ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2010

MARCH 9, 2011

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ABBREVIATIONS AND CONVENTIONS

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

Oil and Natural Gas Liquids

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbls/d	barrels of oil or natural gas liquids per day
mbbls/d	one thousand barrels per day

Natural Gas

mcf	one thousand cubic feet
mmcf	one million cubic feet
bcf	one billion cubic feet
Mcf/d	one thousand cubic feet per day
MMcf/d	one million cubic feet per day

Other

BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
WTI	West Texas Intermediate

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Certain other terms used herein but not defined herein are defined in NI 51 101 and/or CSA 51-324, unless the context otherwise requires, shall have the same meanings herein as in NI 51 101 and/or CSA 51-324.

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

To Convert From	To	Multiply By
cubic feet	cubic metres ("m3")	0.028
cubic metres	cubic feet	35.301
bbls	m3	0.159
m3	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.4710

Unless otherwise indicated, references in this Annual Information Form to "dollars" and "$" are to United States dollars.

In all cases where percentage figures are provided, such percentages have generally been rounded to the nearest whole number.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2010.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

Selected Defined Terms

"**ABCA**" means *Business Corporations Act* (Alberta);

"**C&T Cos**" means Parex Barbados and Parex Colombia and, thereby, indirectly Parex Trinidad;

"**C&T Cos Shares**" means the common shares in each of the C&T Cos;

"**Common Shares**" means the common shares in the capital of the Company;

"**Company**" or "**Parex**" means Parex Resources Inc.;

"**Parex Barbados**" means Parex Resources (Barbados) Ltd., a corporation organized under the laws of Barbados;

"**Parex Barbados Shares**" means the common shares in the capital of Parex Barbados;

"**Parex Colombia**" means Parex Resources (Colombia) Ltd., a corporation organized under the laws of Barbados;

"**Parex Colombia Shares**" means the common shares in the capital of Parex Colombia;

"**Parex Trinidad**" means Parex Resources (Trinidad) Ltd., a corporation organized under the laws of Trinidad & Tobago;

"**Parex Warrants**" means Common Share purchase warrants of Parex, each whole warrant entitling the holder thereof to purchase one Common Share at a price of Cdn$3.00 from November 6, 2009 to December 6, 2009;

"**PARI Common Shares**" means the Class A shares in the capital of PARI;

"**Petro Andina**" or "**PARI**" means Petro Andina Resources Inc.;

"**Pluspetrol**" means Pluspetrol Resources Corporation N.V., a corporation existing under the laws of The Netherlands and any successor corporation; and

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

Selected Oil and Gas Terms

"**API**" means the American Petroleum Institute;

"**API gravity**" means the American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

"**CSA 51-324**" means the Staff Notice 51-324 - *Glossary To NI 51-101 Standards of Disclosure For Oil And Gas Activities* of the Canadian Securities Administrators;

"**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;

"**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 certainly;

"**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;

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

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems;

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

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

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

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum engineers of Calgary, Alberta;

"**GLJ Report**" means the report of GLJ dated January 31, 2011 evaluating the oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2010;

"**gross**" means:

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

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

(c) in relation to properties, the total area of properties in which a reporting issuer has an interest;

"**net**" means:

(a) in relation to a reporting issuer's interest in production or reserves, the reporting issuer's working interest (operating or non-operating) share after deduction of royalty obligations, plus the reporting issuer's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating a reporting issuer's working interest in each of its gross wells; and

(c) in relation to our interest in a property, the total area in which a reporting issuer has an interest multiplied by the working interest owned by it;

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

"**possible reserves**" are those additional reserves that are less certain to be recovered than probable resources. There is a 10% probability that the quantities actually received will equal or exceed the sum of proved plus probable plus possible.

"**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;

"**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;

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates; and

"**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.

FORWARD LOOKING STATEMENTS

Certain information regarding Parex set forth in this document, including management of the Company's ("**Management**") assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent Parex' internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although Management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause Parex' actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex.

In particular, forward-looking statements included in this Annual Information Form include, but are not limited to, size of, and future net revenues from, oil and natural gas reserves; statements with respect to the performance characteristics of the Company's oil and natural gas properties; supply and demand for oil and natural gas; treatment under governmental regulatory regimes and tax laws; financial and business prospects and financial outlook; results of operations, production, future costs, reserves and production estimates; drilling plans; activities to be undertaken in various areas including the fulfillment of exploration commitments; timing of drilling, completion and tie in of wells; tax horizon; access to infrastructure; timing of development of undeveloped reserves; and planned capital expenditures, the timing thereof and the method of funding.

Statements relating to "reserves" or "resources" are by their nature 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. The recovery and reserve estimates of Parex' reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward looking statements.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to, the impact of general economic conditions in Canada, Colombia and Trinidad & Tobago; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced, in Canada, Colombia and Trinidad & Tobago; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; partner approval of capital work programs and other matters requiring approval; imprecision in reserve and resource estimates; the production and growth potential of Parex' assets; obtaining required approvals of regulatory authorities, in Canada, Colombia and Trinidad & Tobago; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; volatility in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; the risks discussed under "Risk Factors" and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Parex' operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Although the forward-looking statements contained in this Annual Information Form are based upon assumptions which Management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this Annual Information Form, Parex has made assumptions regarding: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates, future operating costs, and other matters.

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

Management has included the above summary of assumptions and risks related to forward-looking information provided in this Annual Information Form in order to provide shareholders with a more complete perspective on Parex' current and future operations and such information may not be appropriate for other purposes. Parex' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Parex will derive therefrom. These forward-looking statements are made as of the date of this Annual Information Form and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

CORPORATE STRUCTURE

General

Parex was incorporated under the ABCA on August 17, 2009 as "1485196 Alberta Ltd." On September 29, 2009, Parex filed articles of amendment to remove its private company restrictions and change its name to "Parex Resources Inc.".

The Company's registered office is located at 1400, 350-7th Avenue S.W., Calgary, Alberta T2P 3N9 and its head office is located at 1900, 250 - 2nd Street S.W., Calgary, Alberta, Canada T2P 0C1.

The Common Shares of Parex trade on the TSXV under the symbol "PXT".

Intercorporate Relationships

As at the date hereof, the Company has three direct or indirect wholly-owned subsidiaries (each a "**Subsidiary**" and collectively, the "**Subsidiaries**"). Unless the context otherwise requires, references herein to "Parex" or the "Corporation" mean Parex Resources Inc. and its direct and indirect Subsidiaries on a consolidated basis.

The following chart contains the name of each Subsidiary, the jurisdiction of incorporation and laws of incorporation, the registered holder(s) of voting shares of each Subsidiary, the percentage of voting shares held and the business conducted by each Subsidiary:

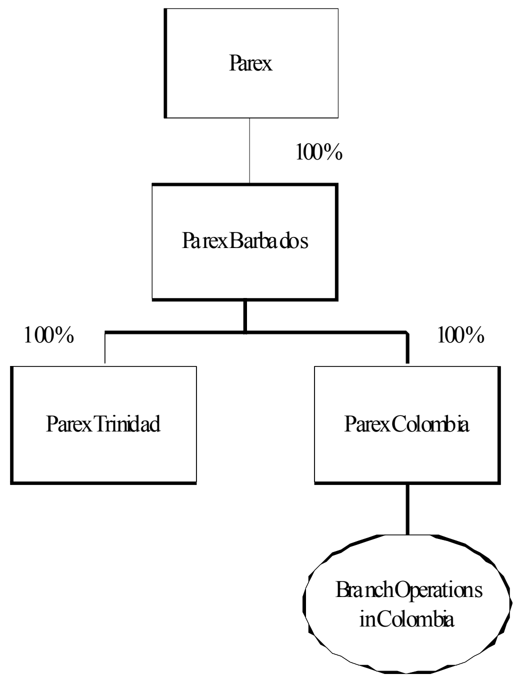
Name of Subsidiary	Jurisdiction of Incorporation and Laws of Incorporation	Registered Holder of Voting Securities and Percentage Held	Business Conducted
Parex Resources (Barbados) Ltd.	Barbados (*Companies Act of Barbados* and licensed under the *International Business Companies Act*)	Parex (100%)	Holding company.
Parex Resources (Colombia) Ltd.	Barbados (*Companies Act of Barbados*)	Parex Barbados (100%)	All of the Company's activities in Colombia are conducted through a Colombian branch of this entity.
Parex Resources (Trinidad) Ltd.	Trinidad & Tobago (Companies Act, 1995)	Parex Barbados (100%)	All of the Company's activities in Trinidad & Tobago are conducted through this entity.

Effective May 31, 2010, Parex reorganized its holdings in Parex Colombia, such that Parex Barbados became the sole holder of all of the issued and outstanding voting shares of Parex Colombia and Parex holds non-voting preferred shares of Parex Colombia. See *Corporate Structure* for further information.

Parex provides certain administrative, management and technical support services to certain of its Subsidiaries pursuant to administrative, management and technical support service agreements. The Company has entered into administrative, management and technical support service agreements with Parex Trinidad and Parex Colombia in order to provide these Subsidiaries with support services from Canada.

Corporate Structure

The following chart illustrates the Company's current organizational structure:



Note:

(1) Parex Barbados is the sole holder of all of the issued and outstanding voting shares of Parex Colombia and Parex holds all of the non-voting preferred shares of Parex Colombia.

GENERAL DEVELOPMENT OF THE BUSINESS

History of the Company

Parex was originally incorporated on August 17, 2009 for the purpose of completing the Arrangement (as defined below) and prior to completion of the Arrangement did not carry on any active business other than in connection with the Arrangement and related matters.

In connection with a statutory arrangement (the "**Arrangement**") pursuant to Section 193 of the ABCA involving PARI, Pluspetrol and certain other parties, Pluspetrol, through a series of transactions, acquired all of the outstanding PARI Common Shares. Under the Arrangement, a holder of PARI Common Shares received, for each PARI Common Share, Cdn$7.65 in cash, one Common Share of Parex and one-tenth of a Parex Warrant. Each whole Parex Warrant entitled the holder thereof to purchase one Common Share at a price of Cdn$3.00 for a period of 30 days from the effective date of the Arrangement, which occurred on November 6, 2009.

Pursuant to the Arrangement, Parex acquired PARI's assets located in Colombia and Trinidad & Tobago through the acquisition of all of the issued and outstanding C&T Cos Shares. The C&T Cos were indirect wholly owned subsidiaries of PARI formed for the purpose of engaging in the business of acquiring properties and exploring for, developing and producing crude oil and natural gas in Trinidad & Tobago and Colombia. Parex Barbados holds all of the issued and outstanding common shares of Parex Trinidad and Parex Colombia.

On September 29, 2009, Parex closed a bought deal private placement (the "**Parex Private Placement**") whereby Parex issued 6,670,000 subscription receipts (the "**Subscription Receipts**") at a price of Cdn$3.00 per Subscription Receipt for gross aggregate proceeds of approximately Cdn$20 million. The proceeds of the Parex Private Placement were held in escrow pending the satisfaction of certain conditions, including receipt of all necessary court, regulatory, securityholder and stock exchange approvals for the Arrangement, the completion of the Parex Management Private Placement (as defined below) and certain steps of the Arrangement. Upon these conditions being met and as part of the Arrangement, the net proceeds of the Parex Private Placement were released to Parex and each Subscription Receipt was converted into one Common Share without additional payment.

As part of the Arrangement, Parex completed a private placement of 3,333,333 Common Shares at a subscription price of Cdn$3.00 per share for gross proceeds of up to Cdn$10 million to directors, officers and employees of the Company (the "**Parex Management Private Placement**").

Upon completion of the Arrangement, Parex became a reporting issuer in each of the Provinces of Canada and the Common Shares and the Parex Warrants commenced trading on the TSXV on November 12, 2009, under the symbols "PXT" and "PXT.WT", respectively. The Parex Warrants were subsequently delisted upon their expiry on December 6, 2009.

For a description of the Company's exploration, development and production activities in 2009 and 2010, see *Description of the Business and Operations* and *Principal Properties* in this Annual Information Form.

On November 16, 2010, Parex completed a bought deal equity financing pursuant to which the Company issued an aggregate of 13,000,000 Common Shares at $5.80 per Common Share for aggregate gross proceeds of $75,400,000.

