery projects.

Provincial Royalties - General

Royalty rates payable on production vary from province to province. 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.

Saskatchewan

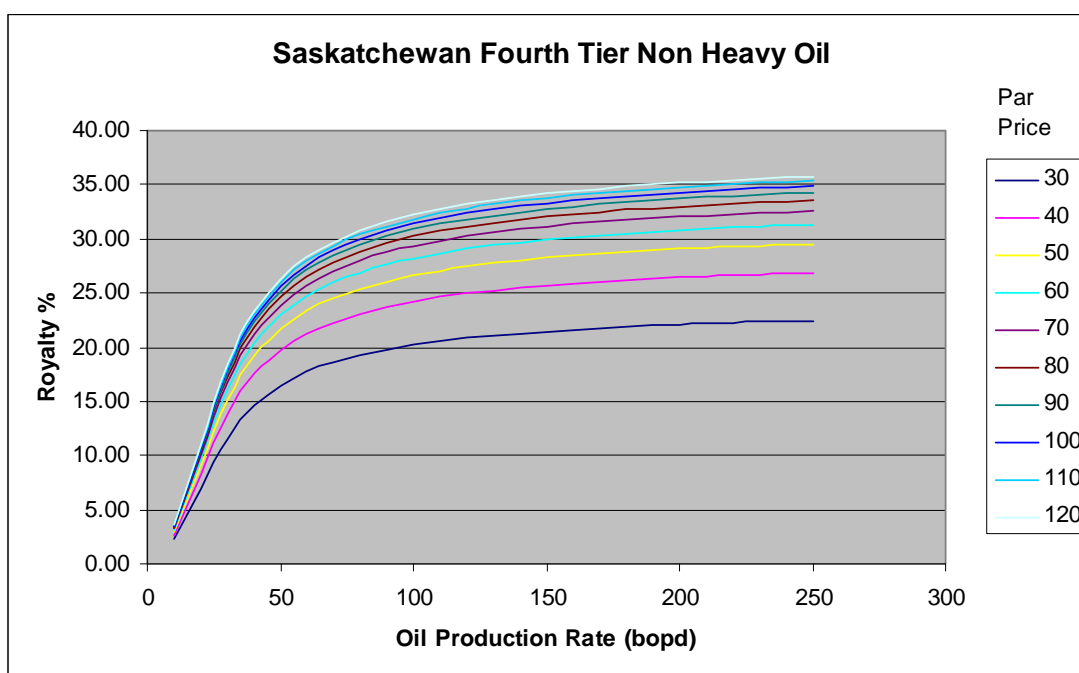
In Saskatchewan, crude oil Crown royalties and freehold production tax depend on well productivity, the current market price of oil, the classification and vintage of the oil and the quantity of oil produced in a month. Crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil", and the vintage classifications ("fourth tier oil", "third tier oil", "new oil" or "old oil") are applicable to each of these three crude oil types. Generally, the vintage of oil is based on the determination of whether the well was on production before January 1, 1974 ("old oil"), drilled between February 9, 1998 and October 1, 2002 ("new oil"), between January 1, 1974 (April 1, 1991 if horizontal) and January 1, 1994 (October 1, 2002 if horizontal) ("third tier oil"), or after October 1, 2002 ("fourth tier oil"). Newly drilled oil wells in Saskatchewan qualify for "volume based" incentives ranging from 0 to 16,000 m³, depending on the type of well (deep or non-deep, exploratory or development, and horizontal or vertical). Qualifying incentive volumes are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%.

Saskatchewan Crown royalties and freehold production tax on natural gas are price sensitive, depending also on the vintage of the natural gas, the quantity produced in a month, and whether the gas is associated (gas produced from oil wells) or non-associated. The vintage classifications of gas production are "fourth

tier gas”, “third tier gas”, “new gas” and “old gas”. Generally, the vintage of gas is based on the determination of whether the gas is produced from a well on production before October 1, 1976 (“old gas”), drilled between October 1, 1976 and February 9, 1998 (“new gas”), between February 9, 1998 and October 1, 2002 (third tier gas), or after October 1, 2002 (“fourth tier gas”). Newly drilled qualifying exploratory gas wells in Saskatchewan qualify for a 25,000,000 m³ “volume based” incentive. The qualifying incentive volume is subject to a maximum Crown royalty rate of 2.5% and a freehold production tax rate of 0%.

The majority of Petrobank’s production in Saskatchewan is “non-heavy oil other than southwest designated oil” with a vintage classification of “fourth tier oil”. Saskatchewan royalty payable on this production is 2.5% until 6,000 m³ (37,740 barrels) of oil have been produced.

Production in excess of this threshold is subject to a royalty rate based on well productivity and oil prices as demonstrated in the chart below.



British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil pool discovery (whether the oil was produced from a pool discovered before or after October 31, 1975), whether the oil is considered incremental or produced from a well shut-in for at least 36 months immediately preceding January 1, 1998 and which resumed production on or after such date, the quantity of oil produced in a month and the value of the oil. Oil produced from pools discovered after June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production. Subject to minimum royalties described in the following sentence, the royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other gas may not be less than 15%.

British Columbia Crown natural gas basic royalty, for the example of Base 9 gas typical of new drilling prospects, ranges from 9% to 27%, based on gas price. Low productivity wells, marginal wells and ultra marginal wells will have their royalties reduced and will approach 0% as the production rate approaches zero. During 2008, the Deep Well Program was extended, which provides royalty credits for wells with vertical depths greater than 2,500 m, or for horizontal wells with completion point vertical depth greater than 2,300 m. Royalty credit ranges from zero at 2,500 m to \$2.7 million at a depth of 5,500 m for wells located in the East map area of Northeast British Columbia, where Petrobank owns significant mineral rights.

Petrobank has an extensive inventory of drilling locations in the Monias areas. The royalty rate that is expected to apply to production from these areas is approximately 24%.

Alberta

In Alberta, the New Royalty Framework (“NRF”) became effective January 1, 2009. The NRF set variable royalties for bitumen, oil, gas and natural gas liquids. The NRF royalty rates vary with product price and production rate. For oil produced from Crown lands, the royalty reserved to the Alberta Crown on oil production ranges from 0% to 50% and is capped at 50% once the price of oil reaches \$120 per barrel. Under the New Oil Exploration Program announced in 2008, oil exploration wells that are drilled deeper than 2,000 m before 2014 are eligible for royalty relief up to \$1 million.

The NRF fixed royalties for natural gas liquids at 40% for pentanes and 30% for butanes and propane. For natural gas wells under the NRF, royalties range from 5% to 50% and is capped at 50% once the price of natural gas reaches \$16.59 per gigajoule. The royalty rate is reduced for wells with measured depth greater than 2,000 m and for wells with acid gas content greater than 3%. A Natural Gas Deep Drilling Program was announced in 2008 to provide royalty credits relief for wells drilled deeper than 2,500 m vertical depth, with increasing credits at greater depth subject to a cap of \$8 million. The credit is capped at \$10 million for deep gas wells that are considered exploratory. The Transitional Program, if passed, calculates royalties between 5% to 35% and provides a lower royalty rate than the NRF rate, when natural gas prices or gas well production rates are relatively high.

In November 2008, the Alberta Government announced an optional five-year transitional royalty program (“Transitional Program”). The Transitional Program applies to conventional oil and natural gas wells drilled to measured depths between 1,000 and 3,500 m between November 19, 2008 and January 1, 2014. For each well, the producer can make a one time election to produce the well under the Transitional Program instead of the NRF. As of January 1, 2014 all production subject to the Transitional Program will revert to the NRF royalty rates. The Deep Oil Exploration program is not available to wells which are producing under the Transitional Program. For oil produced under the Transitional Program, the royalty reserved to the Alberta Crown varies between 0% to 50% but a lower royalty rate, than the NRF rate, is calculated when oil prices or oil production rates are relatively high.

In March 2009, the Alberta Government introduced the Drilling Royalty Credit Program and the New Well Royalty Reduction Program as an incentive to increase drilling, completion and gathering work on conventional oil and gas wells. The Drilling Royalty Credit is earned at a rate of \$200/m of well depth drilled between April 1, 2009 and March 31, 2010. The credits for a company with Petrobank’s production level can be claimed up to 50% per year in years 2009 and 2010, as long as use of the credit does not reduce the company average Alberta Crown royalty rate to less than 5%. The New Well Royalty Reduction Program applies to all new wells that begin production between April 1, 2009 and March 31, 2009. The program provides for a 5% maximum royalty for the first 12 months of production as long as cumulative produced volume for the well is less than 50,000 barrels of oil or 500 mmcf of natural gas.

At Petrobank's Jumpbush property, within the Siksika Nation, royalties are payable to Indian Oil and Gas Canada, a branch of the Canadian Federal Government. The royalty on oil is paid on a well by well basis according to a sliding scale creating a royalty of 20% of the first 4.99 m³/day plus 35% of the next 10 m³/day plus 50% of the next 10 m³/day plus 60% of all production over 24.99 m³/day. Clean oil trucking costs are allowable deductions. Royalties on natural gas also are paid on sales volumes on a well by well basis according to a sliding scale providing for 25% of the first 24.99 10³m³/day plus 35% of the next 15 10³m³/day plus 50% of volumes over 39 10³m³/day. Gathering, processing and compression costs are allowable deductions provided that deductions do not exceed 50% of the gross proceeds of production. All wells at Jumpbush are currently producing >24.99 10³m³/day and accordingly pay royalties at the lowest rate.

Alberta - Heavy Oil

Currently, in respect of oil sands projects having regulatory approval, a royalty of one percent of gross bitumen revenue is payable prior to the payout of specified allowed costs, including certain exploration and development costs, operating costs and a return allowance. Once such allowed costs have been recovered, a royalty of the greater of: (a) one percent of gross bitumen revenue; and (b) 25 percent of net bitumen revenue (calculated as being gross bitumen revenue less operating costs and additional capital expenditures incurred since payout ("net royalty")) is levied.

Under the new regime, the Government of Alberta will increase its royalty share from oil sands production by introducing price-sensitive formulas which will be applied both before and after specified allowed costs have been recovered. The gross royalty will start at one percent of gross bitumen revenue and will increase for every dollar that world oil price, as reflected by the WTI crude oil price, is above \$55 per barrel, to a maximum of nine percent when the WTI crude oil price is \$120 per barrel or higher.

The net royalty on oil sands will start at 25% of net bitumen revenue and will increase for every dollar the WTI crude oil price is above \$55 per barrel to 40% when the WTI crude oil price is \$120 per barrel or higher. Prior to the payout of specified allowed costs, including certain exploration and development costs, operating costs and a return allowance, the gross royalty is payable. Once such allowed costs have been recovered, a royalty of the greater of: (a) the gross royalty and (b) the net royalty is payable.

Industry Conditions in Colombia

Historically, all oil production in Colombia was undertaken by Ecopetrol in contracts of association with foreign companies that allowed Ecopetrol to back into exploration discoveries for up to 50 percent working interest. Ecopetrol is the Colombian national company responsible for exploration, extraction, production, transportation, and crude marketing for export. Colombia was considered to be at risk of becoming a net oil importer and as a result, the regulatory regime in Colombia underwent a significant change effective January 1, 2004 with the formation of the ANH, which has the responsibility of regulating the Colombian oil industry. As this function was previously performed by Ecopetrol, Ecopetrol now competes directly with foreign companies. This change, along with increased commodity prices, has resulted in a significant increase in Colombian exploration activity.

There are seven commercial oil production basins in Colombia: the Upper, Middle, and Lower Magdalena Valley; Llanos; Putumayo; Catatumbo, and the Guajira basins. Oil extracted from fields in these basins is transported through Colombia's five major oil pipelines, four of which connect production fields to the Caribbean port town of Coveñas. These are the central Ocesa pipeline, which transports oil from the Llanos Basin and Cusiana-Cupiagua fields, the 490-mile Caño Limon pipeline, the Alto Magdalena and Colombia Oil pipelines, and the Transandino or Trans-Andean (OTA), transports crude from the Orito field in the Putumayo Basin to Colombia's Pacific port of Tumaco.

ANH

The regulatory regime in Colombia underwent a significant change, effective January 1, 2004, with the formation of the ANH, which has the responsibility of regulating the Colombian oil industry. In conjunction, the ANH developed a new exploration risk contract that took effect near the end of the first quarter of 2005. This contract has changed the way the industry views Colombia and has significantly increased the amount of new exploration in the country. In place of the earlier association contracts in which the government (Ecopetrol) had an immediate back-in to production, the ANH agreement provides full risk/reward benefits for the contractor. Under the terms of the ANH contract the successful operator retains the rights to all reserves, production and income from any new exploration block, subject to existing royalty and income tax regulations with a windfall surcharge provision for larger fields.

Previously the ANH dealt with exploration acreage proposals on a “first-come, first-served” basis, but has since adopted a system of competitive bidding rounds, or rounds whereby the ANH invites a selected group of companies to submit proposals. Once the ANH is satisfied that the successful oil company has the proper technical and financial resources to fulfill its obligations under the proposed ANH contract, a definitive work program is negotiated. This work program typically includes technical studies, reprocessing or shooting new seismic, and/or drilling wells. The ANH contract term consists of three phases: (i) the initial exploration phase which lasts six years and can be extended for up to an additional four years; (ii) upon a declared discovery, and at the contractor’s request, the evaluation phase commences and lasts one to two years with up to a two year extension possible, during which the contractor must declare commerciality or relinquish the block; and (iii) the production phase with a basic 24 year term, extendable under certain circumstances. The duration of the exploration period is six years; however, the contractor may request an extension for up to four additional years provided that it presents an additional exploration program and relinquishes 50 percent of the area. Depending on the period requested this period is also divided into phases as the contractor proposes. All discoveries must be reported to the ANH, while the Colombian Ministry of Mines and Energy defines the extent of the discovery.

If a discovery is made, the contractor has the option to request an appraisal period for up to two years, depending on the size and scope of the evaluation plan proposed. If, in the opinion of the ANH, there is sufficient reason, this period may also be extended. If the evaluation plan relates to a gas or heavy oil field, two additional years may be granted because of the complex planning and marketing required. At the end of this phase, the contractor must declare commerciality or return the block.

Once the evaluation phase is complete and the operator declares commerciality, the exploitation phase begins. The duration of the exploitation period of each declared field is 24 years. The contractor may obtain an extension of the exploitation period beyond the 24 years, if the contractor complies with three basic requirements: continuous production; an active enhanced oil recovery plan or infill project, and a payment of five percent for gas to 10 percent for oil of the remaining reserves value.

Relinquishment of part or all the license area depends on the phase in which operations are. Under normal circumstances the contractor must relinquish 50 percent of the area at the end of the six-year exploration period if the contractor continues to explore, and there is an evaluation program or a discovery. If not, the operator must relinquish 100 percent. Another 25 percent must be relinquished after the two-year evaluation phase expires. The operator and the ANH may also agree on the relinquishment of certain parts of a license area during the initial six-year exploration period as part of the contract and on a block by block basis, depending on the scope of the exploration work program and the size of the area. The contractor also has the option to relinquish all or part of the area after each exploration phase.

