

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2012

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission file number 001-34018

GRAN TIERRA ENERGY INC.

(Exact name of registrant as specified in its charter)

Nevada

(State or other jurisdiction of incorporation or organization)

98-0479924

(I.R.S. Employer Identification No.)

**300, 625 11 Avenue S.W.
Calgary, Alberta, Canada T2R 0E1**

(Address of principal executive offices, including zip code)

(403) 265-3221

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value \$0.001 per share	NYSE MKT Toronto Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Accelerated filer

Non-accelerated filer (do not check if a smaller reporting company)

Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second fiscal quarter was approximately \$1.3 billion (including shares issuable upon exercise of exchangeable shares). Aggregate market value excludes an aggregate of 1,267,207 shares of Common Stock and 9,348,650 shares issuable upon exercise of exchangeable shares held by officers and directors on such date. Exclusion of shares held by any of these persons should not be construed to indicate that such person possesses the power, direct or indirect, to direct or cause the direction of the management or policies of the registrant, or that such person is controlled by or under common control with the registrant.

On February 20, 2013, the following numbers of shares of the registrant's capital stock were outstanding: 268,621,445 shares of the registrant's Common Stock, \$0.001 par value; one share of Special A Voting Stock, \$0.001 par value, representing 6,223,810 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, \$0.001 par value, representing 7,058,678 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this report, to the extent not set forth herein, is incorporated by reference from the registrant's definitive proxy statement relating to the 2013 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2012.

Gran Tierra Energy Inc.

Annual Report on Form 10-K

Year Ended December 31, 2012

Table of contents

	Page
PART I	
Item 1. Business	7
Item 1A. Risk Factors	37
Item 1B. Unresolved Staff Comments	52
Item 2. Properties	52
Item 3. Legal Proceedings	52
Item 4. Mine Safety Disclosures	52
PART II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	55
Item 6. Selected Financial Data	57
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	58
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	87
Item 8. Financial Statements and Supplementary Data	88
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	119
Item 9A. Controls and Procedures	120
Item 9B. Other Information	122
PART III	
Item 10. Directors, Executive Officers and Corporate Governance	122
Item 11. Executive Compensation	122
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	122
Item 13. Certain Relationships and Related Transactions, and Director Independence	123
Item 14. Principal Accounting Fees and Services	123
PART IV	
Item 15. Exhibits and Financial Statement Schedules	123
SIGNATURES	124
EXHIBIT INDEX	126

STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K, particularly in Item 1. "Business" and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Annual Report on Form 10-K, including without limitation statements in the Management's Discussion and Analysis of Financial Condition and Results of Operations, regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words "believe", "expect", "anticipate", "intend", "estimate", "project", "target", "goal", "plan", "objective", "should", or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part I, Item 1A "Risk Factors" in this Annual Report on Form 10-K. The information included herein is given as of the filing date of this Form 10-K with the Securities and Exchange Commission ("SEC") and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Annual Report on Form 10-K to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
BOE	barrels of oil equivalent	MMBtu	million British thermal units
MMBOE	million barrels of oil equivalent	NGL	natural gas liquids
BOEPD	barrels of oil equivalent per day	NAR	net after royalty
BOPD	barrels of oil per day		

NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices.

In the discussion that follows we discuss our interests in wells and/or acres in gross and net terms. Gross oil and natural gas wells or acres refer to the total number of wells or acres in which we own a working interest. Net oil and natural gas wells or acres are determined by multiplying gross wells or acres by the working interest that we own in such wells or acres. Working interest refers to the interest we own in a property, which entitles us to receive a specified percentage of the proceeds of the sale of oil and natural gas, and also requires us to bear a specified percentage of the cost to explore for, develop and produce that oil and natural gas. A working interest owner that owns a portion of the working interest may participate either as operator, or by voting its percentage interest to approve or disapprove the appointment of an operator, in drilling and other major activities in connection with the development of a property.

We also refer to royalties and farm-in or farm-out transactions. Royalties include payments to governments on the production of oil and gas, either in kind or in cash. Royalties also include overriding royalties paid to third parties. Our reserves, production volumes and sales are reported net after deduction of royalties. Production volumes are also reported net of inventory adjustments. Farm-in or farm-out transactions refer to transactions in which a portion of a working interest is sold by an owner of an oil and gas property. The transaction is labeled a farm-in by the purchaser of the working interest and a farm-out by the seller of the working interest. Payment in a farm-in or farm-out transaction can be in cash or in kind by committing to perform and/or pay for certain work obligations.

In the petroleum industry, geologic settings with proven petroleum source rocks, migration pathways, reservoir rocks and traps are referred to as petroleum systems.

Several items that relate to oil and gas operations, including aeromagnetic and aerogravity surveys, seismic operations and several kinds of drilling and other well operations, are also discussed in this document.

Aeromagnetic and aerogravity surveys are a remote sensing process by which data is gathered about the subsurface of the earth. An airplane is equipped with extremely sensitive instruments that measure changes in the earth's gravitational and magnetic field. Variations as small as 1/1,000th in the gravitational and magnetic field strength and direction can indicate structural changes below the ground surface. These structural changes may influence the trapping of hydrocarbons. These surveys are an efficient way of gathering data over large regions.