Significant Acquisitions

Parex did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 *Continuous Disclosure Obligations*. See *General Development of the Business - History of the Company*.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

The Company, through Parex Colombia and Parex Trinidad, is engaged in oil and natural gas exploration, development and production in South America and the Caribbean region.

Parex Resources (Barbados) Ltd.

Parex Barbados was incorporated on January 24, 2008 under the Companies Act of Barbados. Parex Barbados does not carry on any business and was incorporated for the purpose of incorporating a subsidiary under the laws of Trinidad & Tobago, being Parex Trinidad, and subsequently, to hold 100% of the voting shares equity of Parex Trinidad and to also hold 100 percent of the voting shares equity of Parex Colombia. Parex Barbados also facilitates future capitalization of its subsidiaries.

Parex Resources (Trinidad) Ltd.

Parex Trinidad was incorporated on February 6, 2008 under the *Companies Act*, 1995 of Trinidad & Tobago for the purposes of carrying on oil and natural gas exploration and development activities in Trinidad & Tobago.

On December 12, 2007 PARI entered into a joint venture agreement (the "**JVA**") with Voyager Energy Ltd. ("**VEL**" or "**Voyager**"), now a wholly owned subsidiary of Niko Resources Ltd. relating to participation in the production sharing contracts ("**PSCs**") with the Republic of Trinidad & Tobago for the central range deep blocks (the "**Central Range Deep Blocks**") and central range shallow horizon blocks (the "**Central Range Shallow Blocks**" and collectively with the Central Range Deep Blocks, the "**Central Range Blocks**"). Under the terms of the JVA, should VEL be awarded the PSCs, VEL would take the steps necessary to effect the assignment of an interest in the PSCs to PARI or a subsidiary of PARI. During the obligatory exploration phase Parex Trinidad would be a 50% partner and would be the operator of both blocks. Subsequently the JVA was transferred to Parex Trinidad. Under the JVA, upon assignment of the PSCs, Parex Trinidad would be obligated to carry VEL's first $5 million of seismic obligation as well as to provide the necessary guarantees to Trinidad & Tobago pursuant to the JVA, of the minimum work obligations under the PSCs. On September 18, 2008 VEL, through its wholly owned subsidiary

Voyager Energy (Trinidad) Ltd. ("**VETL**") was granted the PSCs. On March 17, 2009 the Ministry of Energy and Energy Industries ("**MEEI**") of Trinidad & Tobago consented to the assignment by VETL of a 50% interest in the PSCs to Parex Trinidad.

Exploration activity commenced with the granting of the Central Range Blocks on September 18, 2008. Work activity on the Central Range Blocks by Parex Trinidad subsequent to completion of the Arrangement, has included:

- Commencement of an environmental base line study;
- A 5,500 linear kilometre airborne geophysical survey; and
- A 216 kilometre two-dimensional ("**2D**") seismic acquisition program.

The Company has purchased a performance bond and provided a guarantee to the underwriters of the bond in the amount of $33 million to cover its and VETL's share of the financial guarantees required under the PSCs for the original initial 48-month exploration phase on the Central Range Blocks. In the event of default by VETL, the JVA provides that VETL's working interest shall vest in Parex Trinidad. The obligations under the PSCs are to perform the exploration work commitments on the Central Range Blocks, irrespective of actual cost. Parex has no liability to spend the actual amount guaranteed. The guarantee amount has not been reduced to reflect the 2D seismic commitment work performed in 2009 and 2010.

On September 16, 2009, Parex Trinidad entered into an agreement with Primera Oil and Gas Limited and Primera Energy Resources Ltd. (together, "**Primera**") (the "**Farm In**") to farm in to the interests of these companies in the Moruga Block Exploration and Production Licence located in South Central Trinidad (the "**Moruga Block**"). The terms of the Farm In require Parex Trinidad to drill two exploration wells on the Moruga Block with one well achieving a minimum depth of 10,500 feet and the other to be drilled to a minimum depth of 8,600 feet or to the top of the cretaceous section. In connection with the Farm In, an application has been made for Parex Trinidad to become the operator of the Moruga Block. The Farm In and transfer of operatorship are subject to approval by the MEEI and the Ministry of Finance of the Republic of Trinidad & Tobago.

Parex Trinidad will earn a 50 percent working interest in the Moruga Block by paying 95% of all costs, to a maximum of $13.3 million for drilling and evaluating these two exploration wells. The Moruga Block encompasses 11,970 gross acres and targets oil prone prospects. The earning requirements for the Moruga Block have yet to be completed. The Company drilled two wells on the Moruga Block in 2010. The Company is evaluating follow-up appraisal locations to the Snowcap-1 discovery. At the completion of testing the Snowcap-1 well will be suspended until a development plan is concluded and approved.

Current activity is focused on interpretation of seismic data and prospect generation.

The drilling of two shallow exploration wells on the Central Range Block has been approved and is expected to commence in 2011.

See *Principal Properties*.

Parex Resources (Colombia) Ltd.

Parex Colombia was incorporated on January 8, 2009 under the *Companies Act* of Barbados for the purpose of carrying on oil and natural gas exploration and development activity in Colombia. Parex Colombia's activities in Colombia are performed through a branch known as Parex Resources Colombia Ltd. Sucursal ("**PACLS**"). A certificate of existence and legal representation was issued by the Camara de Comercio de Bogota on February 26, 2009 whereby Parex Colombia was able to commence activity in Colombia.

PARI participated in the Colombia Mini Bid Round 2008. Bids were made jointly with Columbus Energy Sucursal Colombia ("**CESC**") under the terms of a Joint Bid and Study agreement. On December 4, 2008 PARI and CESC were jointly the successful bidders for four exploration blocks in the Llanos Basin – Block LLA-16 ("**Block**

LLA-16"), Block LLA-20 ("**Block LLA-20**"), Block LLA-29 ("**Block LLA-29**") and Block LLA-30 ("**Block LLA-30**" and collectively with Block LLA-16, Block LLA-20 and Block LLA-29, the "**Blocks**").

On January 30, 2009 PARI and CESC signed joint venture agreements ("**Acuerdo Union Temporal**") for each of the Blocks with each partner having a 50% interest. Subsequently, on March 11, 2009, PARI and CESC amended the Acuerdo Union Temporal for each of the Blocks to reflect Parex Colombia as the operating entity in Colombia instead of PARI.

On April 20, 2009 Exploration and Production Contracts for the Blocks were finalized between the Agencia Nacional de Hidrocarburos ("**ANH**"), and Parex Colombia and CESC. Pursuant to the contracts, Parex Colombia and CESC each have provided guarantees to ANH in the form of letters of credit in respect of a portion of the work commitments for Blocks LLA-16 and LLA-20 on July 14, 2009. Guarantees to the ANH for Blocks LLA-29 and Block LLA-30 were provided on November 5, 2009.

On July 21, 2010 the Company was advised by the ANH that it had been deemed to be the successful bidder for Block LLA-57 in the Llanos Basin. On February 11, 2011, Parex Colombia, through PACLS, finalized the Exploration and Production Contract for Block LLA-57. Block LLA-57 covers 104,532 gross acres and is located north and adjacent to Block LLA-20 Parex Colombia has a 100% interest in LLA-57

See *Principal Properties*.

Competitive Conditions and Renegotiation or Termination of Contracts

There is considerable competition in the worldwide oil and natural gas industry, including in Trinidad & Tobago, Colombia and Canada where the Company's assets and activities are located. Operators more established than the Company, with access to broader technical skills, larger amounts of capital and other resources, are active in the industry in all three countries in which the Company has operations. This represents a significant risk for the Company, which must rely on modest resources and access to capital markets for funding of its activities. See *Risk Factors*.

Risks of Foreign Operations

All of the Company's oil and natural gas operations occur outside of Canada and therefore are subject to political and regulatory risk in those other jurisdictions. See *Risk Factors*.

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Company or any of its subsidiaries, or any voluntary receivership, bankruptcy or similar proceeding by the Company or any of its subsidiaries, within the three most recently completed financial years or during or proposed for the current financial year.

Reorganizations

Other than the Arrangement and the exchange by Parex of its common shares for preferred shares in Parex Colombia and the issuance by Parex Colombia of common shares to Parex Barbados, there have been no material reorganizations of the Company or any of its subsidiaries within the three most recently completed financial years or during or proposed for the current financial year.

Employees

As at December 31, 2010, Parex employed 28 full time employees located in the Calgary head office. Parex Trinidad employed 9 full-time employees. PACLS employed 31 full-time employees. Parex intends to add additional professional, administrative and field staff as the need arises.

PRINCIPAL PROPERTIES

A description of Parex Trinidad and Parex Colombia properties is provided below.

Colombia

Parex Colombia, and its partner CESC, acquired blocks LLA-16, LLA-20, LLA-29 and LLA-30 in the prospective Llanos basin. The exploration and production contracts in respect of the Blocks were signed with the ANH on April 20, 2009. The Blocks cover an area of approximately 489,000 acres and Parex Colombia has a 50% working interest and is the operator of record. On February 11, 2011 Parex Colombia, through PACLS, finalized the Exploration and Production contract for Block LLA-57. Block LLA-57covers 104,532 acres and lies immediately north of Block LLA-20. The Company's bid terms for Block LLA-57, in which it will have a 100 percent working interest, were a Phase 1 work program of US$10.1 million and a supplemental royalty of one percent over the base ANH royalty. After signing the contract Parex is required to place a guarantee of approximately US$3.85 million with the ANH.

The exploration and production contracts consist of an initial exploration phase of 36 months. Subsequent to this period, the Company has the option to enter into two consecutive exploration phases of 18 months each, subject to certain criteria required by the ANH. Parex Colombia's net commitment for the initial exploration phase is approximately $46 million, representing the acquisition of 900 square kilometres of 3D seismic data and the drilling of 19 wells. The initial exploration term expires on June 15, 2012 for Blocks LLA-16 and LLA-20, and on October 5, 2012 for Blocks LLA -29 and LLA-30.

Seismic activities of the Company in Colombia since inception include: (i) the acquisition, processing and evaluation of approximately 950 km^2 of three-dimensional ("**3D**") seismic on Block LLA-16, Block LLA-20, Block LLA-29 and Block LLA-30. In 2011, the Company expects to acquire and process an additional 135 km^2 of 3D seismic on Block LLA-20,165 km^2 of 3D seismic on Block LLA-57 and 80 km^2 of 3D seismic on Block LLA-16.

The Company commenced drilling operations on a total of six wells in Colombia in 2010 with four wells being rig released by year end 2010. The wells were drilled to a depth ranging between 8,100 ft and 13,250 ft. During January 2011, two additional wells (Kopi-1 and Kona-3) were spudded and the Kona-4 well was spudded in March 2011.

The Company has announced one commercial oil discovery in LLA-16 with the drilling of the Kona-1 well and the successful follow up well at Kona-2a. Production from the Kona-1 well commenced in December 2010 while production from the Kona 2a well was delayed waiting the deepening of the well to the Gacheta formation in March 2011. Along a new fault trend in Block LLA-16 the Supremo-1 well was drilled to a depth of 12,035 feet and recently tested. The well produced on pump approximately 2,500 bfpd from the Mirador formation, with a 31 degree API oil rate of 500 bopd. The Supremo-1 well is currently suspended. Technical analysis has determined that Supremo-1 was drilled off structure and it is planned in 2011 to drill Supremo-2 from the same pad to a position up dip of the original bottom hole location to attempt to locate the top of the structure.

Along the same fault trend as Supremo-1, the Goroka-1 well was drilled to a depth of 12,037 feet. The well was tested in the Gacheta, Mirador and C7 formations which were all determined to be water bearing. This well has been converted to a water disposal well to allow production from the Supremo-1 well and any follow up wells to this discovery. The Kona-3 appraisal well and Kopi-1 exploration well were both cased and are scheduled to be completed.

In Block LLA-20, both the Conoto-1 and Zocay-1 wells commenced drilling in 2010 with the Conoto-1 well being rig released in 2010 and the Zocay-1 well expected to be rig released in early 2011. The log response on the Conoto-1 well was ambiguous so the well was cased for testing. Testing of the Conoto-1 reservoirs indicated that all of the zones were water bearing. With the results from Conoto-1, the Zocay-1 well was drill and abandoned.