Royalties

Historically, for new field production commencing prior to July 25, 2002, a flat 20 percent royalty applied. For new field production commencing after July 25, 2002, royalties are calculated on a per field basis using a sliding scale that ranges from eight percent (for production up to 5,000 bbl/d) up to a maximum of 25 percent (for production above 600,000 bbl/d), illustrated as follows:

<u>Field Production (bbl/d)</u>	<u>Royalty Rate*</u>
0 – 5,000	8%
5,001 – 125,000	8% - 20%
125,001 – 400,000	20%
400,001 – 600,000 plus	20% - 25%

* For new discoveries of heavy oil, classified as those with an API equal to or less than 15°, the royalties will be 75% of the royalty rates for light and medium oils presented above.

All of Petrominerales' Colombian contracts are subject to this sliding scale royalty.

Windfall Profits Tax

For contracts signed under the new oil and gas regulatory regime, 2004 onwards, a windfall profit tax applies once a field has cumulatively produced more than five million barrels of oil, determined before the deduction of royalties. The windfall surcharge is paid at 30 percent of the price received in excess of certain threshold prices, based on the oil quality produced, as follows:

<u>Quality</u>	<u>2009 Threshold Prices</u>
Less than 10° API	Nil
10° to 15° API	US\$46.50/bbl
15° to 22° API	US\$32.56/bbl
22° to 29° API	US\$31.39/bbl
Greater than 29° API	US\$30.22/bbl

Crude oil production with a quality above 29 API and a realized oil price of US\$50/bbl results in windfall surcharge which is equivalent to an incremental 11.9% royalty, bringing the total government take to 19.9% for a field with production less than 5,000 bbl/d. Threshold prices are adjusted annually for inflation.

The windfall profits tax does not apply to Petrominerales' Incremental Production Contracts.

Overriding Royalties in Petrominerales E&P Contracts

The Corcel Block was subject to a three percent GORR before payout granted to the original owner, which converted to an eight percent net profits interest in 2008, while the Joropo Block is subject to a ten percent GORR before payout granted to the original owner of the block, which converts to a twenty-two percent net profits interest after payout. These are the only third-party interests that affect Petrominerales' exploration and production blocks.

Incremental Production Contracts

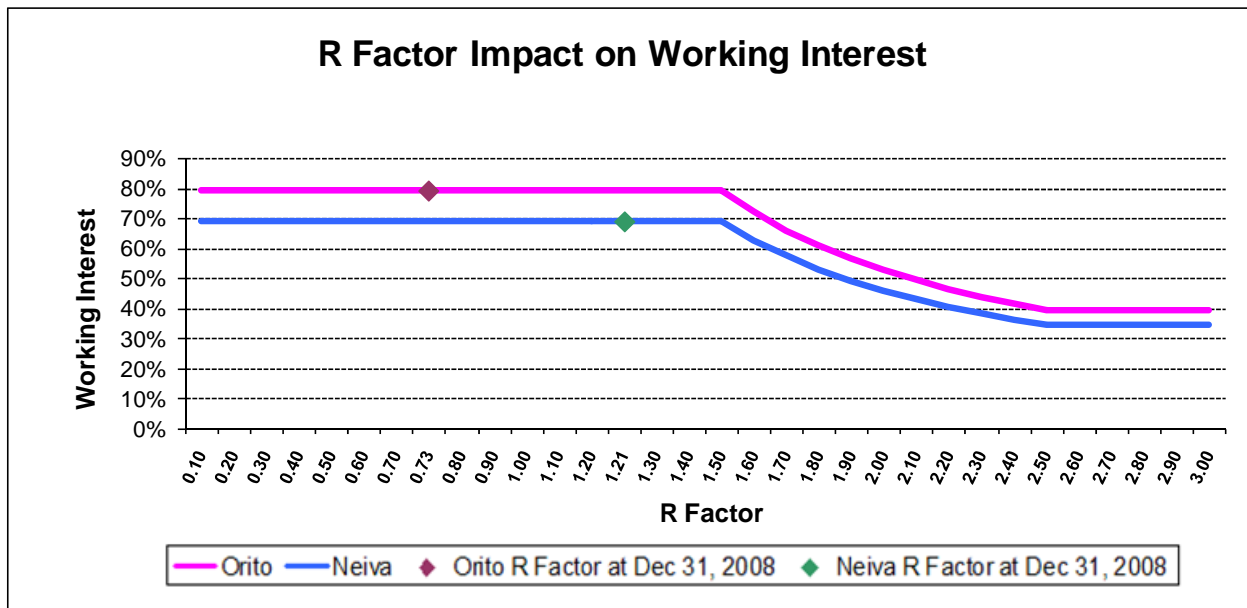
Petrominerales is the owner of interests in, and is engaged in the exploration for and development and production of oil from, two IPCs (Orito and Neiva) granted by Ecopetrol. Each block is governed by a separate contract with Ecopetrol. Each IPC covers a specific period, expiring in June 2023, and required certain expenditures in the early years of the contract in order to advance to subsequent development

phases. Petrominerales' earlier activities focused on fulfilling initial work commitments on these IPC's, which gives Petrominerales the right to carry out development activities on the blocks and share in incremental production generated above a pre-defined declining baseline. Petrominerales' participation levels at Orito and Neiva are 79 percent and 69 percent, respectively. These participation levels decline on a contract by contract basis once the ratio of cumulative total revenues to total costs "R factor" exceeds 1.5 times. At R factors above 2.5 times the participation levels at Orito and Neiva are fixed at 39.5 percent and 34.5 percent, as indicated in the following table:

R Factor	Orito	Neiva
1.5 to 2.5	79%/(R-0.5)	69%/(R-0.5)
2.5 or more	39.5%	34.5%

The cumulative revenues, costs and R Factors as at December 31, 2008 for each of Petrominerales' IPC's were as follows:

	Orito (USMMS\$)	Neiva (USMMS\$)
Cumulative revenue	218.2	36.9
Cumulative costs	297.3	30.4
R Factor	0.73	1.21



Cumulative revenues include Petrominerales' interest oil sales made from the block before the deduction of royalties. Cumulative costs include transportation expenses, operating expenses and capital costs.

Peru

Peru, located on the west Central Coast of South America, is a constitutional republic characterized by a stable market orientated government that possesses a strong commitment to hydrocarbon exploration and production. Peru offers an attractive royalty structure that guarantees, through legislation, taxation levels throughout the term on an awarded block. Peruvian Law N° 26221, enacted in 1993, comprises the entire

hydrocarbon legal framework and eliminated the previous state monopoly on hydrocarbon importation transportation, refining and distribution.

PeruPetro S.A. is the Peruvian private law state company responsible for promoting the investment of hydrocarbon exploration and exploitation activities in Peru. The country is a net oil importer and as a result, the regulatory regime in Peru is very competitive compared to other foreign jurisdictions. This competitive regulatory regime, combined with significant blocks of unexplored acreage and high commodity prices in 2007 and 2008 has resulted in a significant increase in Peruvian exploration activity.

Peru has a long history of petroleum exploration. The first wells were drilled in Peru in 1875. These wells were located in the Talara Basin; an onshore basin that extends offshore, located along the North West coast of Peru. The best known basin in Peru is the Marañon Basin, the southern extension of the Oriente Basin of Ecuador and the Putumayo Basin of Colombia, where Petrominerales' Orito Field is located. The Ucayali Basin is located in east Central Peru. Today, the 140,000 km² basin is defined by tectonic elements to the North, the Contaya Arch and to the South by the Fitzcarrald Arch. The basin is 650 km in length and approximately 250 km in width.

The western part of the basin is defined by the sub-Andean thrust and fold belt while the eastern edge of the basin is constrained by the Brazilian Shield. The basins contain in excess of 5,000 metres of sedimentation ranging in age from the Paleozoic to the Tertiary and Quaternary. The Ucayali Basin has experienced several episodes of extension and rifting that has affected the sedimentary history with the result that the Ucayali Basin has similar tectonic history to the Western Canadian Sedimentary Basin. Prospectivity is found from a variety of play types, multiple reservoirs and the presence of several source rocks within a sedimentary column of up to 16,000 feet.

General activity by third parties in Peru includes; fifty wells drilled by in the Ucayali Basin, and 13,400 km of seismic data acquired. Three oilfields have been discovered, the Agua Caliente (1938), Maquia (1958) and the Pacay (1958). In 1984, the first of the five gas/condensate fields which form part of the Camisea gas field were discovered. These pools are the San Martin (1984), the Cashiriari (1996), the Pagorene (1998), the Mipaya (1987) and the Aguaytia (1961).

Peru - Hydrocarbon Law & License Contracts

Law N° 26221, enacted in 1993, comprises the entire hydrocarbon legal framework and eliminated the previous State monopoly on hydrocarbon importation, transportation, refining and distribution.

The License Contract term consists of two phases: (i) the initial exploration phase which lasts seven years and can be extended for up to an additional three years; and (ii) upon a declared discovery, and at the contractor's request, the exploitation phase commences with a 30 year term (40 years for natural gas), extendable under certain circumstances. The duration of the exploration period is seven years; however, the contractor may request an extension for up to three additional years provided that it has fully complied with the minimum work programs for the four exploration phases. The exploration phase of a License Contract is divided into four phases, each phase has minimum work program that is defined in Exploration Work Units (EWU). Each EWU is assigned a value of \$5,000, and exploration activities are assigned EWU values, as follows:

2D seismic	1 EWU per km
3D Seismic	3 EWU per km ²
2D reprocessing	0.02 EWU per km
Well 0 – 1000 metres	0.01 EWU per metre
Well 1001 – 2000 metres	0.13 EWU per metre

Well 2001 – 3000 metres	0.18 EWU per metre
Well 3001 – 4000 metres	0.22 EWU per metre
Well > 4001 metres	0.25 EWU per metre

The benefit of this system is that it permits flexibility for the exploration company to change program without the necessity of regulatory approval.

If a discovery is made but it is non-commercial only for reasons of transportation, the contractor may request a retention period of up to five years (ten years for natural gas) in order to make transportation feasible. At the end of the exploration phase, the contractor must declare commerciality or return the block.

Once the exploration phase is complete and the operator declares commerciality, the exploitation phase begins. The duration of the exploitation period of each declared field is 30 years (40 years for natural gas). All discoveries are reported to PeruPetro.

Relinquishment of part or all of the license area depends on the phase in which operations are. Under normal circumstances the contractor must relinquish 60 percent of the area at the end of the seven-year exploration period if the contractor continues to explore, and there is an evaluation program or a discovery. If not, the operator must relinquish 100 percent. The operator and the ANH may also agree on the relinquishment of certain parts of a license area during the initial seven-year exploration period as part of the contract and on a block by block basis, depending on the scope of the exploration work program and the size of the area. The contractor also has the option to relinquish all or part of the area after each exploration phase.

Peru - Royalties and Taxes

The hydrocarbon law establishes that royalties may be determined in one of two ways, at the election of the operator. One method is based on production levels; the second method is based on the economic results methodology. Once the operator declares a commercial discovery, it must elect one of the royalty schemes to be applicable to the block's production. Once the royalty scheme is selected for a License Contract, it cannot be changed. The royalty structure has been in place for five years.

When the operator elects to have royalties based on production levels, the following sliding scale illustrates the applicable royalty rate:

<u>Field Production (bbl/d)</u>	<u>Royalty Rate</u>
0 – 5,000	5%
5,001 – 100,000	5% - 20%
> 100,000	20%

When the operator elects to have royalties based on the economic results methodology, the royalty payable consists of a five percent fixed royalty plus a variable profits interest calculated using income and expenditures, that has a maximum value of 20%.

The statutory tax rate applicable to corporate income is 30%, and tax losses can be carried forward for four years. The Peruvian government, through the Ministry of Economy and Finance, guarantees the benefit of tax stability for the operations carried out under a License Contract.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

The reserves data set forth herein is based upon evaluations completed by McDaniel, Sproule, and D&M (collectively, the “Evaluators”). Each of the McDaniel Report, the Sproule Report and the D&M Report (collectively referred to herein as the “Reports”) is dated effective December 31, 2008. The reserves data contained herein summarizes the oil, liquids, natural gas and bitumen reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data complies with the requirements of NI 51-101. Certain additional information not required by NI 51-101 has been included herein to provide readers with further information regarding our properties. Petrobank engaged the Evaluators to provide evaluations of proved, probable, and possible reserves and contingent resources.

All of the Company’s reserves are in Colombia, through its interest in Petrominerales, and Canada (specifically, in the provinces of Saskatchewan, Alberta, British Columbia, and Manitoba).

In preparing the Reports, basic information was provided to the Evaluators by Petrobank, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluations and upon which the Reports are based, was obtained from public records, other operators and from the Evaluators non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the Reports, from all sources, was accepted by the Evaluators as represented.

The tables and information contained herein, show the estimated share of Petrobank’s crude oil, natural gas and NGL reserves in its Canadian properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast prices and costs as indicated. Colombian estimated future net revenue based on the D&M Report is presented in US dollars and in presenting Company totals has been converted into Canadian dollars using the forecast price case US\$ exchange rate of US\$1.00 = \$1.2246.

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned and future site restoration and reclamation costs for wells in Canada to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company’s properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.

The reserves data contained herein is based on the Evaluators respective price forecasts, in each case as of December 31, 2008.

Undeveloped Reserves

Petrobank attributes proved, probable, and possible undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of

reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields.

Subject to the success of operations, within the next two years, the Company has the following plans regarding the development of proved, probable and possible undeveloped reserves:

1. The Company's proved undeveloped reserves will be developed through further drilling and completion of wells within these areas. In 2009, the Company's planned drilling program consists of six locations at Corcel, two locations at Orito and 16 at Neiva along with workovers in all areas and fracture stimulations in both Orito and Neiva. The 2010 drilling and completions schedule will focus on these three areas and on any other opportunities arising from the Company's exploration programs. The D&M Report includes the following:
 - **Corcel:** 1 Proven Undeveloped (A2 sidetrack), 2 Probable (C2 and A3 sidetrack) and 4 Possible locations (E1, E2, B1, G1)
 - **Orito:** 20 Proven Undeveloped, 8 Probable and 15 Possible locations
 - **Neiva:** 16 Proven Undeveloped, 12 Probable and 8 Possible locations

2. Proved undeveloped reserves in the Jumpbush gas field and in the Bakken oil pools were assigned on the basis of the regional nature of the producing formations. Performance expectations are based on offset well production. Bakken well locations typically were assigned where economic production has been demonstrated by wells in offsetting spacing units. The Sproule Report has assigned proved undeveloped reserves to 116.5 net light oil well locations in the Bakken properties in southeast Saskatchewan. For the southeast Saskatchewan proved undeveloped program, 81% of the capital is forecast to be spent in 2009 with the balance to be spent in 2010. The Sproule Report has assigned proved undeveloped reserves to 61.4 net shallow gas well locations at Jumpbush with 65% of the Jumpbush capital forecast to be spent in 2009 and the balance to be spent in 2010.