Seismic data is used by oil and natural gas companies as the principal source of information to locate oil and natural gas deposits, both for exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computer software applications are then used to process the raw data to develop an image of underground formations. 2-D seismic is the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data. 3-D seismic data is collected using a grid of energy sources, which are generally spread over several square miles. A 3-D seismic survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Wells drilled are classified as exploration, development, injector or stratigraphic. An exploration well is a well drilled in search of a previously undiscovered hydrocarbon-bearing reservoir. A development well is a well drilled to develop a hydrocarbon-bearing reservoir that is already discovered. Exploration and development wells are tested during and after the drilling process to determine if they have oil or natural gas that can be produced economically in commercial quantities. If they do, the well will be completed for production, which could involve a variety of equipment, the specifics of which depend on a number of technical geological and engineering considerations. If there is no oil or natural gas (a "dry" well), or there is oil and natural gas but the quantities are too small and/or too difficult to produce, the well will be abandoned. Abandonment is a completion operation that involves closing or "plugging" the well and remediating the drilling site. An injector well is a development well that will be used to inject fluid into a reservoir to increase production from other wells. A stratigraphic well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. These wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if drilled in an unknown area or "development type" if drilled in a known area.

Workover is a term used to describe remedial operations on a previously completed well to clean, repair and/or maintain the well for the purpose of increasing or restoring production. It could include well deepening, plugging portions of the well, working with cementing, scale removal, acidizing, fracture stimulation, changing tubulars or installing/changing equipment to provide artificial lift.

The SEC definitions related to oil and natural gas reserves, per Regulation S-X, reflecting our use of deterministic reserve estimation methods, are as follows:

- *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

- *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
 - i. The area of the reservoir considered as proved includes:
 - A. The area identified by drilling and limited by fluid contacts, if any, and
 - B. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
 - ii. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
 - iii. Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
 - iv. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
 - A. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
 - B. The project has been approved for development by all necessary parties and entities, including governmental entities.
 - v. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
- *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
 - i. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
 - ii. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

- iii. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
 - iv. See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of section 210.4-10(a) of Regulations S-X.
- *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
 - i. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
 - ii. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
 - iii. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
 - iv. The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
 - v. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
 - vi. Pursuant to paragraph (a)(22)(iii) of section 210.4-10(a) of Regulations S-X, where direct observation has defined a HKO elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.
 - *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.
 - *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.
 - *Probabilistic estimate.* The method of estimating reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience, engineering or economic data) is used to generate a full range of possible outcomes and their associated probabilities of occurrences.

- *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:
 - i. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; and
 - ii. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
- *Undeveloped oil and gas reserves*. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
 - i. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
 - ii. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
 - iii. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of section 201.4-10(a) of Regulation S-X, or by other evidence using reliable technology establishing reasonable certainty.

PART I

Item 1. *Business*

General

Gran Tierra Energy Inc. together with its subsidiaries (“Gran Tierra”, “us”, “our”, or “we”) is an independent international energy company engaged in oil and gas acquisition, exploration, development and production. We own oil and gas properties in Colombia, Argentina, Peru and Brazil.

Our principal executive offices are located at 300, 625-11th Avenue S.W., Calgary, Alberta, Canada. The telephone number at our principal executive office is (403) 265-3221. All dollar (\$) amounts referred to in this Annual Report on Form 10-K are United States (U.S.) dollars, unless otherwise indicated.

Development of Our Business

Our company was incorporated under the laws of the State of Nevada on June 6, 2003, originally under the name Goldstrike Inc. We made our initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005. Since then, we have acquired oil and gas producing and non-producing assets in Colombia, Peru, Argentina and Brazil, with our largest acquisitions being the acquisition of Solana Resources Limited (“Solana”) in 2008 and Petrolifera Petroleum Limited (“Petrolifera”) in 2011.

In 2012:

- in Colombia, we added two blocks through the 2012 Colombia Bid Round and continued to focus on developing our producing fields, including Costayaco and Moqueta, and on the generation of exploration prospects;
- in Brazil, we acquired the remaining 30% working interest in our Recôncavo Basin Blocks, received declaration of commerciality for the Tiê field and received regulatory approval for the farm-out of Block BM-CAL-7 in the offshore Camamu Basin;
- in Peru, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block and operatorship to us and we entered into an agreement to acquire the remaining 40% working interest in this block; we commenced drilling an exploration well on Block 95; and, in Blocks 123 and 129, increased our working interest from 20% to 100%, subject to regulatory approval, and, subsequent to year end, assumed operatorship;