Production at Kona began at an initial gross test rate of 500 bopd and was increased up to approximately 2,900 bopd. The company completed a 7km pipeline installation to transport oil from the Kona wellsite to a roadside loading facility built along a paved road. The company is currently constructing a 25,000 bfpd facility at the Kona wellsite to process produced fluid volumes from the Kona wells after which pipeline specification oil will be shipped to the roadside loading facility for sales. The facility is expected to commence operations early in Q2, 2011. Plans for Colombia in 2011 include drilling 16-20 gross wells, subject to regulatory approvals, and acquiring an additional 380 km^2 of 3D seismic.

Parex Colombia has not entered into any commodities forward price contracts or commodity derivatives contracts.

For the year ended December 31, 2010, GLJ assigned 2,131 mbbl of gross proved reserves (1,066 net) and 11,708 mbbl of gross proved plus probable reserves (5,854 net) in Colombia, based on forecasted prices.

Trinidad & Tobago

Parex Trinidad has the right to explore for hydrocarbons in the prolific Southern Basin of onshore Trinidad. Parex Trinidad has interest in the Central Range Blocks and the Moruga Block.

Currently, Parex Trinidad has no oil and natural gas production or oil and natural gas reserves.

Central Range Blocks

Parex Trinidad's acreage holdings include a 50% working interest in the Central Range Blocks. The PSCs for the Central Range Blocks grant an interest in on-shore land covering a total surface area of approximately 211,000 gross acres (105,500 net), with the Central Range Shallow Block PSC governing rights to a depth of 4,500 feet below land surface and the Central Range Deep Block PSC governing rights for depths greater than 4,500 feet (the "**Contract Area**").

The PSCs have minimum work commitments in the initial 48-month exploration phase of the contracts which total 100 kilometres of 2D seismic, 168 square kilometres of 3D seismic, one deep well drilled to a minimum depth of 12,000 feet and two shallow wells drilled to 4,500 feet or less. Under the terms of the JVA with VETL, Parex Trinidad will pay 100% of the first $10 million of seismic acquisition costs during the exploration phase. As of December 31, 2009, Parex Trinidad's remaining commitments in the initial exploration phase, including the remaining VETL carry, were estimated to be $16 million. Parex Trinidad has begun its exploration efforts and has completed an airborne geophysical survey over the entire area of the Central Range Blocks and a 216 kilometre 2D seismic acquisition program.

Parex Trinidad has entered into joint operating agreements with VETL and the Petroleum Company of Trinidad & Tobago ("**Petrotrin**") respecting the operations of each of the Central Range Blocks. These joint operating agreements provide Petrotrin with the right to participate for a 35 percent net working interest in any development on the Central Range Shallow Block and for a 20 percent net working interest in any development on the Central Range Deep Block. (Parex Trinidad, VETL and Petrotrin are collectively referred to as the "**Contractor**").

Parex Trinidad and VETL pay 100 percent of the minimum work commitment costs in the exploration term of the PSCs. Parex Trinidad will pay 100 percent of the first $10 million of seismic costs in the exploration term, and the remainder of the work commitment costs will be shared 50 percent by each of Parex Trinidad and VETL.

The PSCs provide for a 48-month exploration phase which was subsequently extended to 60 months. Following this period, the Contractor has the option to enter into two consecutive exploration phases of 12 months each, subject to certain MEEI defined criteria.

The stated minimum work commitments for each phase are as follows:

Phase	Term	Seismic Commitment	Drilling Commitment
First	5 years	*Central Range Blocks combined* 100 kilometres of 2D seismic 168 square kilometres of 3D seismic evaluate, integrate and map all geological and seismic data related to the Contract Area	*Central Range Shallow Block*[(1)] two wells drilled to 4,500 feet or less, with spudding of first well not later than March 18, 2011 *Central Range Deep Block*[(1)] one well drilled to a minimum depth of 12,000 feet, with spudding not later than March 18, 2011
Second (optional)	1 year	*Central Range Blocks combined* 200 square kilometres of 3D seismic evaluate, integrate and map all geological and seismic data related to the Contract Area	*Central Range Shallow Block*[(1)] two wells drilled to 4,500 feet or less *Central Range Deep Block*[(1)] no requirement
Third (optional)	1 year	*Central Range Blocks combined* evaluate, integrate and map all geological and seismic data related to the Contract Area	*Central Range Shallow Block*[(1)] one well drilled to 4,500 feet or less *Central Range Deep Block*[(1)] one well drilled to a minimum depth of 12,000 feet

Notes:

(1) Parex Trinidad intends to apply for an extension of the spud date requirement to equalize with the First Phase extension from 48 months to 60 months, which extension is expected to be granted.

The terms of the PSCs require that a portion of the Contract Area be relinquished at the end of each exploration phase. The relinquishment requirements are:

(a) at least 40 percent of the original Contract Area, not later than the end of the first exploration phase period (September 18, 2013 at the latest);

(b) at least 50 percent of the original Contract Area (inclusive of areas previously relinquished), not later than the end of the second exploration phase period;

(c) all portions of the original Contract Area, not later than the end of the third exploration phase period, except for production areas with a development plan that has been approved by the government; and

(d) any production area not in commercial production within five years after declaration of commercial discovery.

Notwithstanding the above, relinquishments may be deferred in the following circumstances:

(a) upon the discovery of oil or natural gas with commercial potential, the Contractor shall present an appraisal program to the government specifying the necessary appraisal work including additional seismic, drilling and studies and a time frame within which the appraisal program will be completed. Any areas currently subject to an appraisal program will be exempt from the relinquishments outlined above until such time as the appraisal program has been completed. At the end of the appraisal program, any area not declared a commercial discovery will be relinquished; and

(b) where the Contractor has declared a commercial discovery during the exploration period, the Contractor has the option to retain up to 20 percent of the original Contract Area upon approval of an extended exploration work program for the remainder of that calendar year and the next two calendar years. At the end of that period, the Contractor may apply for a further extension of the exploration work program for two calendar years. At the end of the extended exploration period(s), any area not declared a commercial discovery will be relinquished.

If a commercial discovery is made, the Contractor must submit a development plan for the area. Upon approval of the development plan by the government, the area is deemed to be a production area. The term of the PSCs for any production area will be 25 years from September 18, 2008. At the end of the 25-year term, the Contractor may apply for extensions based on terms and conditions to be negotiated at that time. Each extension will be for a five-year term.

Ownership of the oil and natural gas rights, as well as all assets used in connection with operations, shall revert to the government of Trinidad & Tobago when any area is relinquished or at the end of the contract (whichever first occurs).

Under the terms of the PSCs, there are no royalties payable on production from Crown lands. Instead, the government of Trinidad & Tobago takes in-kind a share of "Profit Oil" and "Profit Natural Gas" as calculated in accordance with the terms of the PSCs. The government's share will vary depending on the sales prices for oil and natural gas, average daily production rates, cumulative production volumes and the cumulative amount of capital and operating costs that have been recovered by the Contractor. In general, the government's share will increase at higher commodity prices, higher average daily production rates, higher cumulative production volumes and after cumulative capital and operating costs have been recovered.

The Central Range Blocks are expected to be oil plays. Therefore, the disclosure presented below is for oil production. In general, the government's share of any natural gas production would be less than for oil.

Profit Oil ("**Profit Oil**") is the difference between total oil production and cost recovery oil. Cost recovery oil is allocated 100 percent to the Contractor. The cost recovery oil share of total production will be:

Cumulative production (bbls of oil)	**Cost recovery volume**
Less than or equal to 25,000,000 bbls	50%
25,000,001 to 50,000,000 bbls	45%
Greater than 50,000,000 bbls	40%

Cost recovery volumes are subject to annual maximums that limit the Contractor's recovery to 100 percent of current year operating costs, 100 percent of current year exploration costs and a portion of current and prior year development costs. Costs not recovered in the current year are carried forward and included in future years' cost recovery calculations. Generally, in the early years of the PSCs, cost recovery oil volumes allocated to the Contractor will be the highest. However, as the Contractor recovers its cumulative capital costs, the cost recovery oil volumes will decrease and Profit Oil volumes will increase. This means that the government will be allocated higher proportions of total production and the Company's share of total production will be reduced.

The government's share of Profit Oil is determined on a sliding scale basis based on sales price and average daily production. At average sales prices in excess of $20 per bbl, the government's share is a variable amount increasing with the price of oil. The following table shows the government's share of Profit Oil for a selection of price levels.

Monthly	**Sales Value of Oil**							
Production	**$20/bbl**	**$30/bbl**	**$40/bbl**	**$50/bbl**	**$60/bbl**	**$80/bbl**	**$100/bbl**	**$120/bbl**
Up to 10,000 bbls/d	25%	30%	36%	54%	60%	67%	71%	74%
> 10,000 bbls/d up to 25,000 bbls/d	30%	35%	42%	55%	60%	68%	72%	75%
> 25,000 bbls/d up to 50,000 bbls/d	35%	40%	46%	60%	65%	71%	75%	78%
> 50,000 bbls/d up to 75,000 bbls/d	40%	45%	52%	62%	67%	73%	77%	79%
In excess of 75,000 bbls/d	45%	50%	55%	66%	71%	76%	79%	81%

The cost recovery oil and Profit Oil volumes are calculated independently for each PSC. Therefore, the rates may vary between production from the Central Range Shallow Block versus the Central Range Deep Block.

Under the terms of the PSCs, a signing bonus of $5.5 million (gross) was paid on September 18, 2008 by Voyager. The PSCs also set out requirements for various other annual payments such as lease rentals, administration, research and development and donations to the University of Trinidad & Tobago. Production bonus payments will be required if average daily production levels reach certain targets, starting at a $2 million bonus if production in either block reaches 25,000 bbls/d. The signing bonus, production bonuses and other payments are not allowed to be included in the cost recovery calculation.

Parex Trinidad has not yet commenced drilling on the Central Range Block but has received regulatory approval to drill two shallow exploration wells in 2011.

Moruga Block

Parex Trinidad has entered into the Farm-In for the Moruga Block under which, subject to fulfilling the farm-in exploration commitments, it will earn a 50% working interest in the property which comprises 11,970 gross acres (5,985 acres net).

The Moruga Block was granted on August 29, 2007 to Primera Oil and Gas Limited. Primera Oil and Gas Limited subsequently assigned 33% of its interest in the Licence to Primera Energy Resources Ltd.

The terms of the Licence required Primera to complete the acquisition and processing of 56 km^2 of 3D seismic by August 27, 2008 and to drill two exploration wells to a depth of at least 10,500 feet each, with spudding of the first such well to be not later than August 27, 2009. Primera fulfilled the 3D seismic commitment within the time allowed. On August 26, 2009, the MEEI granted Primera a six-month extension to spud the first well and reduced the drilling commitment to drilling of two explorations wells with one well to a depth of 10,500 feet.

Parex Trinidad will earn a 50% working interest in the Moruga Block by paying 95% of all costs, to a maximum of $13.3 million, for drilling and evaluating these two exploration wells.

Primera has provided MEEI with a performance guarantee of $12.5 million as required under the Licence. Parex Trinidad will contribute its 50% share of the guarantee upon assignment of its interest in the Licence. Parex Trinidad intends to apply for a reduction of the guarantee related to the seismic commitment work already performed.

The term of the Licence is for six years from August 27, 2007. At the end of the fourth year, 50% of the acreage must be surrendered. At the end of the sixth year, all acreage not considered to be part of a commercial discovery (as defined in the Licence) must be relinquished. For all fields considered to be a commercial discovery the Licence will be extended for a term of 25 years from August 27, 2007. At the end of the 25-year term, the Licence allows for renewal periods of five years at time, based on terms to be negotiated at that time.

Under the terms of the Licence, Parex Trinidad will be subject to royalties, Petroleum Production Levy, Supplemental Petroleum Tax, Green Fund Levy, Unemployment Levy and Petroleum Profits tax (refer to Industry Conditions section). The Licence also sets out requirements for various other annual payments such as lease rentals, training, research and development and scholarships. Production bonuses will be required if average daily production levels reach certain targets, starting with a $1.5 million bonus if production reaches 25,000 bbls/d.