Probable undeveloped reserves at Jumpbush and in the Bakken properties generally assigned adjacent to proved well locations. The Bakken in southeast Saskatchewan produces light oil plus solution gas and associated liquids based on typical gas/oil ratios and typical condensate yields where the gas is gathered. The Sproule Report has assigned probable undeveloped reserves to 45 net locations in the Bakken properties in southeast Saskatchewan plus possible undeveloped reserves to 19.5 locations with 56% of the capital for the southeast Saskatchewan probable undeveloped reserves is forecast to be spent in 2009 and the balance to be spent in 2010. The Sproule Report has assigned probable undeveloped reserves to seven net locations at Jumpbush plus possible undeveloped reserves to 13 net locations. All of the capital for probable undeveloped reserves at Jumpbush was scheduled to be spent for 2009.

Drilling plans are affected by economic considerations including commodity prices and the companies drilling plan for 2009 is expected to range from 40 to 120 wells in southeast Saskatchewan depending on the commodity prices.

Undeveloped reserves, like all projects, are subject to competition for capital and consequently may be delayed or accelerated from time to time.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. The reserve data included herein represents 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, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. 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 expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to 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. 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 will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, the Company has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also 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.

In Canada, at Jumpbush, a portion of the Company's development plans are subject to a lengthy approval process that could result in delays in bringing new reserves on-stream. Delays could adversely impact net present values of assigned reserves.

In Colombia, Petrominerales' reserves at Orito and Neiva are subject to an 'R' factor calculation, under which Petrominerales' interest in reserves decreases as the ratio of cumulative revenues to cumulative costs increases. Accordingly, at higher prices Petrominerales' reserve values increase but reserve volumes decline, thereby increasing reserve uncertainty.

Summary of Heavy Oil Business Unit Contingent Resources

The Heavy Oil Business Unit's reserve and Contingent Resource estimates are currently based on SAGD technology as it is the presently recognized technology used to determine recoverable in-situ oil sands reserves.

The following tables summarize the McDaniel Report, as at December 31, 2008. The following tables present the Low Estimate Contingent Resources and High Estimate Contingent Resources, along with the Best Estimate Contingent Resources, for summary purposes only. Unless otherwise noted in this Annual Information Form, the Company has presented Contingent Resources on a Best Estimate basis. See "*Notes on Reserves Data - Contingent Resource Categories*".

For additional information relating to the Heavy Oil Business Unit's Contingent Resources, please see the disclosure under the heading "Heavy Oil Business Unit Overview", including the following sub-headings "Challenges of the Canadian Oil Sands", "Whitesands Project", "THAI™ Applicability in the Canadian Oil Sands" and "Intellectual Property".

**HEAVY OIL BUSINESS UNIT RESERVES / RESOURCES⁽¹⁾
AS OF DECEMBER 31, 2008**

Based on SAGD technology (mbl)

Probable Reserves (2P)	68,982
Probable plus Possible Reserves (3P)	77,670
Low Estimate Contingent Resources ⁽²⁾⁽³⁾	485,162
Best Estimate Contingent Resources ⁽²⁾⁽³⁾	599,215
High Estimate Contingent Resources	737,062
2P + Best Estimate Contingent Resources	668,197
3P + High Estimate Contingent Resources	814,732

Notes:

1. Gross reserves and/or resources include the working interest reserves/resources before deductions of royalties payable to others.
2. Contingent resources, as evaluated by McDaniel, are those quantities of bitumen estimated to be potentially recoverable using SAGD technology from known accumulations but are classified as a resource rather than a reserve primarily due to the absence of regulatory approvals, detailed design estimates and near term development plans and are in addition to 3P reserves.
3. A low estimate means higher certainty (P90), a best estimate (P50) means most likely and a high estimate means lower certainty (P10).

**HEAVY OIL BUSINESS UNIT'S BEFORE TAX NET PRESENT VALUES
AS OF DECEMBER 31, 2008**

Based on SAGD	\$MILLIONS ⁽¹⁾⁽²⁾⁽³⁾					
Net Present Value Discounted at:	0%	5%	8%	10%	15%	20%
Probable Reserves (2P)	1,239.5	601.3	392.8	294.3	134.0	44.4
Probable plus Possible Reserves (3P)	1,648.4	788.2	522.6	400.4	206.5	100.5
Low Estimate Contingent Resources	8,341.1	2,928.0	1,482.8	879.3	43.9	(308.0)
Best Estimate Contingent Resources	12,590.5	4,402.8	2,387.8	1,573.6	470.0	1.0
High Estimate Contingent Resources	18,341.3	5,806.3	3,102.6	2,070.1	732.9	182.0
2P + Best Estimate Contingent Resources	13,830.0	5,004.1	2,780.6	1,867.9	604.0	45.4
3P + High Estimate Contingent Resources	19,989.7	6,594.5	3,625.2	2,470.5	939.4	282.5

Notes:

1. Based on McDaniel forecast bitumen netback prices.
2. Interest expenses and corporate overhead, etc. were not included.
3. The net present values may not necessarily represent the fair market value of the reserves and/or resources.

Ownership of Petrominerales

As at December 31, 2008 the Company held an indirect 76.5% interest in Petrominerales. As at December 31, 2008, the D&M Report estimated Petrominerales' share of proved and probable reserves, representing 100% of the working interest of Petrominerales, which were consolidated in the Company's accounts. Minority shareholders indirectly owned 23.5% of these reserves at December 31, 2008.

The table below represents a summary of reserves indirectly owned by Petrominerales' minority shareholders and a summary of the net present value (before tax) of such reserves, all as at December 31, 2008, showing the Petrominerales' minority shareholder interest of 23.5%. All reserves stated herein are based on forecast prices and costs and are company interest reserves after Ecopetrol's (the Colombian national oil company) share, and before royalties.

**MINORITY SHAREHOLDERS' INTERESTS IN LATIN AMERICAN BUSINESS UNIT RESERVES AND NET PRESENT VALUE
AS OF DECEMBER 31, 2008**

Reserves – Company Interest	Light and Medium Oil ⁽¹⁾ (mdbl)	Net Present Value 10% Before Tax (US\$ millions)
Developed Producing	3,344	114.5
Total Proved	5,916	195.5
Total Proved + Probable	8,660	288.9
Total Proved + Probable + Possible	12,917	425.0

Note:

1. Includes natural gas liquids.

**SUMMARY OF OIL AND GAS RESERVES
FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2008**

RESERVES CATEGORY	RESERVES							
	LIGHT AND MEDIUM OIL		NATURAL GAS ⁽¹⁾		NATURAL GAS LIQUIDS		BITUMEN	
	Gross (mdbl)	Net (mdbl)	Gross (mmcf)	Net (mmcf)	Gross (mdbl)	Net (mdbl)	Gross (mdbl)	Net (mdbl)
Canadian And Heavy Oil Business Units (Canada) ⁽³⁾								
Proved								
Developed Producing	20,191	18,653	27,696	24,156	1,694	1,587	-	-
Developed Non-Producing	1	1	5,811	4,451	317	275	-	-
Undeveloped	9,757	8,859	14,403	11,449	520	479	-	-
Total Proved	29,948	27,513	47,910	40,056	2,532	2,340	-	-
Probable	14,581	13,613	20,127	16,752	1,136	1,039	68,982	56,248
Total Proved Plus Probable	44,529	41,126	68,037	56,808	3,668	3,379	68,982	56,248
Possible	20,987	19,203	24,618	20,735	1,560	1,470	8,688	5,875
Proved Plus Probable Plus Possible	65,517	60,328	92,654	77,543	5,227	4,849	77,670	62,123
Latin American Business Unit (Colombia) ⁽²⁾								
Proved								
Developed Producing	14,229	13,057	-	-	-	-	-	-
Undeveloped	10,385	9,551	-	-	560	515	-	-
Total Proved	24,614	22,608	-	-	560	515	-	-
Probable	11,469	10,514	-	-	206	191	-	-
Total Proved Plus Probable	36,083	33,122	-	-	766	706	-	-
Possible	17,577	16,073	-	-	539	495	-	-
Proved Plus Probable Plus Possible	53,660	49,195	-	-	1,305	1,201	-	-
Canada & Colombia ⁽²⁾								
Proved								
Developed Producing	34,420	31,710	27,696	24,156	1,694	1,587	-	-
Developed Non-Producing	1	1	5,811	4,451	317	275	-	-
Undeveloped	20,142	18,410	14,403	11,449	1,080	994	-	-
Total Proved	54,562	50,121	47,910	40,056	2,532	2,855	-	-
Probable	26,050	24,127	20,127	16,752	1,342	1,230	68,982	56,248
Total Proved Plus Probable	80,613	74,248	68,037	56,808	3,874	4,085	68,982	56,248
Possible	38,564	35,276	24,618	20,735	2,099	1,965	8,688	5,875
Proved Plus Probable Plus Possible	119,177	109,523	92,654	77,543	5,972	6,050	77,670	62,123

Notes:

⁽¹⁾ Includes associated, non-associated, and solution gas.

⁽²⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values".

* Table may not add due to rounding.

FORECAST PRICES AND COSTS
NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2008

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT					AFTER HOST COUNTRY INCOME TAXES DISCOUNTED AT					FUTURE NET VALUE ⁽¹⁾ 10%/year (\$/boe)
	(%/year)					(%/year)					
	0	5	10	15	20	0	5	10	15	20	
	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	
Canadian Business Unit (Canada)											
Proved											
Developed Producing	1,395,539	1,069,188	874,814	747,358	657,608	1,265,294	988,762	821,544	710,148	630,537	36.05
Developed Non-Producing	10,441	957	(4,342)	(7,594)	(9,733)	7,589	(537)	(5,185)	(8,101)	(10,054)	(4.27)
Undeveloped	434,352	286,214	197,919	140,631	101,003	300,652	188,898	122,263	79,135	49,446	17.60
Total Proved	1,840,331	1,356,359	1,068,391	880,395	748,878	1,573,535	1,177,123	938,622	781,182	669,929	29.25
Probable	1,168,151	649,338	421,509	301,367	228,985	846,817	466,618	299,672	211,584	158,520	24.16
Total Proved Plus Probable	3,008,482	2,005,697	1,489,900	1,181,762	977,863	2,420,352	1,643,741	1,238,294	992,767	828,449	27.60
Possible	2,049,916	885,039	511,121	345,104	253,961	1,483,629	639,165	367,397	246,607	180,305	21.18
Proved Plus Probable Plus Possible	5,058,398	2,890,736	2,001,021	1,526,866	1,231,824	3,903,981	2,282,906	1,605,691	1,239,374	1,008,754	25.62
Heavy Oil Business Unit (Canada)											
Proved											
Developed Producing	1,239,504	601,336	294,337	134,015	44,446	924,255	434,336	198,576	75,386	6,582	5.23
Total Proved Plus Probable	1,239,504	601,336	294,337	134,015	44,446	924,255	434,336	198,576	75,386	6,582	5.23
Possible	408,942	186,844	106,076	72,442	56,098	307,028	142,075	82,903	58,565	46,807	18.06
Proved Plus Probable Plus Possible	1,648,446	788,180	400,413	206,457	100,544	1,231,283	576,411	281,479	133,952	53,389	6.45
Canada Total											
Proved											
Developed Producing	1,395,539	1,069,188	874,814	747,358	657,608	1,265,294	988,762	821,544	710,148	630,537	36.05
Developed Non-Producing	10,441	957	(4,342)	(7,594)	(9,733)	7,589	(537)	(5,185)	(8,101)	(10,054)	(4.27)
Undeveloped	434,352	286,214	197,919	140,631	101,003	300,652	188,898	122,263	79,135	49,446	17.60
Total Proved	1,840,331	1,356,359	1,068,391	880,395	748,878	1,573,535	1,177,123	938,622	781,182	669,929	29.25
Probable	2,407,655	1,250,674	715,846	435,382	273,431	1,771,072	900,954	498,248	286,970	165,102	9.71
Total Proved Plus Probable	4,247,986	2,607,033	1,784,237	1,315,777	1,022,309	3,344,607	2,078,077	1,436,870	1,068,152	835,031	16.19
Possible	2,458,858	1,071,883	617,197	417,546	310,059	1,790,657	781,240	450,300	305,172	227,112	20.57
Proved Plus Probable Plus Possible	6,706,844	3,678,916	2,401,434	1,733,323	1,332,368	5,135,264	2,859,317	1,887,170	1,373,325	1,062,143	17.13
Latin American Business Unit (Colombia)⁽²⁾											
	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US\$/bb1)
Proved											
Developed Producing	606,882	540,866	487,162	454,073	405,421	529,064	469,631	421,163	390,794	347,419	37.31
Undeveloped	594,498	448,189	344,761	272,807	214,476	431,205	328,622	255,362	202,334	161,738	34.25
Total Proved	1,201,380	989,055	831,923	726,880	619,897	960,269	798,253	676,525	593,128	509,157	35.98
Probable	611,135	487,547	397,484	336,913	277,805	397,137	315,930	256,761	216,083	178,156	37.13
Total Proved Plus Probable	1,812,515	1,476,602	1,229,407	1,063,793	897,702	1,357,406	1,114,183	933,286	809,211	687,313	36.34
Possible	926,203	723,314	579,154	490,810	394,839	621,718	484,727	387,271	327,061	262,552	34.96
Proved Plus Probable Plus Possible	2,738,718	2,199,916	1,808,561	1,554,603	1,292,541	1,979,124	1,598,910	1,320,557	1,136,272	949,865	35.89
Canada & Colombia⁽²⁾⁽³⁾											
	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(\$/boe)
Proved											
Developed Producing	2,138,727	1,731,533	1,471,393	1,303,416	1,154,087	1,913,186	1,563,872	1,337,300	1,188,714	1,055,986	39.42
Developed Non-Producing	10,441	957	(4,342)	(7,594)	(9,733)	7,589	(537)	(5,185)	(8,101)	(10,054)	(4.27)
Undeveloped	1,162,374	835,066	620,113	474,710	363,650	828,706	591,329	434,979	326,913	247,510	29.10
Total Proved	3,311,542	2,567,556	2,087,164	1,770,532	1,508,004	2,749,481	2,154,664	1,767,094	1,507,526	1,293,442	34.99
Probable	3,156,051	1,847,724	1,202,605	847,966	613,631	2,257,406	1,287,842	812,678	551,585	383,272	14.25
Total Proved Plus Probable	6,467,593	4,415,280	3,289,769	2,618,498	2,121,635	5,006,887	3,442,506	2,579,772	2,059,111	1,676,714	22.84
Possible	3,593,086	1,957,653	1,326,429	1,018,592	793,579	2,552,013	1,374,837	924,552	705,691	548,633	28.48
Proved Plus Probable Plus Possible	10,060,679	6,372,933	4,616,198	3,637,090	2,915,214	7,558,900	4,817,343	3,504,324	2,764,802	2,225,347	24.22

Notes:

⁽¹⁾ Unit values are based on net reserve volumes and future net revenue before income tax⁽²⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held a 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see *Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales* and *Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values*.⁽³⁾ U.S. dollars are converted into Canadian dollars using an exchange rate of \$1.2246.

* Table may not add due to rounding.