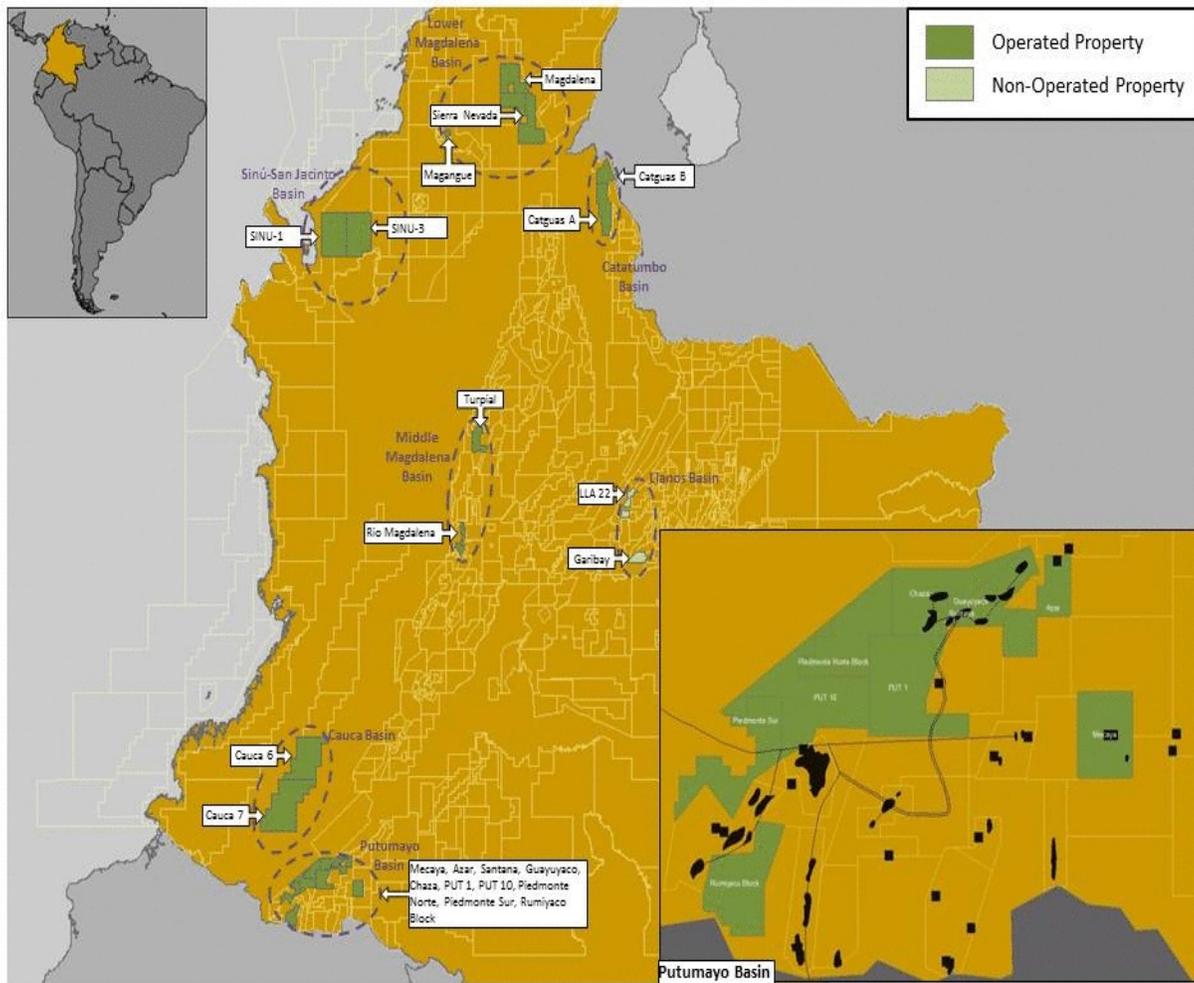
- in Argentina, we continued to focus on developing our producing fields, including the Surubi, Puesto Morales and Rinconada Norte fields.

In the year ended December 31, 2012, we incurred capital expenditures of \$349.8 million (excluding changes in non-cash working capital and including the \$36.6 million acquisition in Brazil and net of proceeds from disposition of oil and gas properties), including acquisitions of \$49.1 million, drilling expenditures of \$218.1 million, facilities expenses of \$17.9 million, geological and geophysical ("G&G") expenses of \$48.0 million and other expenditures of \$16.7 million.

Our acreage as of December 31, 2012, including acquisitions and excluding farm-outs and relinquishments which were subject to various government approvals, included:

- 4.5 million gross acres in Colombia (3.7 million net) covering 23 exploration and production contracts, six of which were producing and 21 of which were operated by Gran Tierra (excludes four blocks or 277,072 gross and 210,692 net acres for which working interest changes were subject to approval);
- 1.3 million gross acres (0.6 million net) in Argentina covering 11 exploration and production contracts, eight of which were producing and nine of which were operated by Gran Tierra;
- 6.4 million gross acres (6.4 million net) in Peru covering five exploration licenses, all of which were frontier exploration areas and three of which were operated by Gran Tierra (includes three blocks or 3.3 million net acres which were subject to government approval). Subsequent to year end, we assumed operatorship of the two remaining blocks in Peru; and
- 0.4 million gross acres (61 thousand net) in Brazil covering five exploration blocks, one of which was producing and four of which were operated by Gran Tierra.

Oil and Gas Properties – Colombia



We have interests in 23 blocks in Colombia, and are the operator in 21 blocks. The Chaza, Guayuyaco, Garibay, and Santana Blocks have producing oil wells. The Magangué and Sierra Nevada Blocks each have one producing gas well. During the year ended December 31, 2012, 66% of our consolidated production, NAR adjusted for inventory changes, was from the Chaza Block.

In 2012, we were awarded two exploration blocks, Sinu-1 and Sinu-3 in the Sinu Basin, in the 2012 Colombia Bid Round.

Royalties

Colombian royalties are established under law 756 of 2002. All discoveries made subsequent to the enactment of this law have the sliding scale royalty described below. Discoveries made before the enactment of this law have a royalty of 20%. The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") contracts to which Gran Tierra is a party all have royalties that are based on a sliding scale described in law 756. This royalty works on an individual oil field basis starting with a base royalty rate of 8% for gross production of less than 5,000 BOPD. The royalty increases in a linear fashion from 8% to 20% for gross production between 5,000 and 125,000 BOPD, and is stable at 20% for gross production between 125,000 and 400,000 BOPD. For gross production between 400,000 and 600,000 BOPD the rate increases in a linear fashion from 20% to 25%. For gross production in excess of 600,000 BOPD the royalty rate is fixed at 25%. The Llanos-22 Block has an additional royalty of 1%.