The Company has drilled two exploration wells on the Moruga Block. Firecrown-1 reached a total measured depth of 8,701 feet and was cased to a depth of 8,400 feet. Snowcap-1 was drilled and cased in the third quarter of 2010 to a depth of 8,600 feet. Environment approval for the multi-zone testing program for Snowcap-1 was received on November 11, 2010 and Parex commenced testing the well in early December, 2010. The Firecrown-1 well is not expected to be tested until 2011. The Snowcap-1 well tested the primary Herrera zone (4,590-4,605 feet) in a multi-point test over the perforated interval at 4,597-4,603 feet. The final four day gross rate averaged 580 bopd of 35 API oil and 5.4 mmscfd with wellhead pressure of 600 psi on a 48/64th inch choke under natural flow. The final six hours of flow on that choke averaged 500 bopd and 4.7 mmscfd at 580 psi. During the initial seven hour clean-up period, the zone flowed at rates averaging 1,166 bopd and 1.6 mmscfd at 1,200 psi. The well is currently shut-in to record down-hole pressure build-up for analysis of the test.

The Firecrown-1 well is scheduled to be deepened to the earning objective of 10,500 ft in the first half of 2011 after which the well will be completed to test the primary objectives that were encountered in the shallower section of the well along with any additional zones of interest encountered in the deepening.

Parex Trinidad current plans in 2011 are to drill 3-5 gross wells on the Moruga and Central Range Blocks, subject to regulatory approval, and acquire 168 km^2 of 3D seismic.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Reserves Data**") is dated December 31, 2010. The effective date of the Reserves Data is December 31, 2010 and the preparation date of the Reserves Data is January 31, 2011. All of the Company's reserves are located in Colombia.

Disclosure of Reserves Data

The reserves data set forth below are based upon an evaluation by GLJ with an effective date of December 31, 2010 contained in the GLJ Report. The Reserves Data summarize the oil, NGLs and natural gas reserves of the Company and the net present values of future net revenue for such reserves using forecast prices and costs as at December 31, 2010. The crude oil, NGLs and natural gas reserve estimates presented in the GLJ Report are based on the guidelines contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth in the glossary to this Annual Information Form. GLJ was engaged to provide evaluations of proved reserves and proved plus probable reserves and proved plus probable plus possible reserves. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Company believes is important to the readers of this information.

The Operations and Reserves Committee of the Board of Directors has reviewed and approved the GLJ Report. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator or Auditor are attached as Schedules "A" and "B" hereto, respectively.

All evaluations of future revenue contained in the GLJ Report are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein.

In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows there from are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Company's properties may vary from the information presented herein and such variations could be material. In addition, there is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material.

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

In certain of the tables set forth below, the columns may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2010
FORECAST PRICES AND COSTS

Reserve Category	Light and Medium Oil		Heavy Oil		Coalbed Methane		Natural Gas (non-associated & associated)		Natural Gas Liquids		Total Oil Equivalent	
	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED												
Developed Producing	433	398	-	-	-	-	-	-	-	-	433	398
Developed Non-Producing	0	0	-	-	-	-	-	-	-	-	0	0
Undeveloped	633	582	-	-	-	-	-	-	-	-	633	582
TOTAL PROVED	1,066	980	-	-	-	-	-	-	-	-	1,066	980
PROBABLE	4,788	3,620	-	-	-	-	-	-	-	-	4,788	3,620
TOTAL PROVED PLUS PROBABLE	5,854	4,600	-	-	-	-	-	-	-	-	5,854	4,600
POSSIBLE	4,585	3,109	-	-	-	-	-	-	-	-	4,585	3,109
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	10,439	7,709	-	-	-	-	-	-	-	-	10,439	7,709

Note:

(1) "Gross Reserves" are the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves. See *Certain Definitions*.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2010
FORECAST PRICES AND COSTS

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/ year[1]
Reserves Category	**0 ($000's)**	**5 ($000's)**	**10 ($000's)**	**15 ($000's)**	**20 ($000's)**	**0 ($000's)**	**5 ($000's)**	**10 ($000's)**	**15 ($000's)**	**20 ($000's)**	**($/boe)**
PROVED											
Developed Producing	19,625	18,957	18,349	17,792	17,281	19,625	18,957	18,349	17,792	17,281	46.10
Developed Non-Producing											
Undeveloped	32,339	28,978	26,183	23,831	21,833	27,930	24,866	22,331	20,209	18,415	44.99
TOTAL PROVED	51,964	47,935	44,531	41,624	39,114	47,555	43,822	40,679	38,001	35,696	45.44
PROBABLE	199,644	178,746	161,830	147,894	136,239	136,631	121,105	108,642	98,458	90,008	44.70
TOTAL PROVED PLUS PROBABLE	251,607	226,681	206,361	189,518	175,353	184,186	164,928	149,321	136,460	125,704	44.86
POSSIBLE	192,485	159,287	134,668	115,886	101,205	129,264	106,576	89,784	77,000	67,029	43.30
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	444,092	385,968	341,029	305,404	276,558	313,450	271,503	239,105	213,460	192,733	44.23

Note:

(1) The unit values are based on net reserve volumes.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
as at December 31, 2010
FORECAST PRICES AND COSTS

Reserves Category	Revenue (000$)	Royalties (000$)	Operating Costs (000$)	Development Costs (000$)	Abandonment and Reclamation Costs (000$)	Future Net Revenue Before Income Taxes (000$)	Income Taxes (000$)	Future Net Revenue After Income Taxes (000$)
Proved Reserves	75,623	6,858	12,184	4,449	168	51,964	4,409	47,555
Proved Plus Probable Reserves	420,262	95,839	38,217	33,971	628	251,607	67,421	184,186
Proved Plus Probable Plus Possible Reserves	763,073	210,217	65,235	42,749	780	444,092	130,641	313,450

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (000$)	UNIT VALUE ($/boe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	44,531	45.44
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Non-Conventional Oil and Gas Activities (coalbed methane)	-	-
	TOTAL	44,531	45.44
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	206,361	44.86
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Non-Conventional Oil and Gas Activities (coalbed methane)	-	-
	TOTAL	206,361	44.86
Proved Plus Probable Plus Possible Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	341,029	44.23
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	-	-
	Non-Conventional Oil and Gas Activities (coalbed methane)	-	-
	TOTAL	341,029	44.23

Note:

(1) The unit values are based on net reserve volumes.

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2010, reflected in the Reserves Data. These price assumptions were provided to Parex by GLJ and were GLJ's then current forecast at the date of the GLJ Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS(1)
as of December 31, 2010
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Light Sweet Crude Oil at Edmonton 40° API ($Cdn/bbl)	Medium Crude Oil 29° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Natural Gas AECO-C Spot ($Cdn/MMBtu)	Natural Gas Liquids Edmonton Pentanes Plus ($Cdn/bbl)	Natural Gas Liquids Edmonton Butanes ($Cdn/bbl)	Inflation Rates[2] (%/Year)	Exchange Rate[3] ($US/$Cdn)
2010	79.42	78.02	73.81	60.62	4.17	84.04	65.69	1.8	.971
Forecast[4]									
2011	88.00	86.22	82.78	68.79	4.16	90.54	67.26	2.0	.98
2012	89.00	89.29	83.04	68.33	4.74	91.96	68.75	2.0	.98
2013	90.00	90.92	83.68	67.03	5.31	92.74	70.01	2.0	.98
2014	92.00	92.96	84.59	67.84	5.77	94.82	71.58	2.0	.98
2015	95.17	96.19	87.54	70.23	6.22	98.12	74.07	2.0	.98
2016	97.55	98.62	89.75	72.03	6.53	100.59	75.94	2.0	.98
2017	100.26	101.39	92.26	74.08	6.76	103.42	78.07	2.0	.98
2018	102.74	103.92	94.57	75.95	6.90	106.00	80.02	2.0	.98
2019	105.45	106.68	97.08	78.00	7.06	108.82	82.15	2.0	.98
2020	107.56	108.84	99.04	79.59	7.21	111.01	83.80	2.0	.98
Thereafter	Escalated oil, gas and product prices at 2.0% per year thereafter.								

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting prices and costs.
(3) The exchange rate used to generate the benchmark reference prices in this table.
(4) As at December 31.

Weighted average historical prices for the year ended December 31, 2010, were $US79.42/bbl for crude oil at Cushing, Oklahoma.

Reserves Reconciliation

As the Company did not have any reserves for the year ended December 31, 2009 and there is no evaluation report available to the Company for the year ended December 31, 2009, pursuant to NI 51-101, a reserves reconciliation is not required to be disclosed.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves are planned to be developed over the next two years.

In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see *Risk Factors* herein.

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Parex' assets for the years ended December 31, 2010, 2009 and 2008 and, in the aggregate, before that time based on forecast prices and costs. All of the Company's proved undeveloped reserves and the probable undeveloped reserves are located in Colombia.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-
2010	633	633	-	-	-	-	-	-

The GLJ Report disclosed company gross proved undeveloped reserves of 633 mbbl before royalties. These are reserves which can be estimated with a high degree of certainty to be recoverable, provided a significant expenditure is made to render them capable of production. The Company believes it has or will have capital spending plans in place during 2011 and 2012 to drill the necessary locations and to construct the necessary facilities to permit these proved undeveloped reserves to be reclassified as proved developed reserves. These expenditures are reflected in the future development costs disclosed herein.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto								
2008	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-
2010	4,609	4,609	-	-	-	-	-	-

The GLJ Report disclosed company gross probable undeveloped reserves of 4,609 mbbl before royalties. Probable reserves are less certain to be recovered than proved reserves. The Company believes that it has or will have capital spending plans in place during 2011 and 2012 to drill the necessary locations to permit these probable reserves to be reclassified as proved. However, this reclassification will also depend in large part upon the performance of new and existing wells.

See *Principal Properties* and *Statement of Reserves Data and Other Information – Additional Information Relating to Reserves Data - Future Development Costs* for a description of the Company's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

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

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) based upon the GLJ Report.

($000s)	**Total Proved Estimated Using Forecast Prices and Costs**	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs**
2010	-	-
2011	2,817	20,850
2012	1,632	9,792
2013	-	3,329
2014	-	-
2015	-	-
Total for all years undiscounted	4,449	33,971
Total for all years discounted at 10% per year	4,100	30,991

Parex expects to use a combination of internally generated cash from operations and the issuance of new equity where and when it believes appropriate to fund future development costs set out in the GLJ Report. There can be no guarantee that funds will be available or that the board of directors of the Company will allocate funding to develop all of the reserves attributable in the GLJ Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of any of the Company's properties uneconomic.

Other Oil and Natural Gas Information

Oil and Natural Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a working interest as at December 31, 2010.

	Oil Wells				Gas Wells				Other Wells[(3)]	
	Producing		Non-Producing		Producing		Non-Producing			
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Colombia	1	0.5	2	1	0	0	0	0	1	0.5
Trinidad	0	0	0	0	0	0	0	0	2	1.0

Notes:

(1) "Gross" means the total number of wells in which the Company has an interest.
(2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.
(3) Includes service, disposal, injection and standing wells.

Properties with No Attributed Reserves

The following table sets out Parex and its Subsidiaries' developed and undeveloped land holdings as at December 31, 2010, including Block LLA-57.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Colombia	103	52	593,429	348,980	593,532	349,032
Trinidad	-	-	222,970	111,485	222,970	111,485

All of Parex and its Subsidiaries' unproved properties are located in Trinidad & Tobago and Colombia. See *Principal Properties*. Parex does not expect its rights to explore, develop and exploit any of its undeveloped properties to expire within the next year.

Forward Contracts

See Note 16, "Financial Instruments and Financial Risk Management" and Note 18, "Commitments", to the consolidated financial statements of the Company for the year ended December 31, 2010, which information is incorporated herein by reference and can be found on the Company's website at www.parexresources.com and on SEDAR at www.sedar.com. The nature of the crude oil operations exposes the Company to risks associated with fluctuations in commodity prices and foreign currency exchange rates. Periodically, the Company may manage these risks through the use of derivative instruments. The Board of Directors of the Company periodically reviews the results of all risk management activities an all outstanding positions. Currently, there are no risk management contracts outstanding.

Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates well abandonment and reclamation costs area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue. The expected total abandonment and reclamation costs included in the GLJ Report for 1.5 net wells under the proved reserves category is $168,000 undiscounted ($93,000 discounted at 10 percent) based on forecast prices and costs.