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2008**

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)
Canadian Business Unit (Canada)								
Total Proved	3,154,371	342,248	655,330	289,109	27,353	1,840,331	266,796	1,573,535
Total Proved Plus Probable	5,022,051	524,133	1,073,150	381,673	34,613	3,008,482	588,131	2,420,352
Proved Plus Probable Plus Possible	8,116,226	838,365	1,749,319	425,121	45,023	5,058,398	1,154,418	3,903,981
Heavy Oil Business Unit (Canada)								
Total Proved Plus Probable	4,636,904	870,592	1,826,310	691,792	8,705	1,239,504	315,250	924,255
Proved Plus Probable Plus Possible	5,360,005	1,094,380	1,925,634	681,956	9,590	1,648,446	417,163	1,231,283
Canada Total								
Total Proved	3,154,371	342,248	655,330	289,109	27,353	1,840,331	266,796	1,573,535
Total Proved Plus Probable	9,658,955	1,394,725	2,899,460	1,073,465	43,318	4,247,986	903,380	3,344,607
Proved Plus Probable Plus Possible	13,476,231	1,932,745	3,674,953	1,107,077	54,613	6,706,844	1,571,580	5,135,264
Latin American Business Unit (Colombia)⁽¹⁾	(US M\$)	(US M\$) ⁽²⁾	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)	(US M\$)
Total Proved	1,724,166	171,844	217,003	132,815	1,124	1,201,380	241,111	960,269
Total Proved Plus Probable	2,571,624	252,713	272,099	232,883	1,414	1,812,515	455,109	1,357,406
Proved Plus Probable Plus Possible	3,941,153	398,476	420,903	380,929	2,127	2,738,718	759,594	1,979,124
Canada & Colombia⁽¹⁾⁽³⁾	(CDN M\$)	(CDN M\$) ⁽²⁾	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)	(CDN M\$)
Total Proved	5,265,785	552,688	921,072	451,754	28,729	3,311,541	562,061	2,749,480
Total Proved Plus Probable	12,808,166	1,704,197	3,232,672	1,358,654	45,050	6,467,592	1,460,706	5,006,886
Proved Plus Probable Plus Possible	18,302,567	2,420,719	4,190,391	1,573,563	57,218	10,060,678	2,501,779	7,558,899

Notes:

⁽¹⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values".

⁽²⁾ Royalties include net profits interest payable on the Corcel and Joropo blocks.

⁽³⁾ U.S. dollars are converted into Canadian dollars using an exchange rate of \$1.2246.

* Table may not add due to rounding.

**FUTURE NET REVENUE
BY PRODUCTION GROUP
FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2008**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES	FUTURE NET REVENUE UNIT VALUE BEFORE INCOME TAXES ⁽¹⁾
		(Discounted at 10%/year) (CDN M\$)	(Discounted at 10%/year) (CDN\$/boe)
Canadian Business Unit (Canada)			
Total Proved	Light and Medium Crude Oil ⁽²⁾	991,507	31.48
	Natural Gas ⁽³⁾	76,885	15.28
Total Proved Plus Probable	Light and Medium Crude Oil ⁽²⁾	1,386,150	29.60
	Natural Gas ⁽³⁾	103,749	14.52
Proved Plus Probable Plus Possible	Light and Medium Crude Oil ⁽²⁾	1,874,508	27.28
	Natural Gas ⁽³⁾	126,513	13.48
Heavy Oil Business Unit (Canada)			
Total Proved Plus Probable	Bitumen	294,337	5.23
Proved Plus Probable Plus Possible	Bitumen	400,413	6.45
Canada Total			
Total Proved	Light and Medium Crude Oil ⁽²⁾	991,507	31.48
	Natural Gas ⁽³⁾	76,885	15.28
Total Proved Plus Probable	Light and Medium Crude Oil ⁽²⁾	1,386,150	29.60
	Natural Gas ⁽³⁾	103,749	14.52
	Bitumen	294,337	5.23
Proved Plus Probable Plus Possible	Light and Medium Crude Oil ⁽²⁾	1,874,508	27.28
	Natural Gas ⁽³⁾	126,513	13.48
	Bitumen	400,413	6.45
Latin American Business Unit (Colombia) ⁽⁴⁾			
Total Proved	Light and Medium Crude Oil ⁽²⁾	(US M\$) 831,923	(US\$/bbl) 35.98
	Light and Medium Crude Oil ⁽²⁾	1,229,407	36.34
Proved Plus Probable Plus Possible	Light and Medium Crude Oil ⁽²⁾	1,808,561	35.89
Canada & Colombia ⁽⁴⁾⁽⁵⁾			
Total Proved	Light and Medium Crude Oil ⁽²⁾	(CDN M\$) 2,010,280	(CDN\$/boe) 37.95
	Natural Gas ⁽³⁾	76,885	15.28
Total Proved Plus Probable	Light and Medium Crude Oil ⁽²⁾	2,891,682	36.92
	Natural Gas ⁽³⁾	103,749	14.52
	Bitumen	294,337	5.23
Proved Plus Probable Plus Possible	Light and Medium Crude Oil ⁽²⁾	4,089,272	35.38
	Natural Gas ⁽³⁾	126,513	13.48
	Bitumen	400,413	6.45

Notes:

⁽¹⁾ Unit values are based on net reserve volumes.

⁽²⁾ Including natural gas liquids, solution gas and other by-products.

⁽³⁾ Including by-products but excluding solution gas from oil wells.

⁽⁴⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values".

⁽⁵⁾ U.S. dollars are converted into Canadian dollars using an exchange rate of \$1.2246.

* Table may not add due to rounding.

**SUMMARY OF PRICING ASSUMPTIONS
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS**

Business Unit	Evaluator	Year	West Texas Intermediate Crude Oil at Cushing Oklahoma \$US/bbl	Inflation Rates %/Year	Exchange Rate \$US/\$Cdn	Light, Sweet Crude Oil		Natural Gas	Alberta Natural Gas Liquids		
						40° API at Edmonton \$Cdn/bbl	29.3° API at Cromer \$Cdn/bbl	AECO Gas Price \$Cdn/mmbtu	Edmonton Butane \$Cdn/bbl	Edmonton Pentanes Plus \$Cdn/bbl	
Canadian	Sproule	2009	53.73	2.0	0.80	65.35	58.16	6.82	51.15	66.93	
		2010	63.41	2.0	0.85	72.78	66.23	7.56	54.25	74.54	
		2011	69.53	2.0	0.85	79.95	72.76	7.84	59.59	81.88	
		2012	79.59	2.0	0.90	86.57	79.65	8.38	64.53	88.66	
		2013	92.01	2.0	0.95	94.97	87.38	9.20	70.79	97.27	
		Thereafter	Various escalation rates								

Business Unit	Evaluator	Year	West Texas Intermediate Crude Oil at Cushing Oklahoma \$US/bbl	Inflation Rates %/Year	Colombia Plant Gate Prices		
					Orito \$US/bbl	Neiva \$US/bbl	Corcel \$US/bbl
Latin American	D&M	2009	57.00	-	52.60	48.30	55.00
		2010	69.53	3.0	65.13	60.83	67.53
		2011	76.38	3.0	71.99	67.68	74.38
		2012	86.99	2.5	82.59	78.29	84.99
		2013	94.74	2.5	90.34	86.04	92.74
		Thereafter	+2.5% per year	2.5			

Business Unit	Evaluator	Year	West Texas Intermediate Crude Oil at Cushing Oklahoma \$US/bbl	Inflation Rates %/Year	Exchange Rate \$US/\$Cdn	Alberta Natural Gas															
						Edmonton MSW \$Cdn/bbl	WCS at Hardisty \$Cdn/bbl	Bow River Hvy at Hardisty \$Cdn/bbl	LLB at Hardisty \$Cdn/bbl	Edmonton C5+ \$Cdn/bbl	Diluent at Edmonton \$Cdn/bbl	Diluent at Fieldgate \$Cdn/bbl	Edmonton SSB SCO \$Cdn/bbl	Edmonton Premium SCO \$Cdn/bbl	Dilbit at Hardisty \$Cdn/bbl	Netback Bitumen at Fieldgate \$Cdn/bbl	Dilbit at Edmonton \$Cdn/bbl	Netback Bitumen at Fieldgate \$Cdn/bbl	Natural Gas at AECO - C \$Cdn/Mmbtu	Natural Gas at Fieldgate \$Cdn/Mmbtu	Alberta Power \$Cdn/MWh
Heavy Oil	McDaniel	2009	60.00	2.0	0.85	69.60	53.65	54.80	53.40	71.60	76.70	78.18	73.60	74.31	53.65	41.31	53.08	40.43	7.40	7.15	81.80
		2010	71.40	2.0	0.85	83.00	63.84	65.30	63.70	85.00	91.50	93.01	85.00	85.73	63.84	49.48	63.17	48.45	8.00	7.74	86.85
		2011	83.20	2.0	0.90	91.40	70.26	72.00	70.10	93.50	101.46	103.00	92.90	93.64	70.26	54.33	69.52	53.20	8.45	8.19	90.79
		2012	90.20	2.0	0.95	93.90	72.16	73.90	72.00	96.00	104.12	105.69	94.90	95.66	72.16	55.86	71.40	54.70	8.80	8.53	94.00
		2013	97.40	2.0	1.00	96.30	74.02	75.90	73.90	98.50	106.78	108.38	96.30	97.07	74.02	57.33	73.24	56.14	9.05	8.78	96.46
		Thereafter	+2% per year	2.0	1.00	Various escalation rates															

Note:

Weighted average historical prices realized by the Company for the year ended December 31, 2008 in Canada, were \$8.06/mcf for natural gas (includes negative impact of physical gas sale contract) and \$92.80/bbl for crude oil and NGL (excluding hedging activities). In Colombia, light and medium crude oil prices averaged US\$82.27/bbl (excluding hedging activities). Prices with respect to the Latin American Business Unit were provided by D&M, Sproule provided the prices for the Canadian Business Unit and prices with respect to the Heavy Oil Business Unit were provided by McDaniel.

**RECONCILIATION OF COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

FACTORS	Light and Medium Oil			Natural Gas ⁽¹⁾			Natural Gas Liquids			Bitumen
	Gross Proved (mdbl)	Gross Probable (mdbl)	Gross Proved Plus Probable (mdbl)	Gross Proved (mmcf)	Gross Probable (mmcf)	Gross Proved Plus Probable (mmcf)	Gross Proved (mdbl)	Gross Probable (mdbl)	Gross Proved Plus Probable (mdbl)	Gross Proved Plus Probable (mdbl)
Canadian and Heavy Oil Business Units (Canada)										
December 31, 2007	13,250	8,490	21,740	31,905	11,949	43,854	866	554	1,420	25,476
Extensions	13,420	6,201	19,622	3,762	1,534	5,296	683	285	968	43,506
Technical Revisions	2,460	(2,227)	233	(1,268)	(1,168)	(2,436)	94	(81)	13	-
Acquisitions	6,173	2,117	8,290	18,554	7,812	26,366	1,052	378	1,430	-
Production	(5,355)	-	(5,355)	(5,043)	-	(5,043)	(164)	-	(164)	-
December 31, 2008	29,948	14,581	44,529	47,910	20,127	68,037	2,532	1,136	3,667	68,982
Latin American Business Unit (Colombia) ⁽²⁾										
December 31, 2007	20,597	16,380	36,977	-	-	-	-	-	-	-
Technical Revisions	(95)	(5,916)	(6,011)	-	-	-	164	136	300	-
Discoveries	7,451	1,014	8,465	-	-	-	396	70	466	-
Economic Factors	675	(9)	666	-	-	-	-	-	-	-
Production	(4,014)	-	(4,014)	-	-	-	-	-	-	-
December 31, 2008	24,614	11,469	36,083	-	-	-	560	206	766	-
Canada & Colombia ⁽²⁾										
December 31, 2007	33,847	24,870	58,717	31,905	11,949	43,854	866	554	1,420	25,476
Extensions	13,420	6,201	19,622	3,762	1,534	5,296	683	285	968	43,506
Technical Revisions	2,365	(8,143)	(5,778)	(1,268)	(1,168)	(2,436)	258	55	313	-
Acquisitions	13,624	3,131	16,755	18,554	7,812	26,366	1,448	448	1,896	-
Economic Factors	675	(9)	666	-	-	-	-	-	-	-
Production	(9,369)	-	(9,369)	(5,043)	-	(5,043)	(164)	-	(164)	-
December 31, 2008	54,562	26,050	80,612	47,910	20,127	68,037	3,092	1,342	4,433	68,982

Notes:

⁽¹⁾ Includes associated, non-associated, and solution gas.

⁽²⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values".

* Table may not add due to rounding.

**UNDEVELOPED RESERVES
FORECAST PRICES AND COSTS**

The following table sets out the volume of the Company's proved undeveloped and probable undeveloped reserves over the most recent three financial years and the amount of reserves first attributed in each of those years.

RESERVES CATEGORY	LIGHT AND MEDIUM OIL		NATURAL GAS ⁽¹⁾		NATURAL GAS LIQUIDS ⁽²⁾		BITUMEN	
	Gross (mdbl)		Gross (mmcf)		Gross (mdbl)		Gross (mdbl)	
	First Attributed	Booked	First Attributed	Booked	First Attributed	Booked	First Attributed	Booked
Canadian and Heavy Oil Business Units (Canada)								
Proved Undeveloped								
Prior to 2006	200	200	19,435	19,435	50	50	-	-
2006	281	481	1,466	12,190	-	20	-	-
2007	6,777	7,192	2,276	14,227	390	426	-	-
2008	7,457	9,757	2,105	14,403	373	520	-	-
Probable Undeveloped								
Prior to 2006	-	246	493	15,855	1	52	-	-
2006	430	676	235	3,433	-	24	25,290	25,290
2007	6,282	6,474	3,338	6,647	392	404	186	25,476
2008	4,861	7,334	1,696	6,735	235	380	43,506	68,982
Latin American Business Unit (Colombia) ⁽³⁾								
Proved Undeveloped								
Prior to 2006	3,910	7,411	-	-	-	-	-	-
2006	2,761	9,616	-	-	-	-	-	-
2007	5,620	11,479	-	-	-	-	-	-
2008	3,250	10,385	-	-	560	560	-	-
Probable Undeveloped								
Prior to 2006	2,681	6,503	-	-	-	-	-	-
2006	4,697	10,968	-	-	-	-	-	-
2007	8,163	16,380	-	-	-	-	-	-
2008	3,905	11,469	-	-	206	206	-	-
Canada & Colombia ⁽³⁾								
Proved Undeveloped								
Prior to 2006	4,110	7,611	19,435	19,435	50	50	-	-
2006	3,042	10,097	1,466	12,190	-	20	-	-
2007	12,397	18,671	2,276	14,227	390	426	-	-
2008	10,707	20,142	2,105	14,403	933	1,080	-	-
Probable Undeveloped								
Prior to 2006	2,681	6,749	493	15,855	1	52	-	-
2006	5,127	11,644	235	3,433	-	24	25,290	25,290
2007	14,445	22,854	3,338	6,647	392	404	186	25,476
2008	8,766	18,803	1,696	6,735	441	586	43,506	68,982

Notes:

⁽¹⁾ Includes associated, non-associated, and solution gas.

⁽²⁾ Probable undeveloped amounts include heavy oil in 2006.

⁽³⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Reserves and Net Present Values".

* Table may not add due to rounding.