For gas fields, the royalty is on an individual gas field basis starting with a base royalty rate of 6.4% for gross production of less than 28.5 MMcf of gas per day. The royalty increases in a linear fashion from 6.4% to 20% for gross production between 28.5 MMcf of gas per day and 3.42 Bcf of gas per day, and is stable at 16% for gross production between 712.5 to 2,280 MMcf of gas per day. For gross production between 2.28 to 3.42 Bcf of gas per day the rate increases in a linear fashion from 16% to 20%. For gross production in excess of 3.42 Bcf of gas per day the royalty rate is fixed at 20%.

Our production from the Costayaco field is also subject to an additional royalty (the "HPR royalty") that applies when cumulative gross production from a commercial field is greater than five MMbbl. This additional royalty is calculated on the difference between a trigger price defined by the ANH and the sales price. As the Chaza Block exploration and production contract (the "Chaza Contract") stands currently, any new Exploitation Area on this ANH contracted block will also be subject to this additional royalty once the production from each new field exceeds five MMbbl of cumulative production. The Moqueta discovery in the Chaza Block and the Jilguero discovery in the Garibay Block will both be subject to this additional royalty after each field produces five MMbbl.

The ANH has requested that the additional royalty be paid with respect to production from the recently drilled wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, we view the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have initiated the dispute resolution process and filed an arbitration claim. As at December 31, 2012, total cumulative production from the Moqueta field was 0.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is \$15.1 million.

For exploration and production contracts awarded in the 2010 and 2012 Colombia Bid Rounds, including such contracts awarded to Gran Tierra, the high price royalty will apply once the production from the area governed by the contract, rather than any particular Exploitation Area designated under the contract, exceeds five MMbbl of cumulative production. We expect that this criteria for the high price royalty will apply for subsequent bid rounds.

The Santana and Magangué Blocks have a flat 20% royalty as those discoveries were made before 2002. The Guayuyaco and Rio Magdalena Blocks have the sliding scale royalty but do not have the additional royalty.

In addition to these government royalties, Gran Tierra's original interests in the Santana, Guayuyaco, Chaza, Rio Magdalena, Mecaya and Azar Blocks acquired on our entry into Colombia in 2006 are subject to a third party royalty. The additional interest in Guayuyaco and Chaza acquired by Gran Tierra on the acquisition of Solana in 2008 is not subject to this third party royalty. On June 20, 2006, Gran Tierra entered into a participation agreement that would effectively compensate Crosby Capital, LLC ("Crosby") for its share in certain Colombian properties. The compensation is in the form of overriding royalty rights that applies to production from historical properties. The historical properties are Santana, Guayuyaco, Rio Magdalena, Talora (sold), Chaza, Primavera (relinquished), Mecaya and Azar. The overriding royalty rights starts with a 2% rate on working interest production less government royalties. For new commercial fields discovered within 10 years of the agreement date and after a prescribed threshold is reached, Crosby reserves the right to convert the overriding royalty rights to a net profit interest. This net profit interest ranges from 7.5% to 10% of working interest production less sliding scale government royalties, as described above, and operating and overhead costs. No adjustment is made for the HPR royalty. On certain pre-existing fields, Crosby does not have the right to convert its overriding royalty rights to a net profit interest. The overriding royalty rights and net profit interests are calculated on Gran Tierra's working interest production after royalties, excluding the working interest acquired from Solana. In addition, there is a conditional overriding royalty rights that applies only to the pre-existing fields.

Chaza Block

The Chaza Block covers 46,676 gross acres in the Putumayo Basin and is governed by the terms of an Exploration and Exploitation Contract with the ANH, which was signed June 27, 2005. We are the operator and hold a 100% working interest in this block. The discovery of the Costayaco field in the Chaza Block was the result of drilling the Costayaco-1 exploration well in the second quarter of 2007. This well commenced production in July 2007. We were granted an additional exploratory program which extended the exploration phase of the contract to June 26, 2013. The additional exploration phase required one exploration well to be drilled and this obligation was satisfied by the completion of the Pacayaco-1 and Pacayaco-1 ST1 oil exploration wells in 2011. The production phase for this block will end in 2033. After the expiration of the production phase, we must carry out an abandonment program to the satisfaction of ANH. In conjunction with the abandonment, we must establish and maintain an abandonment fund to ensure that financial resources are available at the end of the contract.

In 2012, we drilled and completed the Costayaco-15 and Costayaco-16 development wells and commenced drilling the Costayaco-17 development well in the Costayaco field. We also drilled and completed initial testing of the Moqueta-7 development well and commenced drilling the Moqueta-8 development well in the Moqueta field. We also continued facilities work at the Costayaco and Moqueta fields and acquired 3-D seismic on the Costayaco, Moqueta and Verdayaco fields.

In 2013, we plan to conduct initial testing of the Moqueta-8 development well, drill the Moqueta Deep exploration well and drill five gross development wells.

Guayuyaco Block

The Guayuyaco Block contract was signed in September 2002 and covers 52,366 gross acres in the Putumayo Basin, which includes the area surrounding the producing fields of the Santana contract area. The Guayuyaco Block is governed by an Association Contract with Ecopetrol S.A. ("Ecopetrol"), the Colombian majority state owned oil company. We are the operator and have a 70% working interest, with the remaining interest held by Ecopetrol. Ecopetrol has the option to back-in to a 30% participation interest in any other new discoveries in the block. We have completed all of our obligations in relation to this contract.