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

Forecast Prices and Costs ($000's)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2010	-	-
2011	-	-
2012	-	-
2013	-	-
Thereafter	168	628
Total Undiscounted	168	628
Total Discounted @ 10%	93	320

Tax Horizon

The GLJ report forecasts cash taxes in Colombia to be incurred in 2011. The tax horizon for Parex Trinidad depends upon the level of success, if any, in finding and producing oil and natural gas in Trinidad.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties for the year ended December 31, 2010:

	Property Acquisition Costs ($000's)			
Country	**Proved Properties**	**Unproved Properties**	**Exploration Costs ($000's)**	**Development Costs ($000's)**
Colombia	-	-	18,973	10,052
Total	-	-	18,973	10,052

Exploration and Development Activities

The following table sets forth the gross and net exploratory, appraisal and development wells in which the Company participated during the year ended December 31, 2010:

Colombia

	Exploratory		Appraisal		Development		Injection		Total	
	Gross[(1)]	**Net[(2)]**	**Gross[(1)]**	**Net[(2)]**	**Gross[(1)]**	**Net[(2)]**	**Gross[(1)]**	**Net[(2)]**	**Gross[(1)]**	**Net[(2)]**
Oil	4	2	0	0	0	0	0	0	4	2
Gas	-	-	-	-	-	-	-	-	-	-
Service	-	-	-	-	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-	-	-	-	-
Dry	-	-	-	-	-	-	-	-	-	-
Total	4	2	-	-	-	-	-	-	4	2
Success										

Notes:

(1) "Gross" means the total number of wells in which the Company has an interest.
(2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.

Trinidad & Tobago

	Exploratory		Appraisal		Development		Injection		Total	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Oil	2	1	0	0	0	0	0	0	2	1
Gas	-	-	-	-	-	-	-	-	-	-
Service	-	-	-	-	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-	-	-	-	-
Dry	-	-	-	-	-	-	-	-	-	-
Total	2	1	-	-	-	-	-	-	2	1
Success										

Notes:

(1) "Gross" means the total number of wells in which the Company has an interest.
(2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.

See *Principal Properties* for a description of Parex and its Subsidiaries' current and proposed exploration and development activities.

Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the Canadian Institute of Chartered Accountants' standard. This standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition. Under the standard, the estimated fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Company's credit adjusted risk-free interest rate. The obligation is reviewed regularly by Management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold. Actual restoration expenditures are charged to the accumulated obligation as incurred. The related cost is recognized as an asset and is included in costs subject to depletion.

In the Company's audited and consolidated financial statements as at December 31, 2010, the estimated total undiscounted amount required to settle the asset retirement obligations in respect of the Company's producing and non-producing wells was approximately $1.4 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 20 years. The 9 percent discounted present value of this amount is approximately $256,000. The Company does not expect to incur any of these expenditures over the next three financial years.

Production Estimates

The following table sets out the volume of the Company's yearly average production estimated in the GLJ Report for the year ended December 31, 2011, that is reflected in the estimate of future net revenue disclosed in the tables contained under *Statement of Reserves Data and Other Oil and Gas Information – GLJ Report*.

	Light and Medium Oil (bbls/d)		Heavy Oil (bbls/d)		Natural Gas (Mcf/d)		Natural Gas Liquids (bbls/d)		Total (boe/d)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved										
Producing	777	717	-	-	-	-	-	-	777	717
Developed Non-Producing	-	-	-	-	-	-	-	-		
Undeveloped	339	312	-	-	-	-	-	-	339	312
Total Proved	1,116	1,029	-	-	-	-	-	-	1,116	1,029
Total Probable	2,839	2,600	-	-	-	-	-	-	2,839	2,600
Total Proved Plus Probable	3,955	3,629	-	-	-	-	-	-	3,955	3,629
Total Possible	696	650	-	-	-	-	-	-	696	650
Total Proved Plus Probable Plus Possible	4,651	4,279	-	-	-	-	-	-	4,651	4,279

Note:

(1) The Kona discovery located in Block LLA 16 accounts for 100% of the Company's total production estimate set forth herein.

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of the last financial year, excluding the immaterial minor Canadian properties which were sold in 2010. The Company did not commence production until late November, 2010.

	Quarter Ended 2010				Year Ended 2010
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**December**
Average Daily Sales[1]					
Light and Medium Oil (Bbls/d)	306	-	-	-	77
Heavy Oil (Bbls/d)	-	-	-	-	-
Gas (Mcf/d)	-	-	-	-	-
NGLs (Bbls/d)	-	-	-	-	-
Combined (BOE/d)	306	-	-	-	77
Average Price Received (net of transportation)					
Light and Medium Oil ($/Bbl)	70.53	-	-	-	70.53
Heavy Oil ($/Bbls)	-	-	-	-	-
Gas ($/Mcf)	-	-	-	-	-
NGLs ($/Bbls)	-	-	-	-	-
Combined ($/BOE)	70.53	-	-	-	70.53
Royalties Paid					
Light and Medium Oil ($/Bbls)	6.36	-	-	-	6.36
Heavy Oil ($/Bbls)	-	-	-	-	-
Gas ($/Mcf)	-	-	-	-	-
NGLs ($/Bbls)	-	-	-	-	-
Combined ($/BOE)	6.36	-	-	-	6.36

	Quarter Ended 2010				Year Ended 2010
	Dec. 31	Sept. 30	June 30	Mar. 31	December
Operating and Transportation Expenses ($/BOE)					
Light and Medium Oil ($/Bbls)	28.25	-	-	-	28.25
Heavy Oil ($/Bbls)	-	-	-	-	-
Gas ($/Mcf)	-	-	-	-	-
NGLs ($/Bbls)	-	-	-	-	-
Combined ($/BOE)	28.25	-	-	-	28.25
Netback Received ($/BOE)(2)					
Light and Medium Oil ($/Bbls)	54.63	-	-	-	54.63
Heavy Oil ($/Bbls)	-	-	-	-	-
Gas ($/Mcf)	-	-	-	-	-
NGLs ($/Bbls)	-	-	-	-	-
Combined ($/BOE)	54.63	-	-	-	54.63

Notes:

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

The following table indicates the Company's total production volumes from its important fields for the year ended December 31, 2010:

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Kona, Colombia	77	-	-	-	77
Total	77	-	-	-	77

Parex Trinidad does not currently have and did not have any prior oil and natural gas production or oil and natural gas reserves in the year ended December 31, 2010.

DIVIDEND POLICY

Parex has not paid any dividends on the outstanding Common Shares. The Board of Directors of Parex will determine the actual timing, payment and amount of dividends, if any, that may be paid by Parex from time to time based upon, among other things, the level of cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other business considerations as the Board of Directors of Parex considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Company consists of an unlimited number of Common Shares without nominal or par value. As at March 8, 2011, there were 77,155,368 Common Shares issued and outstanding. The following is a description of the rights, privileges, instructions and conditions attaching to the share capital of the Company.

The holders of Common Shares are entitled: (i) to dividends if, as and when declared by the Board of Directors; (ii) to vote at any meetings of the holders of Common Shares of the Company; and (iii) upon liquidation, dissolution or winding up of the Company, to receive the remaining property and assets of the Company.

On September 29, 2009, the Board of Directors of Parex approved the adoption of a shareholder protection rights plan (the "**Parex Shareholder Rights Plan**"), which Parex Shareholder Rights Plan was approved by shareholders of PARI on October 30, 2009. Pursuant to the Parex Shareholder Rights Plan, one right ("**Right**") is attached to each Common Share. The Rights will separate from the Common Shares to which they are attached and will become exercisable upon the occurrence of certain events in accordance with the Parex Shareholder Rights Plan. Subject to adjustment as provided in the Parex Shareholder Rights Plan, each Right will entitle the holder to purchase one Common Share at a price equal to $50.00 (the "**Exercise Price**") and, in the event of a "Flip-In Event", as that term is defined in the Parex Shareholder Rights Plan, each Right will constitute the right to purchase from the Company, upon payment of the Exercise Price and otherwise exercising such Right in accordance with the terms of the Parex Shareholder Rights Plan, that number of Common Shares having an aggregate Market Price (as defined in the Parex Shareholder Rights Plan), on the date of consummation or occurrence of such Flip-In Event equal to four times the Exercise Price for an amount in cash equal to the Exercise Price. The Parex Shareholder Rights Plan is similar to plans adopted recently by several other Canadian issuers and approved by their securityholders. A copy of the Parex Shareholder Rights Plan is available on the Company's SEDAR profile at www.sedar.com.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSXV under the symbol "PXT".

The following sets forth the price range and volume of the Common Shares traded or quoted on the TSXV (as reported by such exchange) for the periods indicated, in Canadian dollars.

	Price Range		
	High ($/share)	**Low ($/share)**	**Volume**
2010			
January	4.75	4.07	2,042,353
February	4.50	4.11	1,080,012
March	5.00	4.26	2,960,840
April	5.70	4.65	2,595,280
May	5.31	3.50	1,404,395
June	4.90	3.89	1,185,543
July	5.80	4.00	2,027,592
August	6.00	5.30	2,753,342
September	6.25	5.60	1,418,013
October	6.83	5.75	1,656,698
November	8.80	6.21	2,381,952
December	8.65	7.75	2,012,238
2011			
January	9.65	8.32	3,005,242
February	9.65	9.00	2,823,637
March (1 to 8)	9.30	8.93	319,244

ESCROWED SECURITIES

As at the date hereof, none of the Company's securities are subject to escrow.

DIRECTORS AND OFFICERS

The names, provinces and countries of residence, positions held with the Company, and principal occupation of the directors and officers of the Company during the past five years are set out below and in the case of directors, the period each has served as a director of the Company. Each of the directors and officers listed below were previously directors or officers of PARI.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer[(4)]	Principal Occupation (for last 5 years)
Norman McIntyre[(3)(4)(5)] Alberta, Canada	Director and Chairman since September 29, 2009	Independent Businessman since 2004. President of Petro-Canada from 2002 to 2004. Executive Vice President of Petro-Canada from 1995 to 2002.
Curtis Bartlett[(1)(5)] Alberta, Canada	Director since September 29, 2009	Co-founder and Managing Director of MHI Energy Partners, a private investment firm. Over 20 years experience as an entrepreneur and manager, private equity investor and investment banker. Director of several private companies.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer[4]	Principal Occupation (for last 5 years)
John Bechtold[2][3][5] British Columbia, Canada	Director since September 29, 2009	Currently a Director of Parkland Fuel Corporation, an independent marketer of fuels across Canada, Mr. Bechtold brings over 35 years of broad oil, gas and energy related experience. He served at Petro-Canada from 1977 until retirement in a number of leadership roles. Following retirement he has also served on the Board of Directors of the British Columbia Oil & Gas Commission which regulates oil and natural gas activity in that province.
Robert Engbloom, Q.C.[2][3][5] Alberta, Canada	Director since September 29, 2009	Partner with Macleod Dixon LLP, a law firm based in Calgary, Alberta and with offices in Toronto, Ontario and internationally. Mr. Engbloom has more than 30 years of experience in the areas of mergers and acquisitions, governance, corporate and securities law. His broad experience spans a range of businesses both public and private, operating nationally and internationally, primarily in the energy industry.
Wayne Foo[4] Alberta, Canada	President and Chief Executive Officer since September 29, 2009 and Director since August 28, 2009	Currently President and Chief Executive Officer of Parex. President and Chief Executive Officer of Dominion Energy Canada Ltd. from 1998 to October 2002, and then Consultant to March 2003. Director of Pengrowth Corporation, administrator of Pengrowth Energy Trust.
Barry Larson Alberta, Canada	Vice President Operations and Chief Operating Officer since September 29, 2009	Currently Vice President Operations and Chief Operating Officer of Parex. Director of Magdalena Ventures. Vice President of Operations of Vermilion Oil and Gas (Trinidad) Ltd. from January 2003 to May 2004. Co-founder and Vice President of Aventura Energy Inc. from 1999 to 2003, a company that operated in Trinidad & Tobago and Argentina.
Ron Miller[1][4][5] Alberta, Canada	Director since September 29, 2009	Co-founder and Director of MHI Energy Partners, a private equity investment firm. Director of several private companies including Rhino Legal Finance Inc., Durham Group Inc. and Dreadnought Energy Inc.
W.A. (Alf) Peneycad[2][4][5] Alberta, Canada	Director since September 29, 2009	Independent Businessman since 2006, including consulting to Macleod Dixon LLP. Previously Vice President, General Counsel and Chief Compliance Officer for Petro-Canada from 2003 to 2006. Vice President, General Counsel and Corporate Secretary of Petro-Canada prior to 2003. Director for several other Canadian public companies including NiMin Energy Corp., Canadian Wireless Trust, and R Split III Corp. where he holds positions on the Audit and Finance, Corporate Governance and Human Resource Committees.
Kenneth Pinsky Alberta, Canada	Vice President Finance, Chief Financial Officer and Corporate Secretary since September 29, 2009	Currently Vice President Finance, Chief Financial Officer and Corporate Secretary of Parex. Previously, Chief Financial Officer of a TSX listed Royalty Trust from 2001 to June 2004, and the Chief Financial Officer and director of a Canadian based private exploration and production company from September 2004 to January 2008.
David Taylor Alberta, Canada	Vice President Exploration and Business Development since September 29, 2009	Currently Vice President Exploration and Business Development of Parex. Prior thereto, Vice President, Exploration and International Operations with Husky Energy from August 2000 to July 2007 and Vice President, Exploration for Renaissance Energy from June 1998 to August 2000.
Paul Wright[1][4][5] Alberta, Canada	Director since September 29, 2009	Currently works as a financial consultant and sits on the Boards of Directors and is Chairman of the Audit Committee for both Pan Orient Energy Corp. and Brickburn Funds Inc., a mutual fund company. He also sits on the Board of Directors of two non-profit organizations. Mr. Wright is a Chartered Accountant with over 25 years of industry experience. He has worked in senior financial roles in both domestic and international oil and natural gas companies, including as the Vice President Finance and CFO of Niko Resources Ltd.