FUTURE DEVELOPMENT COSTS ⁽¹⁾⁽²⁾

		FORECAST PRICES AND COSTS	
		Total Proved Reserves	Total Proved Plus Probable Reserves
YEAR		(CDN M\$)	(CDN M\$)
Canadian Business Unit (Canada)			
	2009	234,390	288,776
	2010	54,472	92,650
	2011	-	-
	2012	-	-
	2013	-	-
	Thereafter	247	247
	Total undiscounted	289,109	381,673
	Total discounted at 10%	269,858	353,840
Heavy Oil Business Unit (Canada)			
	2009	-	5,100
	2010	-	211,409
	2011	-	144,006
	2012	-	2,706
	2013	-	2,760
	Thereafter	-	325,811
	Total undiscounted	-	691,792
	Total discounted at 10%	-	406,635
Canada Total			
	2009	234,390	293,876
	2010	54,472	304,059
	2011	-	144,006
	2012	-	2,706
	2013	-	2,760
	Thereafter	247	326,058
	Total undiscounted	289,109	1,073,465
	Total discounted at 10%	269,858	760,475
Latin American Business Unit (Colombia) ⁽³⁾			
		(US M\$)	(US M\$)
	2009	53,100	105,800
	2010	38,976	51,530
	2011	28,893	57,784
	2012	11,846	17,769
	2013	-	-
	Thereafter	1,124	1,414
	Total undiscounted	133,939	234,297
	Total discounted at 10%	115,145	202,624
Canada & Colombia ⁽³⁾⁽⁴⁾			
		(CDN M\$)	(CDN M\$)
	2009	299,416	423,439
	2010	102,202	367,163
	2011	35,382	214,768
	2012	14,507	24,466
	2013	-	2,760
	Thereafter	1,623	327,790
	Total undiscounted	453,131	1,360,385
	Total discounted at 10%	410,865	1,008,608

Notes:

⁽¹⁾ The table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted.

⁽²⁾ Future development costs are expected to be funded by internally generated cash flow, and from a combination of equity financing and debt, the costs of which are not expected to have an effect on the reserves or future net revenue.

⁽³⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values".

⁽⁴⁾ U.S. dollars are converted into Canadian dollars using an exchange rate of \$1.2246.

* Table may not add due to rounding.

2009 PRODUCTION ESTIMATES

The following table sets out the volume of the Company's production estimated for the year ended December 31, 2009 which is reflected in the estimate of future net revenue disclosed in the tables contained in this AIF. Heavy Oil Business Unit bitumen volumes in the McDaniel Report are not forecast to start production until 2011.

RESERVES CATEGORY	LIGHT AND MEDIUM OIL	NATURAL GAS ⁽¹⁾	NATURAL GAS LIQUIDS	OIL EQUIVALENT
	Gross (bbl/d)	Gross (mcf/d)	Gross (bbl/d)	Gross (boe/d)
Canadian Business Unit (Canada)				
Proved Producing				
Bakken (Southeast Saskatchewan)	12,027	4,453	835	13,604
Others	389	9,311	140	2,081
Total Proved Producing	12,416	13,764	975	15,685
Total Proved				
Bakken (Southeast Saskatchewan)	15,634	5,759	1,080	17,674
Others	418	13,825	250	2,972
Total Proved	16,052	19,584	1,330	20,646
Total Proved Plus Probable				
Bakken (Southeast Saskatchewan)	16,703	6,142	1,151	18,878
Others	530	15,782	300	3,460
Total Proved Plus Probable	17,233	21,924	1,451	22,338
Proved Plus Probable Plus Possible				
Bakken (Southeast Saskatchewan)	17,371	6,477	1,215	19,665
Others	563	16,721	307	3,657
Proved Plus Probable Plus Possible	17,934	23,198	1,522	23,322
Latin American Business Unit (Colombia) ⁽²⁾				
Proved Producing				
Corcel	12,660	-	-	12,660
Orito	3,071	-	-	3,071
Neiva	386	-	-	386
Total Proved Producing	16,117	-	-	16,117
Total Proved				
Corcel	13,238	-	526	13,764
Orito	3,797	-	-	3,797
Neiva	1,485	-	-	1,485
Total Proved	18,520	-	526	19,046
Total Proved Plus Probable				
Corcel	14,896	-	638	15,534
Orito	4,416	-	-	4,416
Neiva	3,197	-	-	3,197
Total Proved Plus Probable	22,509	-	638	23,147
Proved Plus Probable Plus Possible				
Corcel	18,994	-	918	19,912
Orito	4,449	-	-	4,449
Neiva	4,575	-	-	4,575
Proved Plus Probable Plus Possible	28,018	-	918	28,936
Canada & Colombia ⁽²⁾				
Proved Producing	28,533	13,764	975	31,802
Total Proved	34,572	19,584	1,856	39,692
Total Proved Plus Probable	39,742	21,924	2,089	45,485
Proved Plus Probable Plus Possible	45,952	23,198	2,440	52,258

Notes:

⁽¹⁾ Includes associated, non-associated, and solution gas.

⁽²⁾ All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the subsidiaries of the Company have been consolidated into the Company's accounts. Note that as at December 31, 2008, the Company held an 76.5% interest in Petrominerales. Petrominerales holds all of the Colombian assets of the Company, described herein as the Latin American Business Unit. For further discussion see "Statement of Reserves Data and Other Oil and Gas Information - Ownership of Petrominerales" and "Minority Shareholders' Interests in Latin American Business Unit Reserves and Net Present Values".

* Table may not add due to rounding.

Marketing

The majority of the Company's Canadian production is sold to a large international marketing company, while Colombian production is predominantly sold to Ecopetrol, the Colombian national oil company. Sales to individual counterparties exceeding 15% of consolidated revenues for the years ended December 31, 2007 and 2008 are broken down by product group as follows:

	Sales as % of consolidated revenues	
	2008	2007
Crude oil		
Trafigura (Canada)	55%	41%
Ecopetrol (Colombia)	37%	46%

Production

The following table sets forth the Company's conventional average daily production volumes, by major producing region and on a consolidated basis, for the three and twelve month periods ended December 31, 2008.

	<u>Lt/Med and NGL (bbl)</u>		<u>Gas (mcf)</u>		<u>Total (boe)</u>	
	2008		2008		2008	
	<u>Average</u>	<u>Q4 2008</u>	<u>Average</u>	<u>Q4 2008</u>	<u>Average</u>	<u>Q4 2008</u>
Canada						
SE Saskatchewan	14,704	19,195	1,669	2,338	14,982	19,585
Jumpbush, Alberta	20	21	5,072	4,490	865	769
Others	645	625	7,695	7,770	1,928	1,920
Total Canada	15,369	19,841	14,436	14,598	17,775	22,274
Colombia						
Corcel	7,562	13,023	-	-	7,562	13,023
Orito	2,946	1,844	-	-	2,946	1,844
Neiva & others	459	477	-	-	459	477
Total Colombia	10,967	15,344	-	-	10,967	15,344
Total Company	26,336	35,185	14,436	14,598	28,742	37,618

Notes:

1. NGL have been included with light/medium oil, as they are not considered to be material. NGL represent approximately six percent of the Company's Canadian total proved plus probable reserves.

Oil and Gas Wells

The following table summarizes Petrobank's interests, by region and on a consolidated basis, as at December 31, 2008, in oil and natural gas wells which are producing or which are considered capable of production. All wells considered capable of production have been standing for a period of less than one year, are within economic distance of transportation facilities and are classified as proved developed non-producing reserves in the Sproule and D&M Reports, except for the Whitesands wells. All of the Company's properties are located onshore.

	Producing				Non-Producing			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan	402	326	1	1	15	13	-	-
Alberta	45	20	181	123	-	-	1	1
British Columbia	-	-	29	22	-	-	2	2
Whitesands (Alberta) ⁽¹⁾	3	3	-	-	-	-	-	-
Canada	450	349	211	146	15	13	3	3
Corcel	6	6	-	-	-	-	-	-
Joropo	1	1	-	-	-	-	-	-
Las Aguilas	-	-	-	-	1	1	-	-
Neiva	65	45	-	-	-	-	-	-
Orito	68	54	-	-	4	3	-	-
Colombia	140	106	-	-	5	4	-	-
Total Company	590	455	211	146	20	17	3	3

Notes:

- Whitesands holds all the non-conventional oil sands (bitumen) assets of the Company, described herein as the Heavy Oil Business Unit.

Land Holdings - Consolidated

The land holdings of the Company, including those that are undeveloped, by region and on a consolidated basis, as at December 31, 2008, are set forth in the following table (in 000s of acres unless otherwise noted). For the land holdings of Petrominerales by region, see "*Land Holdings – Latin American Business Unit*":

Area	Developed		Undeveloped		Total		Avg.
	Gross	Net	Gross	Net	Gross	Net	WI%
Saskatchewan	48	39	211	192	259	231	89
Alberta	86	54	184	135	270	189	70
British Columbia	39	28	142	101	181	129	71
Other	-	-	40	36	40	36	90
Canadian Business Unit	173	121	577	464	750	585	78
Heavy Oil Business Unit	1	1	72	71	73	72	99
Latin American Business Unit	28	23	4,587	3,392	4,615	3,415	74
Total Company	202	145	5,236	3,927	5,438	4,072	75

Provincial governments in Canada grant rights to explore for and produce oil and natural gas under leases, licenses and permits, which may be continued, indefinitely by producing under the lease. Accordingly, to preserve this acreage the Company is committed to bring wells on production.

The Company expects that rights to explore, develop and exploit 17,000 net acres of its undeveloped land in Canada will expire by December 31, 2009.

Land Holdings – Latin American Business Unit

The land holdings of Petrominerales, including those that are undeveloped as of December 31, 2008, are set forth in the following table (in 000s of acres unless otherwise noted):

<u>Country</u>	<u>Developed</u>		<u>Undeveloped</u>		<u>Total</u>		<u>Average</u>
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Working Interest %</u>
Colombia	28	23	1,950	1,942	1,978	1,965	99
Peru	-	-	2,637	1,450	2,637	1,450	55
Total	28	23	4,587	3,392	4,615	3,415	74

Undeveloped acreage includes rights granted pursuant to Exploration Contracts and License Contracts (including those contracts subject to finalization), which require certain work commitments. If Petrominerales elects not to proceed with additional work commitments, all or a portion of this acreage may revert to the respective oil and gas authority. On March 6, 2009, Petrominerales notified the ANH of its intention to relinquish 71,130 acres of the Joropo Block, retaining 1,127 acres surrounding the Ojo de Tigre-2 and Ojo de Tigre-3 wells. The land holdings in Peru relate to Block 126. Petrominerales has been recognized as an operator in Peru by PeruPetro, however we have not received final approval on the 55% assignment of the Block 126 License Contract. The approval is expected to be received in due course from the Peruvian Ministry of Energy and Mines.

Forward Contracts and Future Commitments

See Note 15, “*Financial Instruments and Financial Risk Management*”, and Note 18, “*Commitments and Contingencies*”, to the Company’s December 31, 2008 consolidated financial statements, which information is incorporated herein by reference and can be found on SEDAR at www.sedar.com.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs were estimated for all legal obligations associated with the retirement of long-lived tangible assets such as wells, facilities and plants based on market prices or on the best information available where no market price was available. For obligations in Canada, the estimated costs are then inflated at two percent over time until the actual retirement is expected to occur.

As at December 31, 2008, the Company expected to incur abandonment and reclamation costs in respect of 727 net wells in Canada.

Petrominerales’ liability for abandonment and reclamation costs in Colombia is different than that applicable to the Company’s Canadian operations. Abandonment and reclamation costs were estimated for all legal obligations associated with the retirement of long-lived tangible assets such as wells, facilities and plants based on market prices or on the best information available where no market price was available. The estimated costs are then inflated at four percent over time until the actual retirement is expected to occur. In Colombia, Ecopetrol maintains ownership of all wells once the IPCs expire. Until expiry, Petrominerales is potentially liable for abandonment and reclamation costs for all wells drilled or intervened by Petrominerales. As of December 31, 2008, 80 wells under the IPCs and 11 exploration wells under the ANH exploration contracts have either been drilled or intervened, however Petrominerales expects to incur costs on only 35 wells (30 net) due to the fact that most wells at Orito and Neiva are expected to produce beyond the term of the IPCs.

The total abandonment and reclamation costs net of salvage values of all the Company’s operations, on a consolidated basis, are estimated to be \$87.5 million (Canada - \$58.7 million; Colombia - US\$23.5 million) on an undiscounted basis and \$11.5 million (Canada - \$6.4 million; Colombia -

US\$4.2 million) discounted at 10 percent. In the next three financial years the Company anticipates that approximately \$1.4 million (Canada - \$0.8 million; Colombia - US\$0.5 million) on an undiscounted basis and \$1.2 million (Canada - \$0.6 million; Colombia - US\$0.5 million) discounted at 10 percent will be incurred on abandonment and reclamation costs.

The calculation of future net revenue in the future prices and costs tables contained herein have excluded \$65.3 million (Canada - \$39.1 million; Colombia - US\$21.4 million) on an undiscounted basis and \$4.6 million (Canada - \$2.0 million; Colombia - US\$2.1 million) discounted at 10 percent from the Company's estimates, as these calculations do not reflect any costs for abandonment and reclamation for facilities and wells for which no proved reserves have been attributed and does not include any costs for abandonment and reclamation activities for the Orito and Neiva blocks in Colombia.

Tax Horizon

In Canada, Petrobank's tax pools shelter it from paying current cash income taxes. Based on the Sproule Report and the Company's current exploration and development plans, Petrobank does not expect to pay income tax in Canada until 2010 or later.

In Colombia, Petrominerales was taxable in 2008. In certain prior years, the Company's tax pools sheltered it from paying current cash income taxes. The D&M Report anticipates an ordinary cash income tax liability in Colombia in 2009. Expenditures on productive, real assets in Colombia generate a 40 percent enhanced tax allowance deductible immediately and accordingly may reduce taxes payable in future periods.

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2008, separated into its three business units. (See "Acquisitions" for costs incurred in respect of corporate acquisitions.)

(000s)	CBU ⁽¹⁾	LABU ⁽²⁾	HBU ⁽³⁾	Total
Drilling and completions	\$ 315,970	\$ 191,122	\$ 16,485	\$ 523,577
Facilities	83,519	64,462	22,042	170,023
Land	130,283	-	75	130,358
Seismic	4,426	22,953	2,389	29,768
Pilot capital ⁽⁴⁾	-	-	28,505	28,505
Other ⁽⁵⁾	11,635	3,211	12,836	27,682
Total capital expenditures	\$ 545,833	\$ 281,748	\$ 82,332	\$ 909,913

Notes:

1. CBU includes \$130.3 million of land acquisitions, \$17.7 million of exploration expenditures and \$397.8 million of development expenditures. Petrobank also acquired two companies in 2008 for a total value including net debt and working capital acquired or assumed of \$391.5 million, of which \$258.5 million related to proved properties while the remaining \$133.0 million related to unproved properties.
2. LABU includes \$92.9 million of exploration expenditures and \$188.8 million of development expenditures.
3. All HBU expenditures relate to unproved properties.
4. Pilot capital includes: well workovers; operating costs to manage H₂S; gas, water and oil analysis; sand and waste water disposal; and additional laboratory and research related costs; net of revenues received
5. CBU and LABU include capitalized salaries and office furniture. HBU includes \$9.4 million of capitalized cash interest and \$3.4 million of non-cash accretion.