The Guayuyaco field was discovered in 2005. Two wells are now producing in this field: Guayuyaco-1 commenced production in February 2005 and Guayuyaco-2 began production in September 2005. The Juanambu field, also in the Guayuyaco Block, has three producing wells: Juanambu-1 began commercial production in November 2007, Juanambu-2 began production in March 2010 and Juanambu-3 began production in April 2011. The production phase of the contract will end in 2030, following which, the property will be returned to the government upon expiration of the production contract, and we are not obligated to perform remediation work.

In 2012, we acquired 3-D seismic on this block. In 2013, we plan to drill the Miraflores West-1 oil exploration well and an additional oil exploration well.

Garibay Block

Solana acquired the Garibay Block in October 2005. The block covers 75,936 gross acres in the Llanos Basin and we have a non-operated 50% working interest. CEPSAC has the remaining interest and is the operator. The block is held under an Exploration and Exploitation Contract with the ANH. We applied and were granted an additional exploratory program which extended the exploration phase of the contract to October 24, 2013. There was an obligation to drill one exploration well in this exploration phase, which we satisfied by drilling the Bordon-1 oil exploration well in 2012. This well was plugged and abandoned in 2012. In 2013, we plan to convert the Jilguero-2 well to a water injector well, acquire 80 square kilometers of 3-D seismic and perform facilities work.

Llanos-22 Block

During 2011, we earned a 45% non-operated working interest in the Llanos-22 Block in the Llanos Basin pursuant to farm-out agreements with CEPSAC (CEPSAC retained a 55% working interest and operatorship). CEPSAC farmed-in for a 30% working interest on the Piedemonte Norte Block. The Llanos-22 Block is held under an Exploration and Exploitation Contract with the ANH and covers 84,757 gross acres. The second exploration phase of the contract requires two wells to be drilled or one well and the relinquishment of 50% of the block prior to February 4, 2015.

Together with our partner, we successfully drilled and tested the Ramiriqui-1 oil exploration well in 2012. In 2013, we plan to drill one gross oil development well which will satisfy the second phase obligation.

Santana Block

The Santana Block contract was signed in July 1987 and covers 1,119 gross acres in the Putumayo Basin and includes 11 gross producing wells in four fields — Linda, Mary, Miraflores and Toroyaco. Activities are governed by terms of a Shared Risk Contract with Ecopetrol and we are the operator. We hold a 35% working interest in all fields and Ecopetrol holds the remaining interest. The block has been producing since 1991. Under the Shared Risk Contract, Ecopetrol initially backed into a 50% working interest upon declaration of commerciality in 1991. In June 1996, when the block reached seven MMbbl of oil produced, Ecopetrol had the right to back into a further 15% working interest, which it exercised, for a total ownership of 65%. We have completed all of our obligations in relation to the contract. The production phase of the contract will end in 2015, at which time the property will be returned to the government and we are not obligated to perform remediation work.

In 2012, we performed minor facilities maintenance. In 2013, no significant capital expenditures are planned.

Sierra Nevada Block

We acquired our interest in the Sierra Nevada Block through the Petrolifera acquisition in March 2011. The Sierra Nevada Block is located in the Lower Magdalena Basin and covers 178,162 gross acres. We are the operator of the block with a 100% working interest. The block is held under an Exploration and Exploitation Contract with the ANH and a third party has a 1% overriding royalty right on the block. We are in the fourth of six exploration phases, which would have ended on December 28, 2012, but we applied to the ANH and were granted a two-month extension to February 28, 2013. The final exploration phase is scheduled to end in June 2014 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we drilled the Florida West exploration well, which was plugged and abandoned and satisfied the fourth phase commitment, and relinquished 15% of the block. In 2013, no significant capital expenditures are planned.

Magdalena Block

We acquired our interest in the Magdalena Block through the Petrolifera acquisition in March 2011. The Magdalena Block is located in the Lower Magdalena Basin and covers 594,803 gross acres. We are the operator of the block with a 100% working interest. The block is held under an Exploration and Exploitation Contract with the ANH and a third party has a 1% overriding royalty right on the block. We are in the third of six exploration phases, which ends on May 1, 2013, and required one exploration well to be drilled; however, we requested and were granted ANH approval to change the work obligation to a 2-D seismic program. The final exploration phase is scheduled to end in February 2016 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we acquired 53 square kilometers of 3-D seismic on this block. In 2013, we plan to acquire 85 kilometers of 2-D seismic on this block to satisfy the third phase obligation.

Piedemonte Norte Block

In June 2009, we completed the conversion of our Technical Evaluation Areas (“TEA”) in the Putumayo Basin to blocks with Exploration and Exploitation Contracts with the ANH. The Piedemonte Norte Block covers 78,742 gross acres in the Putumayo Basin and we hold a 70% working interest. In 2011, we farmed out 30% of the block to CEPASAC, but retained operatorship. This asset swap was in connection with the Llanos-22 Block farm-in agreement. The first exploration phase was to end on October 10, 2012, and required the acquisition, processing and interpretation of 70 kilometers of 2-D seismic; however, the block is under suspension pending receipt of an environmental permit. This contract has six exploration phases and the final exploration phase of the contract ends in October 2017; however, since this block is under suspension, the contract expiration will likely be delayed. The exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures. In 2013, we plan to acquire 70 kilometers of 2-D seismic on this block which will satisfy the first phase obligation.

Piedemonte Sur Block

The Piedemonte Sur Block was part of the Putumayo West A TEA and became an exploration block with an Exploration and Exploitation Contract with the ANH in June 2009. The Piedemonte Sur Block covers 73,898 gross acres in the Putumayo Basin. We are the operator of the block with a 100% working interest. We are in a unified phase two and three of six exploration phases. This phase requires the acquisition of 55 kilometers of 2-D seismic and the drilling of one exploration well by July 26, 2013; however, we expect to apply for an extension of this phase. The exploration phase will end in July 2016 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures. In 2013, we plan to acquire 51 kilometers of 2-D seismic on this block.