Notes:

(1) Member of the Finance and Audit Committee.
(2) Member of the Corporate Governance, Compensation and Human Resources Committee.
(3) Member of the Operations and Reserves Committee.
(4) Member of the Institute of Corporate Directors having completed the Directors Education Program.
(5) Parex' directors will hold office until the next annual general meeting of the Company's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at March 8 2011, the directors and officers of Parex, as a group, beneficially owned or controlled or directed, directly or indirectly, 9,036,504 Common Shares or approximately 12 percent of the issued and outstanding Common Shares.

Cease Trade Orders

No current director or executive officer of the Company has, within the last ten years prior to the date of this Annual Information Form, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (ii) was subject to an order that resulted, after the director, executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Bankruptcies

No current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such person was acting in that 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 for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or securityholder.

Penalties or Sanctions

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

CONFLICTS OF INTEREST

The directors or officers of the Company may also be directors or officers of other oil and natural gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Company. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an 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 disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See *Risk Factors*.

FINANCE AND AUDIT COMMITTEE INFORMATION

Finance and Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Finance and Audit Committee of the Board of Directors is attached hereto as Schedule "C".

Composition of the Finance and Audit Committee

The members of the Finance and Audit Committee are Paul Wright, Ron Miller, and Curtis Bartlett. The members of the Finance and Audit Committee are independent (in accordance with National Instrument 52-110 – *Audit Committees*) and are financially literate. The following is a description of the education and experience of each member of the Finance and Audit Committee.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Paul Wright Calgary, Alberta (Chairman)	Yes	Yes	Currently works as a financial consultant and sits on the Boards of Directors and is Chairman of the Audit Committee for both Pan Orient Energy Corp. and Brickburn Funds Inc., a mutual fund company. He also sits on the Board of Directors of two non-profit organizations and was previously on the Audit Committee of PARI until the completion of the Arrangement in November 2009. Mr. Wright is a Chartered Accountant with over 25 years of industry experience. He has worked in senior financial roles in both domestic and international oil and natural gas companies, including as the Vice President Finance and CFO of Niko Resources Ltd.
Ron Miller Calgary, Alberta	Yes	Yes	Co-founder and Director of MHI Energy Partners, a private equity investment firm focused on the energy and environment sectors. Until January 2010 was a director and chair of the Audit Committee for COSTA Energy Inc., a company listed on the NEX. Until the completion of the Arrangement in November 2009, he acted as director and chair of the Audit Committee for PARI. He continues to act as a director for several private companies. Mr. Miller earned his Bachelor of Commerce degree from the University of Alberta in 1987 and his Chartered Accountant designation while articling with KPMG in 1990.
Curtis Bartlett Calgary, Alberta	Yes	Yes	Co-founder and Managing Director of MHI Energy Partners, a private investment firm. Over 20 years experience as an entrepreneur and manager, private equity investor and investment banker. Director of several private companies. Previously a director of PARI until the completion of the Arrangement in November 2009.

Pre Approval of Policies and Procedures

The Finance and Audit Committee has adopted a policy to review and pre approve any non audit services to be provided to Parex by the external auditors and consider the impact on the independence of such auditors. The Finance and Audit Committee may delegate to one or more independent members the authority to pre approve non audit services, provided that the member report to the Finance and Audit Committee at the next scheduled meeting such pre approval and the member comply with such other procedures as may be established by the Finance and Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

The Finance and Audit Committee has reviewed the nature and amount of non-audit services provided by PricewaterhouseCoopers LLP to the Company to ensure auditor independence. Fees paid to PricewaterhouseCoopers LLP for audit and non-audit services in the last fiscal year are outlined in the following table. Payments made in foreign currencies have been translated to Canadian dollars at average exchange rates for each year.

Nature of Services	Fees Paid to Auditor in the Year Ended December 31, 2010 (Cdn$)	Fees Paid to Auditor in the Year Ended December 31, 2009 (Cdn$)
Audit Fees[(1)]	260,123	63,537
Audit-Related Fees[(2)]	39,003	-
Tax Fees[(3)]	77,383	19,331
All Other Fees[(4)]	54,285	-
Total	430,794	82,868

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's consolidated financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include the review and assistance with transition to International Financial Reporting Standards.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.

(4) "All Other Fees" include all other non-audit products and services.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Company are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

The transfer agent and registrar for the Common Shares of the Company is Valiant Trust Company, and the Company's Common Shares are transferable at the offices of Valiant Trust Company in Calgary, Alberta and at the offices of BNY Trust Company of Canada in Toronto, Ontario.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Company, there are no material legal proceedings to which the Company is a party or of which any of their respective properties is the subject matter of, nor are there any such proceedings known to the Company to be contemplated.

During the year ended December 31, 2010 there were: (i) no penalties or sanctions imposed against the Company or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Company entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below, there were no material interests, direct or indirect, of directors or executive officers of the Company, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10 percent of the outstanding voting securities of the Company, or any other Informed Person (as defined in National Instrument 51-102 Continuous Disclosure Obligations) ("**NI 51-102**") or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Company or any of its subsidiaries.

As part of the Arrangement, Parex completed the Parex Management Private Placement of 3,333,333 Common Shares at a subscription price of Cdn$3.00 per share for gross proceeds of up to Cdn$10 million to certain directors, officers and employees of the Company. See *General Development of the Business*.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect other than the following:

1. The Parex Shareholder Rights Plan. See *Description of Capital Structure*; and

2. A General Security Agreement in favour of Export Development Canada in respect of the Letters of Credit provided to the ANH that guarantees the exploration commitments for the Colombian exploration blocks. See *Description of the Business and Operations*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by Parex other than GLJ, Parex' independent reserves evaluators and PricewaterhouseCoopers LLP, Chartered Accountants, Parex' auditors. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Parex or of Parex' associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Parex or of any associate or affiliate of Parex.

INDUSTRY CONDITIONS

The following is a brief summary of the economic and energy market conditions encountered in conducting oil and natural gas operations in Trinidad & Tobago and Colombia. The industry related information in this section has been taken from public sources.

Trinidad & Tobago

Economic

According to the Economic Intelligence Unit Country Forecast (January 2011), real GDP growth in Trinidad & Tobago was 1.1 percent in 2010 and is expected to grow by 1.9 percent in 2011. Inflation was 14.1 percent in 2010 and is expected to fall to 5.7 percent in 2011. The exchange rate of Trinidad & Tobago dollars to U.S. dollars is expected to remain consistent in 2011 at approximately 6.3 to 1.

Royalties, Petroleum Production Levy, Supplemental Petroleum Tax and Green Fund Levy

Royalties on State lands vary between onshore and offshore licences, and between oil and natural gas. The standard oil/condensate rate is 12.5 percent. The onshore Lease Operatorships and Farm-Outs must often pay an over-riding royalty to the state which can add up to a further 35 percent. Royalties on freehold lands are subject to negotiation, but tend to be consistent with the Crown royalty rate.

Producers must also pay a Petroleum Production Levy ("**PPL**") and Supplemental Petroleum Tax ("**SPT**"). The PPL is up to 4 percent of gross income from crude oil for producers of more than 3,500 barrels of oil per day. SPT is charged on production of oil based on an oil price-sensitive rate. The maximum rate is 18 percent for oil prices in excess of $49.50 per bbl, for licences granted after 1988. SPT is computed on gross income less allowances for royalty payments. The Green Fund Levy is charged at a rate of 0.1 percent on gross sales.

Under the terms of the Central Range Block PSCs, the government's share of Profit Oil will be collected in lieu of the Royalty, Production Levy and SPT. There is no exemption from the Green Fund Levy. The Moruga property will be subject to royalties and all the other taxes and levies noted above.

Income Taxes

The fiscal regime in Trinidad & Tobago is an enhanced two-tier system consisting of the production-based Royalty, Petroleum Production Levy and SPT supported by a profits-based corporation tax which includes the Petroleum Profits Tax ("PPT") and an Unemployment Levy. The PPT rate is 50 percent and the Unemployment Levy is 5 percent. Incentives and allowances are structured into the system to encourage investment, particularly in exploration projects and enhanced oil recovery schemes. PPT losses can be carried forward indefinitely.

Regulatory Regime

The petroleum industry in Trinidad & Tobago is principally governed by the *Petroleum Act* (1969) (the "**Petroleum Act**"), the Petroleum Regulations (1970) made thereunder, and the *Petroleum Taxes Act* (1974) (the "**Petroleum Taxes Act**"). The Petroleum Act establishes a framework for the grant of licences and contracts and for the conduct of petroleum operations including activity on land and in submarine areas underlying the country's territorial waters. Under the Petroleum Act, the MEEI is responsible for determining the areas to be made available for petroleum operations and may elect to invite applications for the rights to explore for and produce petroleum from these areas, via competitive bidding. Persons wishing to engage in petroleum exploration and production operations must apply to the MEEI. On the basis of the Petroleum Act and its subsidiary regulations, the MEEI regulates and gives broad direction and guidance to the petroleum industry. The Petroleum Taxes Act is administered by the Minister of Finance through the Board of Inland Revenue and establishes the system of taxation for companies engaged in petroleum operations.

Private participation in the oil and natural gas industry in Trinidad & Tobago is undertaken under one of two fiscal regimes: exploration and production licences (otherwise known as royalty/tax concessions) and production sharing contracts. Both are currently in operation. The current licensing regime does not provide for compulsory state participation. However, Petrotrin and the National Gas Company have taken equity shares in some projects.

Market Conditions

Trinidad & Tobago's main oil pipeline network is focused on moving liquids from the fields in the Columbus Sub-basin, offshore Trinidad's east coast, to oil processing facilities at Galeota Point. After processing, the crude is piped via a 42-inch pipeline to dedicated tanker loading facilities. A smaller network carries crude produced off the south west coast to shore at Point Fortin. From there, the crude is piped via Petrotrin's onshore pipeline network to the Petrotrin refinery at Pointe-a-Pierre.

Following the closure of the Point Fortin refinery in the 1990s, Trinidad & Tobago now has only one oil refinery, located at Pointe-a-Pierre in Trinidad. This facility manufactures oil products both for domestic use and for export. The plant is operated by Petrotrin. The refinery has recently been upgraded to a capacity of 175,000 barrels per day.