Exploration and Development

The following table summarizes the gross and net exploratory and development wells in which the Company and its subsidiaries participated during the year ended December 31, 2008.

	<u>Exploration</u>		<u>Development</u>		<u>Total</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Canadian Business Unit						
Oil	4	3.0	220	183.9	224	186.9
Natural Gas	3	2.0	1	-	4	2.0
Service Wells	-	-	4	2.9	4	2.9
Successful	7	5.0	225	186.8	232	191.8
Dry	1	1.0	1	1.0	2	2.0
Total CBU	8	6.0	226	187.8	234	193.8
Success Rate	88%	83%	100%	99%	99%	99%
Latin American Business Unit						
Oil	5	5.0	15	11.9	20	16.9
Service Wells	-	-	2	2.0	2	2.0
Successful	5	5.0	17	13.9	22	18.9
Dry	3*	3.0*	-	-	3*	3.0*
Total LABU	8	8.0	17	13.9	25	21.9
Success Rate	63%	63%	100%	100%	88%	86%

*Includes the Ojo de Tigre-3 well, which produced 100% water from a 17 foot interval perforated in the Carbonera formation. Upon further evaluation, the presence of poor cement bond in the well is believed to have caused the water influx. A remedial cement squeeze will be required to properly isolate the prospective zones in the well. Due to the narrow drilling window during the Llanos Basin dry season, the work will be conducted in 2009.

The Company and its subsidiaries' exploration and development plans are discussed under the heading "*Business of the Company*".

Production History

Production

The following table shows the Company and its subsidiaries' average working interest production volumes before deduction of royalties payable to others and average netbacks received for each of the last four fiscal quarters by product type. See "*Overview of the Business and Principal Properties*" for production volumes by major area:

	<u>Three Months Ended</u>				<u>Year Ended</u>
	<u>Mar 31, 2008</u>	<u>June 30, 2008</u>	<u>Sept 30, 2008</u>	<u>Dec 31, 2008</u>	<u>Dec 31, 2008</u>
Average daily production ⁽¹⁾					
CBU – light / medium oil and NGL (bbl/d)	11,351	14,205	16,024	19,841	15,369
CBU – natural gas (mcf/d)	15,229	13,871	14,047	14,598	14,436
Total CBU conventional (boe/d)	13,889	16,517	18,365	22,274	17,775
LABU – light / medium oil (bbl/d)	8,635	7,339	12,485	15,344	10,967
Total Company (boe/d)	22,524	23,856	30,850	37,618	28,742

Notes:

1. NGL have been included with light/medium oil as they are not considered to be material. NGL represent approximately six percent of the Company's Canadian total proved plus probable reserves.

Canadian Business Unit Netback by Product

Light/Medium Crude Oil and NGL Netback (\$ per bbl)

	Three Months Ended				Year Ended
	Mar 31, 2008	June 30, 2008	Sept 30, 2008	Dec 31, 2008	Dec 31, 2008
Average price received ⁽¹⁾	91.87	117.64	115.11	57.71	92.80
Royalties	6.44	11.83	13.36	8.90	10.29
Operating costs ⁽²⁾	10.25	9.55	9.56	8.68	9.40
Netback ⁽³⁾	75.18	96.26	92.19	40.13	73.11

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.

Natural Gas Netback (\$ per mcf)

	Three Months Ended				Year Ended
	Mar 31, 2008	June 30, 2008	Sept 30, 2008	Dec 31, 2008	Dec 31, 2008
Average price received ⁽¹⁾	7.73	9.83	7.94	6.86	8.06
Royalties	1.35	1.81	1.38	1.06	1.39
Operating costs ⁽²⁾	0.89	0.83	0.66	0.77	0.79
Netback	5.49	7.19	5.90	5.03	5.88

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.

Latin American Business Unit Netback

Light and Medium Crude Oil Netback (\$ per bbl)

	Three Months Ended				Year Ended
	Mar 31, 2008	June 30, 2008	Sept 30, 2008	Dec 31, 2008	Dec 31, 2008
Average price received ⁽¹⁾	86.53	115.77	110.53	54.93	87.15
Royalties	8.25	11.11	11.71	4.68	8.46
Operating costs ⁽²⁾	10.86	10.86	8.38	7.80	9.08
Netback ⁽³⁾	67.42	93.80	90.44	42.45	69.61

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as Ecopetrol operating fees, field staff salaries, repairs and maintenance, overhead fees and other costs.
3. Excludes hedging activities.

Taxes in Colombia

In 2008, Petrominerales was taxable in Colombia. In certain prior years, the Company's tax pools sheltered it from paying current cash income taxes. The D&M Report anticipates an ordinary cash income tax liability in Colombia in 2009. Expenditures on productive, real assets in Colombia generate a

40 percent enhanced tax allowance deductible immediately (see “*Taxes*”) and accordingly may reduce taxes payable in future periods.

Petrominerales’ pre-tax income from Colombian sources as defined under Colombian law is subject to Colombian income taxes at a statutory rate of 33 percent. Costs related to the acquisition or construction of real fixed assets are subject to a special tax deduction in the year of acquisition equal to 40 percent. Petrominerales’ Colombian entities are also subject to an equity tax, which is 1.2 percent of 2006 equity levels.

A "presumptive" minimum income tax exists which may apply in years with little or no income. When applicable, presumptive income tax is calculated as 33 percent of three percent of prior year net equity. The excess may be carried forward as a credit for five years and recovered against future cash taxes otherwise payable. Tax losses may be carried forward without limitations to offset taxable income.

As at December 31, 2008, the Company had tax pools in Colombia totalling US\$399.7 million.

RISK FACTORS

Investing in securities of Petrobank involves inherent risks. The risks described below are not the only ones facing the Company. Additional risks not presently known to the Company or that the Company currently deems immaterial may also impair the Company's business operations. If any of the following risks actually occur, Petrobank's business, financial condition and operating results could be materially and adversely affected.

An investment in Petrobank may be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development. Oil and gas operations involve many risks, which even a combination of experience and knowledge, and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Nature of the Business

An investment in Petrobank should be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas in Canada and in foreign countries. The Company has not paid any dividends on its common shares and is unlikely to pay dividends in the immediate or foreseeable future. Also, oil and gas operations involve many risks, which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Commodity Price Volatility

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Petrobank's net production revenue and overall value and could result in ceiling test write-downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Petrobank's reserves. Petrobank might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Petrobank's net production revenue causing a reduction in its oil and gas acquisition and development activities. A substantial material decline in prices from historical average prices could reduce the Company's ability to refinance its outstanding subordinated notes and may result in a reduced

borrowing base under credit facilities available to the Company and possibly require that a portion of the Company's bank debt be repaid.

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, known as hedging, 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. The Company could also be subject to margin requirements associated with certain hedging instruments.

Financial Resources

The Company's cash flow from operations may not be sufficient to fund its ongoing activities and implement its business plans. From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions along with the Company's ongoing operations may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Depending on future exploration and development plans, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms. Failure to obtain such financing on a timely basis could cause the Company to forfeit or forego various opportunities. Credit markets throughout the world have tightened recently which could limit the Company's ability to access incremental debt. As at December 31, 2008, the Company had positive cash flows from operations, cash and cash equivalents and restricted cash totalling \$107.7 million, a Canadian credit facility with \$64.3 million of available capacity and a US\$80 million credit facility available to Petrominerales.

Reserves

The Company's future reserves and production and, therefore, cash flows are highly dependent upon success in exploiting the Company's current reserves base and acquiring or discovering additional reserves. Without reserves additions through exploration, acquisition or development activities, Petrobank's reserves and production will decline over time. Exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient to fund the Company's capital expenditures and external sources of capital become limited or unavailable, Petrobank's ability to make the necessary capital investments to maintain oil and natural gas reserves will be impaired. Costs to find and develop or acquire additional reserves also depend on success rates, which vary over time.

Reliance on Third Party Operators and Key Personnel

To the extent that the Company is not the operator of its properties, including in Colombia where Ecopetrol, the Colombian national oil company, operates Petrobank's production at Orito and Neiva, it will be dependent upon other guarantors or third parties operations for the timing of activities and will be largely unable to control the activities of such operators. In addition, the Company's success depends, to a significant extent, upon management and key employees. The loss of key employees could have a negative effect on the Company. Attracting and retaining additional key personnel will assist in the expansion of the Company's business. The Company faces significant competition for skilled personnel. There is no assurance that the Company will successfully attract and retain personnel required to continue to expand its business and to successfully execute its business strategy.

Strong Competition

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Petrobank's competitive position depends on its geological, geophysical and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Petrobank competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Petrobank also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Petrobank also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. In addition, equipment and other materials necessary to construct production and transmission facilities may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies will also provide competition for Petrobank.

The Company's Oil and Natural Gas Production Could Vary Significantly From Reported Reserves

The Company's reserve evaluations have been prepared in accordance with National Instrument 51-101 "*Standards of Disclosure for Oil and Gas Activities*". There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserves information set forth in this Annual Information Form represent estimates only. The reserves from the Company's properties have been independently evaluated by McDaniel, Sproule and D&M in their respective reports. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based, in part, on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Canadian GAAP requires that management apply certain accounting policies and make certain estimates and assumptions, which affect reported amounts in the consolidated financial statements of the Company. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Company's shares.

Under Canadian GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a ceiling-test, which is based upon estimated future net cash flow from reserves. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not

assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

The Company Might Encounter Operating Hazards

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, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Petrobank maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Petrobank could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

The Company's Whitesands project entails risks incremental to those of conventional oil and gas operations. Although other operators have utilized the individual processes involved in the pilot in the past, the pilot project's configuration of wells and processes is a new combination, and thus Petrobank is subject to unknown operational risks. Other risks associated with the pilot include: the THAI™ technology may prove unsuccessful or commercially unviable; the cost of the pilot may exceed management's estimates, and unknown future regulatory or commodity market factors may make the technology uneconomic.

Intellectual Property Rights

Petrobank's technologies are covered by the registered patents and patent applications described in "*Overview of the Business and Principal Properties - Heavy Oil Business Unit Overview- Intellectual Property*", both concerning the Company's products, the Company's technologies and the territorial protection of the patents. The Company pursues a policy to protect their technologies through applicable patent legislation.

If Petrobank fails to protect its intellectual property rights, competitors may be able to use Petrobank's technology and know-how, and this could weaken the Company's competitive position, reduce revenue and increase costs. The Company relies primarily on a combination of patent, trade secrets, confidentiality procedures and contractual provisions to protect intellectual property in the products and services. These laws and procedures provide only limited protection. Petrobank holds and maintains two granted patents and has one patent pending. However, these patents may not provide sufficiently broad protection, both regarding scope, territorial protection and otherwise, or they may not be enforceable in actions against alleged infringers. As well, despite precautions that are taken, it may be possible for unauthorized third parties to copy or reverse engineer aspects of the current or future products or to independently develop similar or superior technology or design concerning the patents the Company owns.

The competitive nature of Petrobank's heavy oil business and the importance of technology to the competitors' businesses may enhance the likelihood of being subject to third party claims. Any such claims, even if without merit, could be time consuming, result in potentially significant litigation costs or

damages. A claim against Petrobank could require that Petrobank enter into licensing agreements with the owner of the intellectual property on terms that may or may not be acceptable to Petrobank.

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

Political and Regulatory

The oil and gas industry in general is subject to extensive government policies and regulations, which result in additional cost and risk for industry participants. Environmental concerns relating to the oil and gas industry's operating practices are expected to increasingly influence government regulation and consumption patterns which favour cleaner burning fuels such as gas. The Company is uncertain as to the amount of operating and capital expenses that will be required to comply with enhanced environmental regulation in the future.

In addition to the risks faced by Canadian oil and gas companies, Petrobank is conducting exploration and development activities in Colombia, and is dependent on receipt of government approvals or permits or no objection certificates to develop its properties. Based on past performance, Petrobank believes that the government of Colombia supports the exploration and development of its oil and gas properties by foreign companies. Nevertheless, there is no assurance that future political conditions in Colombia will not result in the government adopting different policies respecting foreign development and ownership of oil and natural gas, environmental protection and labour relations. This may affect the Company's ability to undertake exploration and development activities in respect of present and future properties, as well as its ability to raise funds to further such activities. Any delays in receiving government approvals or permits or no objection certificates may delay the Company's operations or may affect the status of the Company's contractual arrangements or its ability to meet its contractual obligations.

International Operations

International operations are subject to political, economic and other uncertainties, including but not limited to, risk of terrorist activities, revolution, border disputes, expropriation, renegotiations or modification of existing contracts, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on

allowable levels of production, currency fluctuations, labour disputes and other uncertainties arising out of foreign government sovereignty over the Company's international operations. The Company's international operations may also be adversely affected by applicable laws and policies of Canada and Colombia.

Exchange Rate Volatility

To the extent revenues and expenditures denominated in or strongly linked to the U.S. dollar are not equivalent, the Company is exposed to exchange rate risk. Revenues in Canada are largely determined by a U.S. dollar reference price. In Colombia, the Company is exposed to the extent U.S. dollar revenues do not equal U.S. dollar expenditures. In addition, a portion of expenditures in Colombia are denominated in pesos, which are difficult to hedge. The Company is not currently using exchange rate derivatives to manage exchange rate risks.

From time to time the Company may enter into hedging agreements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar, however, if the Canadian dollar declines in value compared to the U.S. dollar, the Company will not benefit from the fluctuating exchange rate.

Foreign Currency and Fiscal Matters

The Company's operations and expenditures are to some extent paid in foreign currencies. As a result, the Company is exposed to market risks resulting from fluctuations in foreign currency exchange rates. A material drop in the value of any such foreign currency could result in a material adverse effect on the Company's cash flow and revenues. Currently, there are no significant restrictions on the repatriation of capital and distribution of earnings from Colombia to foreign entities. There can be no assurance, however, that restrictions on repatriation of capital or distributions of earnings from Colombia will not be imposed in the future. Amendments to current taxation laws and regulations which alter tax rates and/or capital allowances could have a material adverse impact on Petrobank. Petrobank also has subsidiaries that operate in different tax jurisdictions.

Permits, Licenses and Leases

Significant parts of the Company's operations require permits, licenses and leases from various governmental authorities and landowners. There can be no assurance that the Company will be able to obtain all necessary permits, licenses and leases that may be required to carry out exploration and development at its projects. If the present permits, licenses and leases are terminated or withdrawn, such event could have an adversely negative effect of the Company's operations.

Title to Properties

Although title reviews are done according to industry standards prior to the purchase of most 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 claim of Petrobank which could result in a reduction of the revenue received by Petrobank.

Potential Liability Regarding Tax Reassessments

The Company has filed tax returns and issued "flow-through shares" whereby certain tax benefits generated from Petrobank's capital expenditure program have been renounced to investors. Should the Company's tax returns or renouncements of capital expenditures be audited in Canada or Colombia, there

exists a risk that the Company could become liable for incremental income taxes and penalties and could be required to indemnify investors as a result of any reduction in benefits received.

Conflicts of Interest

There are potential conflicts of interest to which the directors, officers and principal shareholders of the Company will be subject to in connection with the operations of the Company. Some of the directors, officers and principal shareholders are or may become engaged in other oil and gas interests on their own behalf and on behalf of other companies, and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the ABCA. The directors and officers of the Company may not devote their time on a full-time basis to the affairs of the Company. See “*Interest of Management and Others in Material Transactions*” for further information about recent transactions with related parties. Certain directors of the Board and management of Petrobank own collectively, directly and indirectly, a significant part of the outstanding share capital of the Company, and will therefore have the possibility to influence the decision-making in the Company.