Magangué Block

Solana acquired the Magangué Block in October 2006. It is held pursuant to an Association Contract with Ecopetrol and covers 20,647 gross acres in the Lower Magdalena Basin. We are the operator of the block with a 42% working interest and our partner Ecopetrol has the remaining working interest. This block contains the producing Guepaje gas field. The production phase of the contract will end in 2017. We have completed all of our obligations in relation to the contract.

In 2012, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2013.

Mecaya Block

The Mecaya Exploration and Exploitation Contract with the ANH was signed June 2006. The Mecaya Block covers 74,128 gross acres in the Putumayo Basin. We are the operator and have a 15% working interest. Two partners have the remaining working interest. We are in a unified phase one and two of four exploration phases and are obligated to complete 52 square kilometers of 3-D seismic or drill one exploration well. We were contractually obligated to complete this work by June 2009; however, the contract terms have been suspended due to operational difficulties in the area. The exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures on this block, and no significant capital expenditures are planned for 2013.

Cauca 6 Block

We were awarded the Cauca 6 Block in the 2010 Colombia Bid Round. The block covers 571,098 gross acres in the Cauca Basin. We are the operator of the block with a 100% working interest. The block is held under a TEA Contract with the ANH. We are in the exploration phase of the contract which requires the acquisition of 200 kilometers of 2-D seismic and the drilling of one stratigraphic well by December 15, 2014. This TEA contract would then be converted into an Exploration and Exploitation Contract.

In 2012, we conducted surface and subsurface geological studies and an aeromagnetic survey. In 2013, we plan to acquire 200 kilometers of 2-D seismic on this block.

Cauca 7 Block

We were awarded the Cauca 7 Block in the 2010 Colombia Bid Round. The block covers 785,452 gross acres in the Cauca Basin. We are the operator of the block with a 100% working interest. The block is held under a TEA Contract with the ANH. The exploration phase of the contract requires the acquisition of 250 kilometers of 2-D seismic and the drilling of one stratigraphic well by December 15, 2014. This TEA contract would then be converted into an Exploration and Exploitation Contract.

In 2012, we conducted surface and subsurface geological studies and an aeromagnetic survey. In 2013 we plan to acquire 250 kilometers of 2-D seismic on this block.

Putumayo 10 Block

We were awarded the Putumayo 10 Block in June 2010 in the 2010 Colombia Bid Round. The block covers 114,096 gross acres in the Putumayo Basin. We are the operator of the block with a 100% working interest. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the first of two exploration phases of the contract. This phase requires the acquisition of 73 kilometers of 2-D seismic and two exploration wells to be drilled by September 15, 2014. The exploration phase ends in September 2017 and the exploitation phase would end 24 years after commerciality if a discovery is approved.

In 2012, there were no significant capital expenditures. In 2013, we plan to acquire 100 kilometers of 2-D seismic on this block.

Putumayo 1 Block

We acquired a 55% operated working interest in the Putumayo-1 Block in 2010. The block covers 114,881 gross acres in the Putumayo Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the first of two exploration phases. This phase required the acquisition of 159 square kilometers of 3-D seismic and one exploration well to be drilled by May 3, 2012; however, we requested and were granted an extension to May 3, 2013. The exploration phase ends in September 2015 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we initiated the acquisition of 3-D seismic on this block and, in 2013, we plan to acquire a further 228 square kilometers of 3-D seismic and drill one gross oil exploration well.

Catguas A and B Blocks

Solana acquired the Catguas Block in November 2005. We are the operator of the block which covers 330,354 gross acres in the Catatumbo Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We have a 100% working interest in the block; however, in December 2005, Solana and its partner signed a participation agreement whereby they defined the areas A and B and distributed them between the partners in the block. The participation agreement will transfer a 15% working interest in the southern part of the block (Catguas B) and a 50% working interest in the remainder of the block (Catguas A) to our partner. This agreement is subject to approval by ANH. Catguas A covers 74,119 gross acres and Catguas B covers 256,235 gross acres. We are in a unified phase two and three of six exploration periods in the contract. This phase was to end in May 2007; however, the block contract is in suspension by ANH as a result of force majeure. This phase requires three exploratory wells or two exploratory wells to be drilled and one re-entry and the acquisition of 50 square kilometers of 3-D seismic. There will be two subsequent exploration periods of 12 months each in length, which both require the drilling of one exploration well. The exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures on this block, and no significant capital expenditures are planned for 2013.

Sinu-1 Block

We acquired a 60% operated working interest in the Sinu-1 Block in the 2012 Colombia Bid Round. The block covers 503,000 gross acres in the Sinu Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the community consultation phase which will end on November 28, 2013.

Sinu-3 Block

We acquired a 51% operated working interest in the Sinu-3 Block in the 2012 Colombia Bid Round. The block covers 483,000 gross acres in the Sinu Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the community consultation phase which will end on November 28, 2013.

Turpial Block

We acquired our interest in the Turpial Block through the Petrolifera acquisition in March 2011. The Turpial block is located in the Middle Magdalena Basin in central Colombia and covers 111,066 gross acres. We are the operator of the block with a 50% working interest and our partner holds the remaining working interest. The block is held under an Exploration and Exploitation Contract with the ANH and a third party has a 1% overriding royalty right on the block. We are in the fourth phase of six exploration phases. This phase requires one exploration well to be drilled by November 3, 2013. The exploration phase will end in August 2015 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we drilled the Turpial-1 oil exploration well which satisfied the fourth exploration phase commitment. In 2013, no significant capital expenditures are planned.