Colombia

Economic

According to the Economic Intelligence Unit Country Forecast (February 2011), GDP growth in Colombia was 3.9 percent in 2010 and expected to increase to 4.5 percent in 2011. Colombian inflation is expected to average 3.7% in 2011-15. Exports are estimated to have grown by 2.7% in 2010, and is forecast to rebound more strongly in 2011-15, driven by various factors, including robust oil and mining production growth, the resumption of trade with

Venezuela and a boost from free trade agreements with Canada, the US, and the EU, which we expect to be implemented in 2011-12. The Colombian peso appreciated in 2010, but it is expected that global uncertainty will keep the peso at an average of Ps1,867: $1 in 2011-15, compared with Ps1,899: $1 in 2010.

Royalties

In 2004, the ANH released new fiscal terms based on a royalty/tax system, abolishing the incumbent association contract model. The most fundamental change to the terms is that Ecopetrol, the national oil company, has no mandatory back-in right. The contractor owns rights to all production net of royalty.

Royalty payments vary depending on the quality of oil and the rate of production and are applied on a field-by-field basis. For light/medium oil, the stated royalty rate is as presented in the following table:

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

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

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

High Price Participation

For contracts signed under the new ANH oil regulatory regime, in 2004 and onwards, a high price share of production applies once a field has cumulatively produced more than 5 mmbbls of oil, determined before the deduction of royalties. For the Company's ANH contracts, the share of production to be paid is based on the established percent (S) of the part of the average monthly reference WTI price (P) that exceeds a base price (Po), divided by the average monthly reference price (P).

Quality	Base Price (Po) 2010 Threshold Prices
Less than 10º API	Nil
10º to 15º API	$49.73/bbl
15º to 22º API	$34.61/bbl
22º to 29º API	$33.37/bbl
Greater than 29º API	$32.13/bbl

Average Monthly Reference WTI Price (P)	Established Percentage (S)
Po ≤ P ≤ 2Po	30%
2Po ≤ P ≤ 3Po	35%
3Po ≤ P ≤ 4Po	40%
4Po ≤ P ≤ 5Po	45%
5Po ≤ P	50%

Crude oil production with a quality above 29º API and a realized oil price of $75/bbl results in a production share equivalent to an incremental 20 percent royalty, bringing the total government take to 29 percent for a field with production less than 10,000 bbl/d. Threshold prices are adjusted annually.

Corporations are subject to a 33 percent tax on net income or a presumptive minimum tax of 3 percent of net equity, whichever is the greater. Income tax losses can be carried forward indefinitely. Unsuccessful exploration costs can be written off in the current year or in any of the following two years. Other exploration and development costs are amortized using either a straight-line or units-of-production method, but in no case may be amortized over a period of less than five years. Qualifying assets purchased or constructed to be used directly in income-producing activities are eligible for an extra tax deduction equal to 30 percent of the original cost. The amount of the 30 percent incentive is tax-deductible immediately. Recapture provisions apply to the incentive to the extent the asset ceases to be used in the income-producing activities or is sold.

Regulatory Regime

The regulatory regime in Colombia underwent a significant change, effective January 1, 2004, with the formation of the ANH, which has assumed the role of regulating the Colombian oil industry. This function was previously performed by Ecopetrol.

The ANH developed a new exploration risk contract that took effect near the end of the first quarter of 2005. This contract has significantly 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 new agreement provides full risk/reward benefits for the contractor. Under the terms of the contract the successful operator will retain 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 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 exploration phase which lasts six years and comprises an initial phase 1 lasting 3 years and an option phase 2 which is also 3 years. The exploration phase can be extended for up to an additional four years under certain circumstances; (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 natural 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 5 percent for natural gas to 10 percent for oil of the remaining reserves value.

Relinquishment of part or all the licence 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 licence 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.

Environmental Regulation

The environmental regulatory framework in Colombia which governs the oil and natural gas industry is divided into two parts: planning and compliance.

Planning

The Colombian Ministry of Environment, Housing and Territorial Development ("**MADVT**") requires that environmental impact assessments ("**EIA**") and environmental management plans ("**EMP**") be submitted as the principal planning tools for all new projects, ensuring local and specific environmental and social variables are included in project planning. Following approval of the EIA, the MADVT awards an environmental licence. When a discovery is made, the environmental licence typically allows for a maximum one year of production testing, while the company prepares a new EIA and EMP for the development of a permanent oil and natural gas production field and development drilling.

Field pipeline design and construction is subject to a two part environmental licensing process. First, an environmental options assessment ("**EOA**") is conducted, whereby both the company and the government environmental authority review options to agree on an environmentally friendly pipeline design and layout. Once an agreement is reached, the company can apply for the pipeline environmental licence through a comprehensive EIA and EMP.

Once a production field's environmental licence is in place, development drilling, flowlines, batteries and other production infrastructure can be added by preparing specific EMPs.

Compliance

In Colombia, regulations relating to compliance standards include specific standards for water and air quality, wastewater and solid waste treatment and disposal, air emission control and industrial hygiene. In addition, the environmental licence normally includes obligations which have to be compiled with by the operator.

Market Conditions

Colombia has a well-developed oil infrastructure system, comprising over 6,000 kilometres of crude and product pipelines. The system is concentrated on transporting crude from the main producing basins (Llanos and the Magdalenas), via a central hub at Vasconia in the interior, to Colombia's main oil export terminal at Coveñas on the Caribbean coast. Additionally, a key line runs separately from the Caño Limón field near the Venezuelan border to Coveñas. In the far south, the Oleoducto Trans-Andino carries crude to the Pacific port of Tumaco. With the expansion of the Llanos basin, production is becoming constrained for heavier crude.

Colombia currently operates five refineries, all of which are owned by Ecopetrol. Two of these, Barrancabermeja and Cartagena, are main fuels refineries, accounting for almost all of the country's refining capacity. The remaining three refineries are small and simple. Total crude processing capacity is roughly 290,000 bbls/d and is effectively close to being fully loaded, with a utilisation rate over 90 percent. In 2000, Ecopetrol announced plans to invest up to $1.1 billion in improving the efficiency of the Barrancabermeja and Cartagena refineries. However, the refinery expansion projects have suffered increasing delays due to government concerns.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Parex. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. **Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.**

In assessing the risks of an investment in the Common Shares, potential investors should realize that they are relying on the experience, judgment, discretion, integrity and good faith of the management of Parex. **An investment in Common Shares is suitable for only those investors who are willing to risk a loss of their entire investment and who can afford to lose their entire investment. Subscribers should consult their own professional advisors to assess the income tax, legal and other aspects of an investment in the Common Shares.**

Trinidad & Tobago

Parex Trinidad has entered into the PSCs under which it has committed to spend an estimated $18 million over four years for onshore oil and natural gas exploration. The Company entered into the Moruga Farm-In and has committed to spend up to $13.3 million by drilling two wells onshore. Therefore Parex will be subject to additional risks associated with international operations in Trinidad & Tobago.

Trinidad & Tobago has experienced relative prosperity and stability. Oil and natural gas resources and economic growth were part of the issues debated by the two main parties in the political arena. Future political stalemates could lead to indecision and inertia in the oil and natural gas regulatory arena which could adversely affect any oil and natural gas operations being carried out by the Company. As a result of limited infrastructure present in Trinidad & Tobago, land titles systems are not developed to the extent found in many more developed nations.

Colombia

Parex Colombia owns a 50 percent working interest in four exploration blocks. The contracts consist of an initial exploration phase of three years with the option for the parties to enter a second three-year exploration phase beyond the initial phase. Parex Colombia's net capital commitment for the initial exploration phase is approximately $46 million. Therefore Parex will be subject to additional risks associated with international operations in Colombia.

Guerrilla Activity in Colombia

A 40-year armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups, both thought to be funded by the drug trade, continues in Colombia. Insurgents continue to attack civilians and violent guerrilla activity continues in many parts of the country. The Putumayo region has been prone to guerrilla activity in the past. Pipelines have also been targets, including the Trans-Andean export pipeline which transports oil from the Putumayo region. In March and April of 2008, sections of one of the Ecopetrol pipelines were blown up by guerrillas. Ecopetrol was able to restore deliveries within one to two weeks of these attacks. The Catatumbo basin borders Venezuela and has historically been an area of high security risk where there continues to be guerrilla activity. Parex Colombia does not currently have interest in either the Putumayo region or Catatumbo basin. At present, the Company only has operations in the Llanos basin.

Continuing attempts to reduce or prevent guerrilla activity may not be successful and guerrilla activity may disrupt Parex Colombia's operations in the future. Parex Colombia may not be able to establish or maintain the safety of its operations and personnel in Colombia and this violence may affect its operations in the future. Continued or heightened security concerns in Colombia could also result in a significant loss to Parex Colombia and/or costs exceeding current expectations.

United States Relations with Colombia

Colombia is among several nations whose progress in stemming the production and transit of illegal drugs is subject to annual certification by the President of the United States of America. Although Colombia has received a current certification, there can be no assurance that, in the future, Colombia will receive certification or a national interest waiver. The failure to receive certification or a national interest waiver may result in any of the following:

- all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended;
- the Export-Import Bank of the United States and the Overseas Private Investment Company would not approve financing for new projects in Colombia;
- United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes, and
- the President of the United States and Congress would retain the right to apply future trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with operations there. Any changes in the holders of significant government offices could have adverse consequences on Parex Colombia's relationship with the ANH and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to Parex Colombia's foreign operations. Any sanctions imposed on Colombia by the United States government could threaten Parex Colombia's ability to obtain any necessary financing to develop the Colombian properties. There can be no assurance that the United States will not impose sanctions on Colombia in the future, nor can the effect in Colombia that these sanctions might cause be predicted.

General

Stage of Development

There are additional risks associated with an investment in Parex related to the early stage of Parex' development. These risks include, but are not limited to, availability of subsequent financing, complications and delays in establishment of operations in new jurisdictions, control of expenses, the ability to establish profitable operations and other difficulties.

Additional Financing

Depending on future exploration, development, acquisition and divestiture plans, Parex may require additional financing. The ability of Parex to arrange any such financing in the future will depend in part upon the prevailing capital market conditions, risk associated with the international operations, as well as the business performance of Parex. Periodic fluctuations in energy prices may affect lending policies for potential future lenders. This in turn could limit growth prospects in the short run or may even require Parex to dedicate existing cash balances or cash flow, dispose of properties or raise new equity to continue operations under circumstances of declining energy prices, disappointing drilling results, or economic or political dislocation in foreign countries. There can be no assurance that Parex will be successful in its efforts to arrange additional financing on terms satisfactory to Parex. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. If additional financing is raised by the issuance of shares from treasury of Parex, control of Parex may change and shareholders may suffer additional dilution.

Conditions in the Oil and Natural Gas Industry

The oil and natural gas industry is intensely competitive and Parex will compete with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on an international basis.

The impact on the oil and natural gas industry from commodity price volatility is significant. During periods of high prices, producers may generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers may also decline.

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration or development activities by Parex will result in discoveries of oil or natural gas that are commercially or economically feasible. It is difficult to project the costs of implementing any exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Parex' operations will be subject to all the risks normally associated with the exploration, development and operation of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, potential environmental damage, blow-outs, cratering, fires and spills, all of which could result in personal injuries, loss of life and damage to property of Parex and others. In accordance with customary industry practice Parex will maintain insurance coverage, but will not be fully insured against all risks, nor are all such risks insurable.

Oil and natural gas exploration and development activities are dependent on the availability of seismic, drilling and other specialized equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Parex and may delay exploration and development activities.

Exploration, Development and Production Risks

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

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

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

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices.

These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

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

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Environmental Regulation and Risks

Extensive national, provincial and local environmental laws and regulations in Colombia and Trinidad & Tobago will affect nearly all of the operations of Parex. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that Parex will not incur substantial financial obligations in connection with environmental compliance.

Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Significant liability could be imposed on Parex for damages, clean-up costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of properties purchased by Parex or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on Parex. Moreover, Parex cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by Parex for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on Parex.

Reserve Estimates

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

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

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

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

Reliance on Third Party Operators and Key Personnel

To the extent that the Company is not the operator of its properties, the Company 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.

Natural Disasters and Weather-Related Risks

Parex will be subject to operating hazards normally associated with the exploration and production of oil and natural gas, including blowouts, explosions, oil spills, cratering, pollution, earthquakes, hurricanes and fires. The occurrence of any such operating hazards could result in substantial losses to Parex due to injury or loss of life and damage to or destruction of oil and natural gas wells, formations, production facilities or other properties.