Security

The Company has invested time and resources into developing meaningful, responsible and proactive relationships with local stakeholders and host communities.

Colombia and Peru have a publicized history of security problems associated with certain narco-terrorist groups. The Company and its personnel are subject to these risks. It is difficult to obtain insurance coverage to protect against terrorist incidents and as a result the Company’s insurance program excludes this coverage. Consequently, incidents like this in the future could have a material adverse impact on the Company’s operations.

Please also see the information under the heading “*Risks and Uncertainties*” in the Company’s MD&A for the year ended December 31, 2008, which is incorporated herein by reference. The Company’s MD&A can be located on SEDAR at www.sedar.com.

DIVIDEND RECORD

Petrobank has not declared or paid any dividends on its common shares since its incorporation. Any decision to pay dividends on the common shares will be made by the Board on the basis of Petrobank’s earnings, financial requirements and other conditions existing at such future time. Pursuant to the terms of the agreement with its current banker, the Company cannot declare or pay dividends on its common shares without obtaining the bank’s consent.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Petrobank is authorized to issue an unlimited number of common shares and an unlimited number of Preferred Shares, issuable in series. As at December 31, 2008, there were 83,525,394 common shares and no Preferred Shares issued and outstanding. As at the date of this Annual Information Form, there were 83,528,644 common shares and no Preferred Shares issued and outstanding.

The holders of common shares are entitled to receive notice of and to attend any meeting of the shareholders of Petrobank and are entitled to one vote for each common share held (except meetings at

which only the holders of another class of shares are entitled to vote). The holders of common shares are entitled to receive dividends, on a pro rata basis, if, as and when declared by the Board and, subject to prior satisfaction of all preferential rights, to participate rateably in the net assets of Petrobank in the event of any liquidation, dissolution or winding up of Petrobank, whether voluntary or involuntary, or other distribution of assets of Petrobank among shareholders for the purpose of winding up its affairs.

Preferred Shares

The Preferred Shares may be issued in one or more series and the Board may, by resolution, fix the number of shares in each series and determine the designation, rights, privileges, restrictions and conditions to be attached to shares of each series. The holders of the Preferred Shares are entitled to vote at meetings, to dividends as and when declared by the Board, and, upon liquidation, to receive, out of the net assets of Petrobank, payment in full of the respective amounts which each holder of Preferred Shares paid on the Preferred Shares in preference and priority to any payment on common shares, but such holders shall not be entitled to any further participation in such assets. Preferred Shares series A through C have been previously authorized but currently there are no Preferred Shares outstanding.

Convertible Notes

On May 4, 2007, Petrobank raised US\$250 million through the private placement of 3% convertible notes (the “Notes”) due 2012. The Notes have an annual coupon of 3% and are convertible into common shares of the Company at a conversion price of US\$28.4902, representing a conversion premium of 40% to the volume weighted average share price on April 20, 2007. The conversion price is subject to reduction in certain circumstances such as a special distribution to shareholders or upon a change of control of the Company. Petrobank has the option to call the Notes after three years from the date of issue, should the price of Petrobank’s common shares exceed 120% of the prevailing conversion price of the Notes over a specified time period. If conversion of the Notes is forced, or if the Company’s share price is in excess of the prevailing conversion price upon maturity in May 2012, the Notes will be converted into equity. Alternatively, if the share price is below the prevailing conversion price at maturity, the Company can elect to redeem the principal amount of the Notes in common shares or finance any remaining principal with new debt, equity and / or accumulated cash flows.

NORMAL COURSE ISSUER BIDS

As at December 31 2008, the Company repurchased and cancelled a total of 298,400 Petrobank common shares at an average cost of \$41.11 per share pursuant to Petrobank’s normal course issuer bid (“NCIB”) approved by the TSX. Under the NCIB, the Company can purchase up to 157,107 common shares daily until August 17, 2009 to a maximum of 6,444,777 common shares, except for the period November 3, 2008 to March 31, 2009, where the Company may purchase up to 314,214 common shares daily pursuant to a temporary policy adopted by the TSX. Any common shares Petrobank purchases under the NCIB will be purchased on the open market through the facilities of the TSX at the prevailing market price at the time of the transaction. Common shares acquired under the NCIB are cancelled.

As at December 31 2008, Petrominerales repurchased and cancelled a total of 1,326,000 common shares at an average cost of \$9.89 per share pursuant Petrominerales’ normal course issuer bid approved by the TSX. Under Petrominerales’ normal course issuer bid, Petrominerales can purchase up to 24,977 common shares daily until August 17, 2009 to a maximum of 5,032,719 common shares, except for the period November 3, 2008 to March 31, 2009, where Petrominerales may purchase up to 49,954 common shares daily pursuant to a temporary policy adopted by the TSX. For every common share purchased on the open market one common share is also purchased from Petro International Ltd. (a wholly-owned subsidiary of Petrobank, Petrominerales’ 76.5% shareholder). Accordingly, Petrobank’s indirect

ownership interest in Petrominerales is increasing as it is participating for less than its prorated ownership interest. Common shares acquired under the NCIB are cancelled by Petrominerales.

MARKET FOR SECURITIES

The Company's outstanding common shares are listed and posted for trading on the TSX under the trading symbol "PBG".

On February 6, 2006, the Company's common shares commenced trading on Oslo Børs under the trading symbol "PBG", however, given the low trading volumes of the Corporation's common shares on the Oslo Børs, and to reduce compliance costs and administrative resources associated with maintaining a secondary listing, at the annual and special meeting of shareholders held on May 14, 2008 Petrobank sought and received shareholder approval to de-list Petrobank's common shares from the Oslo Børs. Effective July 10, 2008, Petrobank's common shares were de-listed from the Oslo Børs, however, Petrobank's common shares continue to trade on TSX.

The following table sets forth the monthly price range and volume for Petrobank's common shares on the TSX for the period from January 1, 2008 to December 31, 2008.

Month	High	Low	Volume
January	\$60.39	\$37.00	18,447,492
February	\$63.03	\$50.50	11,613,299
March	\$58.90	\$45.03	16,564,442
April	\$54.58	\$45.13	12,223,883
May	\$61.72	\$47.10	12,525,058
June	\$57.45	\$47.33	12,092,855
July	\$53.14	\$39.00	14,162,445
August	\$47.01	\$33.39	10,548,465
September	\$47.20	\$33.25	14,222,277
October	\$42.40	\$17.50	25,268,634
November	\$26.10	\$16.26	16,519,129
December	\$24.99	\$18.28	12,966,864

DIRECTORS AND OFFICERS

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Petrobank, as of the date of this Annual Information Form, are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Chris J. Bloomer Alberta, Canada	Senior Vice President and Chief Operating Officer, Heavy Oil, and Director	Mr. Bloomer has been the Senior Vice President and Chief Operating Officer, Heavy Oil and Director of Petrobank since May 2007. Prior thereto Mr. Bloomer was Vice President Heavy Oil and Chief Financial Officer of Petrobank.
Ian S. Brown ⁽¹⁾ Alberta, Canada	Director	Mr. Brown is a Chartered Accountant with over 20 years experience in the capital markets. Mr. Brown was a Senior Managing Director at Raymond James Ltd. (and predecessor companies) from 1995 to 2005 and previously was Executive Vice President at the Alberta Stock Exchange. Mr. Brown has been a director of the Company since March 18, 2005.
Louis L. Frank New Hampshire, USA	Director	Mr. Frank has been a director of the Company since September 1993. Since 1992, Mr. Frank has been an independent consultant and President of Recco Inc., an oil and gas development and real estate development company.
Andrew D. Grasby Alberta, Canada	Corporate Secretary	Mr. Grasby has been the Corporate Secretary of the Company since March 2005 and is a Partner at McCarthy Tétrault LLP, a national law firm.
Andrea Hatzinikolas Alberta, Canada	Assistant Corporate Secretary and General Counsel	Ms. Hatzinikolas has been the Assistant Corporate Secretary and General Counsel of Petrobank since August 2008. From February 2007 to August 2008 she was General Counsel of the Company. From 2003 to 2007, Ms. Hatzinikolas was an associate at a national law firm.
Peter Hawkes Alberta, Canada	Vice President Exploration, Canadian Business Unit	Mr. Hawkes was appointed Vice President Exploration Canadian Business Unit, in November 2008. Mr. Hawkes joined Petrobank in November 2005 as Senior Geologist and was promoted to Exploration Manager in July 2007. From May 2004 to July 2005 Mr. Hawkes was a Senior Geologist at Southpoint Resources Ltd. Prior thereto Mr. Hawkes was a Senior Geologist Hunt Oil Company from November 2000 to April 2004.
Allen Knight Alberta, Canada	Vice President, New Ventures	Mr. Knight joined Petrobank in November, 2008 as the Vice President of New Ventures. Prior to joining Petrobank, Mr. Knight was President of Golden Eagle Energy Inc. (a private oil and gas company) from September 2005 to January 2008 and Teal Energy Inc. (a private company) from September 1998 to September 2005.
M. Neil McCrank Alberta, Canada	Director	Mr. McCrank was appointed to the Board of Directors of Petrobank in November, 2008. In June 2008, M. McCrank was appointed as Counsel to Borden Ladner Gervais LLP. From 1998 to 2007, Mr. McCrank was the Chairman of the Alberta Energy and Utilities Board.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Kenneth R. McKinnon ^{(1) (3)} Alberta, Canada	Director	Mr. McKinnon has been a director of the Company since March 2000. Mr. McKinnon holds the position of Vice President Legal and General Counsel of Critical Mass Inc., a website design company.
Jerald L. Oaks ⁽²⁾ Colorado, USA	Director	Mr. Oaks has been a Director of Petrobank since September 1993. He is a Professional Engineer and President of Oaks Resources Management Inc. since June 1986.
Richard Press Alberta, Canada	Vice President Land and Contracts	Mr. Press joined Petrobank in May 2003 as Senior Landman and was promoted to Land Manager in July 2004 and to Vice President Land and Contracts in January 2005. Prior thereto he was a Senior Landman with Talisman Energy Inc. from June 2001 to May 2003.
Corey C. Ruttan Alberta, Canada	Senior Vice President and Chief Financial Officer	Since November 2008, Senior Vice President Finance and Chief Financial Officer. Vice President Finance and Chief Financial Officer of Petrobank from May 2007 to November 2008; Vice President Finance of Petrobank from May 2006 to May 2007; Vice President, Finance and Chief Financial Officer of Petrominerales since May 2006; Director of Corporate Finance and Investor Relations of Petrobank from July 2003 to May 2006.
Doreen M. Scheidt Alberta, Canada	Corporate Controller	Ms. Scheidt has been Corporate Controller of Petrobank since December 2001.
R. Gregg Smith Alberta, Canada	Senior Vice President and Chief Operating Officer, Canada	Mr. Smith was appointed Senior Vice President and Chief Operating Officer, Canada in November, 2008. Mr. Smith was the Vice President, Canada of the Company from March of 2003 to November 2008.
James D. Tocher ^{(2) (3)} Alberta, Canada	Chairman of the Board	Mr. Tocher has been Chairman of the Board since September 1993; and was the Chief Executive Officer of Petrobank from September 1993 to March 2000.
Dr. Harrie Vredenburg ⁽¹⁾⁽³⁾ Alberta, Canada	Director	Professor of Strategic Management and Suncor Energy Chair in Competitive Strategy and Sustainable Development at the Haskayne School of Business at the University of Calgary. Dr. Vredenburg has been a director of the Company since May 2, 2006.
John D. Wright ⁽²⁾ Alberta, Canada	President and Chief Executive Officer and Director	Mr. Wright has been President and Chief Executive Officer and a Director of the Company since March 2000. Mr. Wright is also the President and Chief Executive Officer of Petrominerales Ltd.

Notes:

1. Member of the Audit Committee.
2. Member of the Reserves Committee.
3. Member of the Compensation Committee.
4. The term of office of each director expires at the next annual meeting of shareholders.

As at the date of this Annual Information Form, the directors and senior officers of Petrobank, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 7,279,444 common shares constituting approximately 8.72% of the issued and outstanding common shares.

As at the date of this Annual Information Form, the directors and senior officers of Petrobank, as a group, beneficially owned directly or indirectly, or exercised control or direction over 657,300 common shares of

Petrominerales, an indirect 76.5% owned subsidiary of Petrobank, consisting of approximately 0.66% of the issued and outstanding shares of Petrominerales.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Except as disclosed herein, to the knowledge of the Company no director or officer of the Company and no securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company, or a personal holding company of any such persons, is or has been within the 10 years preceding the date of this Annual Information Form, a director or executive officer of any company, that while that person was acting in such a capacity, or 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.

Rene LaPrade

On April 30, 2008, a management cease trade order (“MCTO”) was issued by the ASC in respect of Sahara Energy Ltd. (“Sahara”), a reporting issuer listed on the TSX Venture Exchange. The MCTO was issued against Sahara for failure to file annual audited financial statements for the year ended December 31, 2007 (the “Unfiled Statements”). The MCTO prohibited certain directors and officers of Sahara, including Mr. Rene LaPrade (a director of Sahara), from trading in securities of Sahara until two business days following the filing of the Unfiled Statements with the ASC or until the MCTO was revoked. The MCTO expired on June 17, 2008.

On January 8, 2009, Mr. Rene LaPrade entered into a settlement agreement with the ASC in respect of an insider trading violation relating to a February 6, 2008 trade. Mr. LaPrade cooperated fully with the ASC in resolving the matter. Mr. LaPrade paid \$10,000 in settlement of the allegations against him and costs of the investigation in the amount of \$500. As part of the settlement agreement, until January 8, 2010, Mr. LaPrade has agreed to cease trading in securities (subject to certain exceptions) and to refrain from acting as a director of any issuer.

Corey C. Ruttan

Mr. Corey C. Ruttan entered into a settlement agreement with the Alberta Securities Commission (“ASC”) on May 3, 2002 in respect of an insider trading violation relating to a May 17, 2000 trade. Mr. Ruttan cooperated completely in resolving the matter with the regulators. The settlement resulted in Mr. Ruttan paying an administrative penalty of \$10,000, representing a return of profits, and the costs of the proceeding in the amount of \$3,925. For a period of one year, Mr. Ruttan agreed to cease trading in securities and to not act as a director or officer of a public company. These restrictions expired on May 3, 2003. Mr. Ruttan is a Chartered Accountant in good standing.

John D. Wright and Chris J. Bloomer

Mr. John D. Wright and Mr. Chris J. Bloomer are directors of Talon International Energy Ltd. (“Talon”), a reporting issuer listed on the TSX Venture Exchange. A cease trade order (the “Order”) was issued on May 7, 2008 against Talon by the ASC for the delayed filing of Talon’s audited annual financial statements and management’s discussion and analysis for the year ended December 31, 2007 (“Annual Filings”). The Annual Filings were filed by Talon on SEDAR on May 8, 2008.