Azar Block

We have a 100% working interest in the Azar Block; however, we have entered two farm-out agreements to transfer 60% of our working interest. The farm-outs are subject to ANH approval. This block covers 47,226 gross acres in the Putumayo Basin and we are the operator. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the sixth exploration phase which requires one exploration well to be drilled. The exploitation phase would end 24 years after commerciality, if a discovery is approved. The property will be returned to the government upon expiration of the production contract. If we make a commercial discovery on the block and produce oil, we will be obligated to perform abandonment activities under the same conditions as those for the Chaza Block.

In 2012, we drilled the La Vega Este-1 oil exploration well which was plugged and abandoned during the year, and satisfied the fifth exploration phase well commitment. In 2013, no significant capital expenditures are planned.

Rumiyaco Block

The Rumiyaco Block was part of the Putumayo West B TEA and became an exploration block with an Exploration and Exploitation Contract with the ANH in June 2009. Rumiyaco covers 82,624 gross acres in the Putumayo Basin. We are the operator of the block with a 100% working interest. We are in the fourth of six exploration phases. This phase requires one exploration well to be drilled by September 4, 2013. The exploration phase ends in September 2015 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

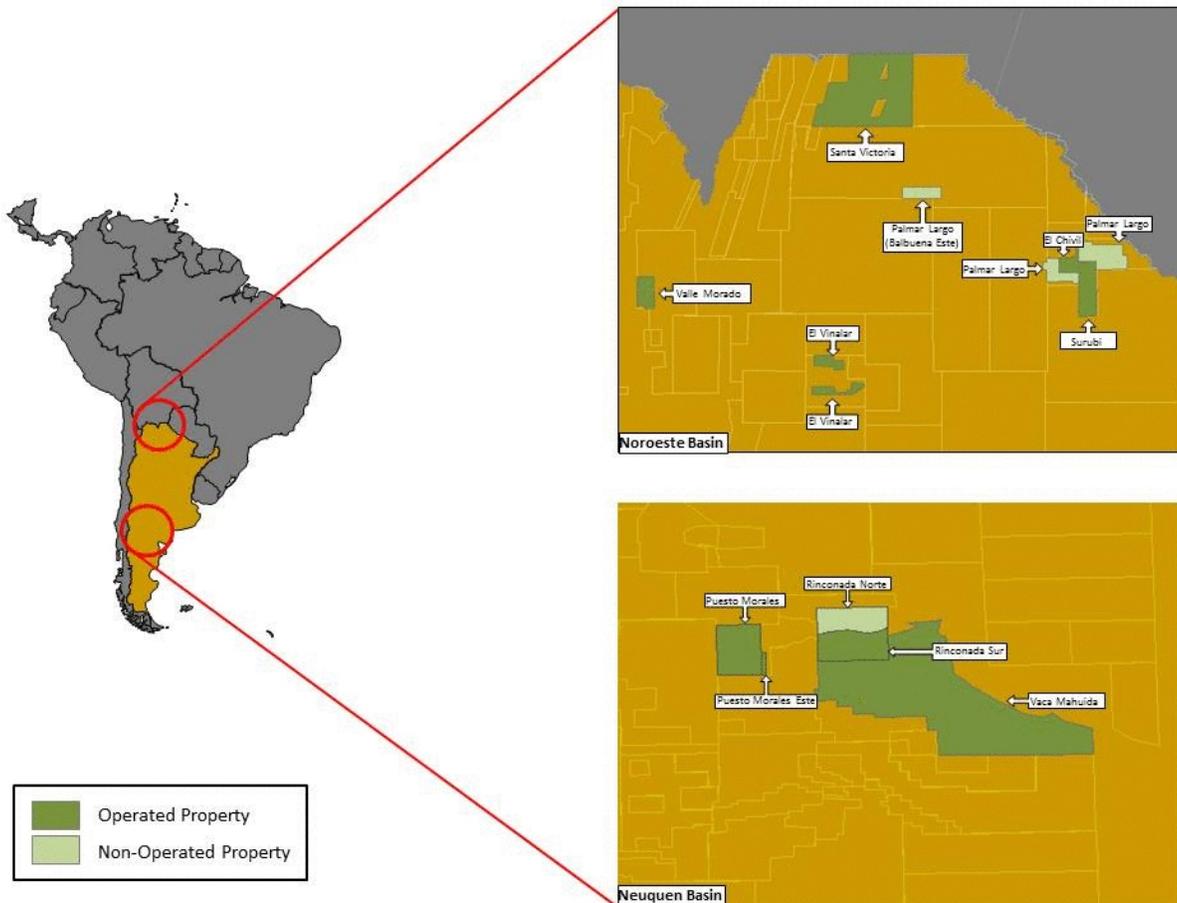
In 2012, we acquired 52 square kilometers of 3-D seismic on this block. In 2013, no significant capital expenditures are planned.