The majority of oil in Colombia is delivered by a single pipeline to Ecopetrol and sales of oil could be disrupted by damage to this pipeline. Once delivered to Ecopetrol, oil production in Colombia is transported by an export pipeline which provides the only access to markets for oil. Without other transportation alternatives, sales of oil could be disrupted by landslides or other natural events which impact this pipeline.

Foreign Subsidiaries

Parex will conduct all of its operations in Trinidad & Tobago and Colombia through foreign subsidiaries and a foreign branch. Therefore, to the extent of these holdings, Parex will be dependent on the cash flows of these subsidiaries to meet its obligations excluding any additional equity Parex may issue from time to time. The ability of its subsidiaries to make payments to Parex may be constrained by among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdiction in which it operates; and the introduction of foreign exchange and/or currency controls or repatriation restrictions or the availability of hard currency to be repatriated.

Risks of Foreign Operations

Parex' operations may be adversely affected by changes in foreign government policies and legislation or social instability and other factors which are not within the control of Parex, including, but not limited to, nationalization, expropriation of property without fair compensation, renegotiation or nullification of existing concessions and contracts, the imposition of specific drilling obligations and the development and abandonment of fields, changes in energy policies or the personnel administering them, changes in oil and natural gas pricing policies, the actions of national labour unions, currency fluctuations and devaluations, exchange controls, economic sanctions and royalty and tax increases and other risks arising out of foreign governmental sovereignty over the areas in which Parex' operations will be conducted, as well as risks of loss due to civil strife, acts of war, terrorism, guerrilla activities and insurrections. Parex' operations may also be adversely affected by laws and policies of Trinidad & Tobago and Colombia affecting foreign trade, taxation and investment. If Parex' operations are disrupted and/or the economic integrity of its projects is threatened for unexpected reasons, its business may be harmed. Prolonged problems may threaten the commercial viability of its operations.

In the event of a dispute arising in connection with Parex' operations in Trinidad & Tobago or Colombia, Parex may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgements in such other jurisdictions. Parex may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, Parex' exploration, development and production activities in Trinidad & Tobago and Colombia could be substantially affected by factors beyond Parex' control, any of which could have a material adverse effect on Parex.

Acquiring interests and conducting exploration and development operations in foreign jurisdictions often require compliance with numerous and extensive procedures and formalities. These procedures and formalities may result in unexpected or lengthy delays in commencing important business activities. In some cases, failure to follow such formalities or obtain relevant evidence may call into question the validity of the entity or the actions taken. Management is unable to predict the effect of additional corporate and regulatory formalities which may be adopted in the future including whether any such laws or regulations would materially increase Parex' cost of doing business or affect its operations in any area.

Parex may in the future acquire oil and natural gas properties and operations outside of Trinidad & Tobago and Colombia, which expansion may present challenges and risks that Parex has not faced in the past, any of which could adversely affect the results of operations and/or financial condition of Parex.

Security and Insurance

Colombia has a publicized history of security problems. The Company and its personnel are subject to these risks, but through effective security and social programs, Parex believes these risks can be effectively managed. The Company maintains insurance in an amount that it considers adequate and consistent with industry practice and its operations, however, 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.

Legal Systems

Colombia is a civil law jurisdictions. Trinidad & Tobago, being part of the Commonwealth, has a similar legal system to Canada. There can be no assurance that joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by changes in governments, the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

Potential Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Company will be subject in connection with the operations of the Company. Some of the directors and officers are engaged and will continue to be engaged in the search for oil and natural gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an 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, to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular for the Company's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Company's consolidated financial statements and the related management's discussion and analysis for the Company's most recently completed financial year.

SCHEDULE "A"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Parex Resources Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Operations and 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 evaluator;

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

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Operations and Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The board of directors has 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 51-102F2 which is the report of the independent qualified reserves evaluator 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.

(signed) "*Wayne Foo*"
Wayne Foo
President and Chief Executive Officer

(signed) "*Kenneth Pinsky*"
Kenneth Pinsky
Vice President Finance and Chief Financial Officer

(signed) "*Norman McIntyre*"
Norman McIntyre
Chairman

(signed) "*John Bechtold*"
John Bechtold
Chairman of Operations and Reserves Committee

DATED as of this 9th day of March, 2011.

SCHEDULE "B"

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

To the board of directors of Parex Resources Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves ,probable reserves, and proved plus probable plus possible reserves and related future net revenue as at December 31, 2010, 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, 2010, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			M$	M$	M$	M$
GLJ Petroleum Consultants Ltd.	January 31, 2011	Colombia	-	206,361	-	206,361

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. 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 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.

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, dated March 9, 2011.

GLJ Petroleum Consultants Ltd.

Per: (signed) "*Keith M. Braaten*"
Keith M. Braaten, P. Eng..

SCHEDULE "C"

FINANCE AND AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

1. Overall Purpose & Objectives

A standing committee of the Board of Directors of Parex Resources Inc. (the "Corporation") consisting of members of the Board is hereby appointed by the Board from amongst its members and complying with all other legislation, regulations, agreements, articles and policies to which the Corporation and its business is subject is hereby established and designated the Audit Committee (hereinafter referred to as the "Audit Committee").

The Audit Committee will assist the Board in fulfilling its oversight responsibilities, including without limitation the review, approval or recommendation to the Board for approval, of:

- the Corporation's financial statements, and the integrity of the financial reporting process,
- the management of financial and other enterprise risks,
- the external audit process and the Corporation's process for monitoring compliance with financial laws and regulations,
- any material disclosure of information to shareholders, security regulators and the public; and
- significant acquisitions and divestitures.

The Committee shall also take the steps necessary to address and resolve all instances or allegations of fraud reported to the Committee.

2. Composition

(a) This Committee shall be composed of at least three individuals appointed by the Board from amongst its members. The Committee shall appoint one member as Committee Chair. All members of the Committee shall be Board members who are not executive officers of the Corporation.

(b) A quorum shall be a majority of the members of the Committee.

(c) Members should all be financially literate, as defined in Multilateral Instrument 52-110 Audit Committees as adopted by the Canadian Securities Regulatory Authorities ("MI 52-110"), and at least one member must have accounting or related financial management expertise.

(d) A majority of Committee members should be free from any direct or indirect material relationship, as defined in MI 52-110, with the Corporation that could impair the exercise of independent judgment.

3. Meetings

(a) The Audit Committee shall meet at least quarterly with Management, and at least annually with the external auditors, such meetings generally coinciding with the release of interim or year-end financial information.

(b) Effective agendas, with input from Management, shall be circulated to Committee members and relevant Management personnel along with background information on a timely basis prior to the Committee meetings.

(c) Minutes of each meeting shall be prepared.

(d) The meetings and proceedings of the Audit Committee shall be governed by the provisions of the by-laws of the Corporation that regulate meetings and proceedings of the Board.

(e) The Audit Committee may invite the Chief Executive Officer or his designate(s), such Directors, Officers or employees of the Corporation, the Corporation's external auditor(s) and any other independent external advisors or consultants as it may see fit to attend its meetings and take part in the discussion and consideration of the affairs of the Audit Committee.

4. Reporting / Authority

(a) Following each meeting, the Committee will report to the Board and provide a summary of the meeting.

(b) Copies of the minutes from all meetings, as well as information and supporting schedules reviewed and discussed by the Audit Committee at any meeting shall be retained and made available for examination by the Board or any Director upon request to the Chair.

(c) The Committee shall have the authority to investigate any activity of the Corporation falling within the terms of this Mandate, and may request any employee of the Corporation to cooperate with any request made by the Committee.

(d) The Committee may retain external persons having special expertise and obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation and approve the terms of retainer and the fees payable to such parties.

5. Duties & Responsibilities

(a) Financial Information and Shareholder Communication

Review:

(i) The audited annual financial statements and unaudited quarterly financial statements with Management and the external auditors (including disclosures under "Management's Discussion & Analysis"), in conjunction with the report of the external auditors, and obtain explanation from Management of all material variances between comparative reporting periods. Upon satisfactory completion of the review, the Committee will recommend that the Board of Directors approve the annual and quarterly financial statements.

(ii) Shareholder communications based on the quarterly and annual financial statements.

(iii) Significant accounting and tax compliance issues where there is choice among various alternatives or where application of a policy has a material effect on the financial results of the Corporation.

(b) Internal Controls

Review annually and approve as required:

(i) Processes adopted by Management for establishing effective internal controls, to be responsible for the accurate reporting of the company's revenues and expenses, and the safeguarding of its assets.

(ii) Internal control systems maintained by the Corporation.

(iii) Major changes to management information systems.

(iv) Spending authority and approval of limits.

(c) Enterprise Risk Management

Review periodically the Corporation's:

(i) Risk assessment and risk management policies.

(ii) Hedging strategies, policies, objectives and controls.

(iii) Risk retention philosophy and resulting exposure to the Corporation.

(iv) Loss prevention policies and programs in the context of competitive and operational consideration.

(v) Insurance programs.

(vi) Directors' and Officers' insurance coverage.

(vii) Procedures for the control, identification and reporting of fraudulent acts.

(d) External Auditors

(i) Annually:

(A) Recommend to the Board of Directors an independent accounting firm to conduct the annual audit.

(B) Review with Management and auditors the purpose and scope of the audit examination, review the terms of the external auditors' engagement and set the fees for the annual audit.

(C) Assess the qualifications, performance and independence of the auditors, taking into account the opinions of Management, and present conclusions to the Board.

(D) Obtain and review a report by the external auditors describing: the firm's internal quality control procedures; any material issues raised by the most recent internal quality control review (or peer review) of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm and any steps taken to deal with such issues.

(E) Obtain a certificate attesting to the external auditors' independence, which identifies all relationships between the external auditors and the Corporation.

(F) Review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Instrument 51-102 as adopted by the Canadian Securities Regulatory Authorities ("NI 51-102"), on a routine basis, whether or not there is a change of auditors.

(G) Meet independently with auditors in the absence of Management to discuss any issues which the auditors may wish to bring forward including any restrictions imposed by Management or significant accounting issues in which there was a disagreement with Management.

(ii) Where there is a change of auditor, review all issues related to the change, including information to be included in the notice of change of auditors (NI 51-102), and the planned steps for an orderly transition.

(iii) Pre-approve engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

(e) Audit

(i) Review with Management and the external auditors major issues regarding accounting principles and financial statement presentation, including any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of Management that may be material to financial reporting.

(ii) Question Management and the external auditors regarding significant financial reporting issues during the fiscal period and the method of resolution of such issues.

(iii) Monitor the steps taken by management to deal with issues arising from the annual audit.

(iv) Review the auditors' report to Management, containing recommendations of the external auditors', and Management's response and subsequent remedy of any identified weaknesses.

(v) Prepare an Audit Committee report as may be required by the relevant Securities and Exchange Commission to be included in the Corporation's annual Management Proxy Circular.

(f) Press

Review of press releases and other publicly circulated documents containing financial information or financial guidance.

(g) Legal

Review annually the legal expenses incurred by the Corporation.

(h) Budget and Forecast of Operations

(i) Be responsible for the Corporation having in place a process to review all general and administrative expenditures to improve future planning and cost control.

(ii) Be responsible for the Corporation having in place a process to review all material capital investments to assess where value has been created and improve future decisions.

(i) New Business Development

Review of proposed acquisitions and divestitures at the request of the Board, including a review of the financial and legal due diligence conducted, and make recommendations to the Board as to the completion of such transactions.

(j) Audit Committee Evaluation and Complaints

Periodically, in conjunction with the Corporate Governance Committee:

(i) Assess individual Audit Committee member and Chair performance and evaluate the performance of the Audit Committee as a whole, including its processes and effectiveness.

(ii) Review the Corporation's procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters.

(iii) Review the Corporation's procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

(iv) Develop and approve Audit Committee member eligibility criteria, identify Directors qualified to become Committee members and recommend appointments to and removals from the Audit Committee.

6. Other Duties & Responsibilities

(a) The Audit Committee shall be available to meet with any member of Management or any employee of the Corporation who wishes to raise any concern with respect to conflicts of interest and ethical issues.

(b) The responsibilities, practices and duties of the Audit Committee outlined herein are not intended to be comprehensive. The Board may, from time to time, charge the Audit Committee with the responsibility of reviewing items of a financial, control or risk management nature