As a result of the Order, the TSX Venture Exchange suspended trading in Talon’s shares on May 7, 2008. Talon made application to the ASC for a revocation of the Order and in conjunction with Talon’s

application for revocation of the Order, the ASC reviewed Talon's financial statements and management's discussion and analysis for the periods ending March 31, 2008, June 30, 2008 and the year ended December 31, 2007 (collectively, the "Reviewed Financial Statements"), and provided Talon with comments in respect of such Reviewed Financial Statements. Talon is currently working to revise the Reviewed Financial Statements to address the comments of the ASC and intends to re-file the Reviewed Financial Statements on SEDAR. The Order is still in effect as at the date of this Annual Information Form.

CONFLICTS OF INTEREST

Certain officers and directors of Petrobank are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of Petrobank. In addition, the ABCA, Petrobank's governing statute, requires that any director or officer of a corporation who is party to, or is a director and officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company must disclose his or her interest and, in the case of directors, refrain from voting on any matter in respect of such contract, unless otherwise permitted under the ABCA.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

In July 2003, the Company acquired the THAI™ and CAPRI™ patented heavy oil recovery technologies indirectly from one director of the Company (John D. Wright) and one former director of the Company and a third party, pursuant to an agreement made by an independent committee of the Board. The former director recovered his \$226,000 investment and Mr. Wright received cash of \$189,000 on his \$226,000 investment and retained a 7.5 percent net profits interest in any future third party (non-Petrobank) licensing royalties generated from the technologies.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar for the common shares listed on the TSX is Computershare Trust Company of Canada, located at 600, 530 - 8th Avenue SW, Calgary, Alberta T2P 3S8.

MATERIAL CONTRACTS

Except as disclosed below, the Company has not entered into any material contracts that are not disclosed or otherwise entered in the ordinary course of business.

On May 2, 2007 Petrobank and Norsk Tillitsmann ASA, as Loan Trustee on behalf of the convertible noteholders, entered into a loan agreement (the "Loan Agreement") with respect to the private placement of 3.00% convertible notes due May 2012. See "*Description of Capital Structure – Convertible Notes*". The Loan Agreement may be found on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

Deloitte & Touche LLP, Chartered Accountants, are the Company's auditors and as such have prepared an opinion with respect to the Company's consolidated financial statements as at and for the fiscal year ended December 31, 2008. Deloitte & Touche LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Information relating to reserves in this Annual Information Form was calculated by McDaniel, Sproule and D&M as independent qualified reserves evaluators. The principals of McDaniel, Sproule and D&M, individually or as a group, neither own nor expect to receive any of Petrobank's securities, directly or indirectly.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, will be available in the Management Proxy Circular of the Company provided for the annual meeting of the shareholders of the Company to be held on May 12, 2009, to be available at www.sedar.com or at www.petrobank.com. Additional financial information is also provided in the Company's consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2008 which are contained in the Annual Report of the Company for the year ended December 31, 2008, available at www.sedar.com or at www.petrobank.com.

APPENDIX A

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Petrobank Energy and Resources Ltd. (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.

Independent qualified reserves evaluators have evaluated the Company’s reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

- (a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluators;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation, to inquire whether there had been any disputes between the previous independent qualified reserves evaluator, and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

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:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F1 which is the report of the independent qualified reserves evaluators on the reserves data, and
- (c) 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, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) “**Chris J. Bloomer**”
Chris J. Bloomer
Senior Vice President Heavy Oil

(signed) “**R. Gregg Smith**”
R. Gregg Smith
Senior Vice President, Canadian Business Unit

(signed) “**James D. Tocher**”
James D. Tocher
Chairman of the Board and Member
of the Reserves Committee

(signed) “**John D. Wright**”
John D. Wright
President and Chief Executive Officer,
Director and Member of the Reserves Committee

APPENDIX B

FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Petrobank Energy and Resources Ltd. (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 attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company’s management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County)	Net Present Value of Future Net Revenue (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Petrobank Energy and Resources Ltd., As of December 31, 2008, prepared December 2008 to February 2009	Canada				
Total			Nil	1,489,900	Nil	1,489,900

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 11, 2009

(signed) "**Douglas R. Bates**"

Douglas R. Bates, P. Eng.
Associate

(signed) "**Khani Ghaffari**"

Khani Ghaffari, P. Eng.
Associate

(signed) "**Lucia M. Recul**"

Lucia M. Recul, P. Eng.
Associate

(signed) "**Michael W. Maughan**"

Michael W. Maughan, C.P.G., P. Geol.
Vice-President, Geoscience

(signed) "**Robert N. Johnson**"

Robert N. Johnson, P. Eng.
Vice-President, Engineering

APPENDIX C

FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Petrobank Energy and Resources Ltd. (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, audited and reviewed and reported on to the Company’s management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue \$M (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
February 24, 2009	Canada	-	294,000	-	294,000

5. In our opinion, the reserves data 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 report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed) "*P.A. Welch*"

P.A Welch, P. Eng.

Calgary, Alberta

Date: February 24, 2009

APPENDIX D

FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Petrominerales Colombia Ltd. (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 assure that reserves estimates 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 Canadian income taxes) in thousands of United States dollars (M U.S.\$) for 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 as of December 31, 2008, and identifies the respective portions thereof that we have evaluated and reported to Company’s management:

Independent Qualified Reserves Evaluator	Description and Effective Date of Evaluation	Location of Reserves	Net Present Value of Future Net Revenue (before Canadian Income Tax, Discounted at 10 Percent)			
			Audited (M U.S.\$)	Evaluated (M U.S.\$)	Reviewed (M U.S.\$)	Total (M U.S.\$)
DeGolyer and MacNaughton	Appraisal Report as of December 31, 2008 on Certain Properties in Colombia for Petrominerales Colombia Ltd. dated February 27, 2009	Colombia	Not Applicable	933,286	Not Applicable	933,286

5. In our opinion, the reserves and revenue evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the report preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

DeGolyer and MacNaughton, Dallas, Texas, USA, dated February 27, 2009.

Submitted,

(signed) "*DeGolyer and MacNaughton*"

DeGolyer and MacNaughton

APPENDIX E

FORM 52-110F1

AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF

1. **The Audit Committee's Charter**

See Appendix “F” attached to this Annual Information Form for the text of Petrobank’s Audit Committee charter.

2. **Composition of the Audit Committee**

Ian S. Brown – independent and financially literate.

Kenneth R. McKinnon – independent and financially literate.

Harrie Vredenburg – independent and financially literate.

3. **Relevant Education and Experience**

Ian S. Brown: Mr. Brown has been a member of the Institute of Chartered Accountants since 1983. Mr. Brown was a Senior Managing Director at Raymond James Ltd. (formerly Goepel McDermid Inc.) from 1995 until December 2005, and was Executive Vice President at the Alberta Stock Exchange from 1986 to 1995. Mr. Brown is also Director of Bonavista Energy Trust, the Canadian Investor Protection Fund and Stem Cell Therapeutics Corp. Mr. Brown obtained his Bachelor of Arts from McMaster University in 1979 and his Bachelor of Commerce (Accounting) from the University of Windsor in 1980. Mr. Brown is a Chartered Accountant with over 25 years experience in the financial markets. He has gained significant experience and expertise in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting. He has gained an understanding of Audit Committee functions through his Board and committee experience with other public corporations.

Kenneth R. McKinnon: Mr. McKinnon obtained his Bachelor of Commerce from the University of Calgary (Accounting) in 1980 and obtained his Bachelor of Laws from Queens University in 1983. Mr. McKinnon was Vice President, Finance and Chief Financial Officer of the Company from November 1997 to March 2000. Mr. McKinnon is also a director of Quorum Information Technologies Inc. Over this time he gained experience in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting and has experience supervising persons engaged in the preparation, analysis and evaluation of financial statements. He has gained an understanding of Audit Committee functions through his involvement with the Company and other public corporations. In 2006, he earned the ICD.D designation of the Institute of Corporate Directors, as a certified corporate director.

Dr. Harrie Vredenburg is Professor of Strategic Management and Suncor Energy Chair in Competitive Strategy and Sustainable Development at the University of Calgary’s Haskayne School of Business and is the founding director of the International Institute for Resource Industries and Sustainability Studies (IRIS), established in 1994. Before joining the Haskayne School of Business at U of C, Dr. Vredenburg was a professor at McGill University’s Desautels Management School. Dr. Vredenburg’s research, focused on competitive strategy, innovation and sustainable development in global energy and natural resource industries, has been published

in the leading international management journals. Prior to his academic career he was a marketing manager with American Express in Toronto and New York. For more than 25 years he has worked as a consultant to both corporations and governments. Dr. Vredenburg earned a PhD in strategic management from the Richard Ivey School of Business at the University of Western Ontario in 1986 and holds MBA and BA degrees from the University of Toronto and McMaster University. In 2005 he earned the ICD.D designation of the Institute of Corporate Directors, as a certified corporate director. He was certified as a mediator by the Consensus Building Institute (Harvard-MIT Public Disputes Program) in 1997.

4. **Reliance on Certain Exemptions**

N/A

5. **Reliance on the Exemption in Subsection 3.3(2) or Section 3.6**

N/A

6. **Reliance on Section 3.8**

N/A

7. **Audit Committee Oversight**

N/A

8. **Pre-Approval Policies and Procedures**

The Audit Committee requires the Company to obtain Audit Committee approval for any non-audit services exceeding immaterial amounts.

9. **External Auditor Service Fees (By Category)**

<u>Year Ended</u>	<u>Audit Fees⁽¹⁾</u>	<u>Audit Related Fees⁽²⁾</u>	<u>Tax Fees⁽³⁾</u>	<u>All Other Fees</u>
2007	\$311,978	\$193,000	\$89,405	Nil
2008	\$421,036	\$169,000	\$98,752	Nil

Notes:

- Audit fees in 2008 and 2007 include the audit of Petrominerales.
- Audit related fees in 2007 relate to quarterly reviews and the issuance of securities for both Petrobank and Petrominerales. In 2008 includes costs related to quarterly reviews and an IFRS scoping analysis for both Petrobank and Petrominerales, and the issuance of Petrobank securities.
- Tax fees relate to preparation of all corporate tax returns, tax research and miscellaneous tax issues for both Petrobank and Petrominerales.

APPENDIX F

Approved and adopted by the Board on May 13, 2004, as amended March 11, 2009

PETROBANK ENERGY AND RESOURCES LTD.

AUDIT COMMITTEE OF THE BOARD OF DIRECTORS MANDATE AND TERMS OF REFERENCE

I. PURPOSE

The primary function of the Audit Committee is to assist the Board of Directors (the "Board of Directors" or "Board") of Petrobank Energy and Resources Ltd. ("Petrobank" or the "Corporation") in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by Petrobank to any regulatory body or the public; the Corporation's systems of internal controls regarding preparation of those financial statements and related disclosures that management and the Board have established; and the Corporation's auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should encourage continuous improvement of, and should foster adherence to, the Corporation's policies, procedures and practices at all levels. The Audit Committee's primary objectives are:

To assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

To provide for open communication between directors and external auditors;

To enhance the external auditor's independence;

To increase the credibility and objectivity of financial reports; and

To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditors.

II. COMPOSITION

1. The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of Petrobank and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110")) unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.
2. All of the members of the Audit Committee shall be "financially literate"(as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.
3. The members of the Audit Committee shall be elected by the Board of Directors at the annual organizational meeting of the Board of Directors and remain as members of the Audit Committee until their successors shall be duly elected and qualified.

4. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

III. MEETINGS

1. The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its mandate to foster open communication, the Audit Committee should meet at least annually with management and the external auditors in separate executive sessions to discuss any matters that the Audit Committee or each of these groups believe should be discussed privately. The Audit Committee or at least its Chair should meet with the external auditors and management quarterly to review the Corporation's financials consistent with Section IV.2 below. The Chief Financial Officer may, at the discretion of the Audit Committee, be present at meetings of the Audit Committee and may be excused from all or part of any such meetings by the Chairman.
2. Minutes of all meetings of the Audit Committee shall be taken and the Audit Committee shall report the results of its meetings and reviews undertaken and any associated recommendations to the Board of Directors.
3. A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

IV. RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Audit Committee shall:

Documents/Reports Review

1. Review and update this Charter, as conditions dictate.
2. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval where required.
3. Review the reports to management prepared by the external auditors and management's responses.
4. Review of significant auditor findings during the year, including the status of previous audit recommendations.
5. Be satisfied with and periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.
6. It is the responsibility of the Audit Committee to review, on behalf of the Board, the Corporation's internal control systems in order satisfy the Audit Committee that the internal control systems are sufficient to reasonably ensure that:
 - controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;

- internal controls over financial reporting are sufficient to meet the requirements under Multilateral Instrument 52-109 of the Canadian Securities Administrators,
- legal, ethical and regulatory requirements are complied with; and
- major issues as to the adequacy of the Corporation's internal controls and any special audit stops adopted in light of material control deficiencies are reviewed with the Audit Committee by the Chief Financial Officer of the Corporation.

External Auditors

7. Be directly responsible for overseeing the work of the external auditors, including the resolution of disagreements between management and the external auditors regarding financial reporting.
8. Recommend to the Board the external auditors to be nominated for appointment by the shareholders.
9. Recommend to the Board the terms of engagement of the external auditor, including their compensation and a confirmation that the external auditors shall report directly to the Audit Committee.
10. On an annual basis, review and discuss with the auditors all significant relationships the auditors have with the Corporation to determine the auditors' independence.
11. Review the performance of the external auditors and approve any proposed discharge of the external auditors when circumstances warrant.
12. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.
13. Periodically consult with the external auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.
14. Consider, in consultation with the external auditor, the audit scope and plan of the external auditor.
15. Pre-approve the completion of any non-audit services by the external auditors and determine which non-audit services the external auditor is prohibited from providing and the Audit Committee may delegate to one or more independent members of the Audit Committee the authority to pre-approve non-audit services, provided that such member(s) reports to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) complies with such other procedures as may be established by the Audit Committee from time to time.

Financial Reporting Processes

16. In consultation with the external auditors and management, review the integrity of the organization's financial reporting processes, both internal and external.
17. Consider judgments concerning the appropriateness of the Corporation's accounting policies.
18. Consider and approve, if appropriate, major changes to the Corporation's auditing and accounting principles and practices as suggested by the external auditors or management.

19. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).
20. Establish a procedure for:
 - the receipt, retention and handling of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
21. Approve management recommendations of appointment of individuals to senior financial reporting positions within the Corporation.

Process Improvement

22. Establish regular and separate systems of reporting to the Audit Committee by management and the external auditors regarding any significant judgments made in management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.
23. Following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.
24. Review with external auditors their assessment of internal controls, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements.

Ethical and Legal Compliance

25. Ensure that management has the proper review system in place to ensure that the Corporation's financial statements, reports and other financial information disseminated to regulatory organizations and the public satisfy legal requirements.
26. On at least an annual basis, review with the Corporation's counsel and/or management, any legal matters, compliance with applicable laws and regulations, or inquiries received from regulators or government agencies that could have a significant impact on the organization's financial statements.
27. Conduct and authorize investigations into any matters within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain, and to set and pay compensation for any independent counsel and other professionals to assist in the conduct of any investigation.
28. Perform any other activities consistent with this Charter, the Corporation's by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.