Rio Magdalena Block

The Rio Magdalena Association Contract with Ecopetrol was signed in February 2002. The Rio Magdalena Block covers 36,156 gross acres in the Magdalena Basin. We are the operator of the block and hold a 70% working interest. An agreement to transfer a further interest to our partner and reduce our working interest to 30.8% is pending approval by Ecopetrol. According to the terms of the Association Contract, Ecopetrol may back-in for a 30% working interest in any discoveries on the block upon commercialization. The exploration phase of the contract ended on September 14, 2010, and the production period will end in 2030, at which time the property will be returned to the government. As a result, there will be no reclamation costs.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

Oil and Gas Properties – Argentina



Our Argentina properties are located in the Noroeste Basin in northern Argentina and the Neuquen Basin in central Argentina. The Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Surubi, El Chivil, Palmar Largo and El Vinalar Blocks have producing oil wells and the Puesto Morales Block also has producing gas wells. During the year ended December 31, 2012, 12% of our consolidated production, NAR adjusted for inventory changes, was from the Puesto Morales Block and 6% was from the Surubi Block. For all of our blocks in Argentina, upon expiry of the block rights, ownership of producing assets will revert to the provincial government.

As some of our oil production in Argentina is trucked to a local refinery, sales of oil in the Noroeste Basin can be seasonally delayed by adverse weather and road conditions, particularly during the months November through February when the area is subject to periods of heavy rain and flooding. While storage facilities are designed to accommodate ordinary disruptions without curtailing production, delayed sales will delay revenues and may adversely impact our working capital position in Argentina.

We relinquished our interest in the Puesto Guevara Block during 2012.

Royalties in Argentina are based on a provincial royalty plus an additional provincial turnover tax. The provincial royalty rate is 24% for the Puesto Morales Este Block and 12% on all other blocks in Argentina. The provincial turnover tax ranges from 1.5% to 3% on our blocks.

Rio Negro Province, which includes the Puesto Morales, Puesto Morales Este, Rinconada Norte and Rinconada Sur Blocks, has enacted new legislation that changes the royalty regime associated with concession agreement extensions. Royalties in Rio Negro Province will increase a minimum of 3.5% and a required bonus payment, not determinable at this time, will be negotiated for the concession agreement extension. In addition, there is an additional royalty component of 0.5% per dollar per bbl on realized oil prices greater than \$80 per bbl and 0.5% per dollar per MMBtu for gas prices above \$3.50 per MMBtu. Under the new legislation, negotiations are required to be carried out within the first half of 2013 and the resulting new terms are expected to come into effect immediately thereafter.

Puesto Morales Block

We acquired our interest in the Puesto Morales Block through the Petrolifera acquisition in March 2011. The Puesto Morales Block covers 31,254 gross acres. We are the operator of the block with a 100% working interest. The contract was awarded on October 18, 2010, and the exploitation phase will end on January 22, 2016, with a possible ten year extension. We have commenced negotiations for an extension. We have no work commitments on this block.

In 2012, we drilled and completed seven development wells and commenced drilling an additional two development wells, one of which was suspended, continued a well workover program, commenced a waterflood program and performed facility upgrades. In 2013, we plan to drill five development wells, continue the waterflood and workover programs and perform facilities upgrades.

Rinconada Sur Block

We acquired our interest in the Rinconada Sur Block through the Petrolifera acquisition in March 2011. The Rinconada Sur Block covers 28,417 gross acres and is part of the Puesto Morales concession. We are the operator of the block with a 100% working interest. The contract was awarded on October 18, 2010, and the exploitation phase will end on January 22, 2016, with a possible ten year extension. We have no work commitments on this block.

In 2012, we completed one development well and drilled one exploration well which was plugged and abandoned subsequent to year-end. In 2013, no significant capital expenditures are planned.

Puesto Morales Este Block

We acquired our interest in the Puesto Morales Este Block through the Petrolifera acquisition in March 2011. The Puesto Morales Este Block covers 1,483 gross acres. We are the operator of the block with a 100% working interest. The contract was awarded on October 18, 2010, and the exploitation phase will end on October 17, 2035, with a possible five year extension. We have no work commitments on this block.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

Rinconada Norte Block

We acquired our interest in the Rinconada Norte Block through the Petrolifera acquisition in March 2011. The Rinconada Norte Block covers 23,475 gross acres. We have a 35% non-operated working interest. Our partner is the operator and has the remaining working interest. This is an exploitation concession and the exploitation phase will end on January 22, 2016, with a possible ten year extension. We have no work commitments on this block.

In 2012, our partner drilled four gross exploration wells and three gross development wells. One exploration well was producing at year-end, one was plugged and abandoned and two were under evaluation. One development well was completed during the year and two wells were in progress at year-end. In 2013, no significant capital expenditures are planned.

Surubi Block

We purchased the Surubi Block in late 2006. We are the operator of the Surubi Block, which covers 90,811 gross acres, and have an 85% working interest. In 2008, we drilled the Proa-1 discovery well, which began production in September 2008. The provincial oil company, Recursos Energeticos Formosa S.A., farmed-in to the block for a 15% working interest, and is paying its share of well costs from its share of production from the Proa-1 well. The contract for this block will end on August 17, 2026. We have no work commitments on this block.

In 2012, we drilled and completed the Proa-2 development well, which began production in April 2012. In 2013, we plan to perform facilities work.

El Chivil Block

We purchased the El Chivil Block in 2006. We are the operator and hold a 100% working interest in the block which covers 30,393 gross acres. The contract for this block will end on September 7, 2015, with a possible ten year extension . We have no work commitments on this block.

In 2012, regular field maintenance and workover activities were performed and the same are planned for 2013.

Palmar Largo Block

We purchased a 14% non-operated working interest in the Palmar Largo Block in September 2005. Three partners hold the remaining working interest. The Palmar Largo Block covers 186,441 gross acres. This asset comprises several producing oil fields in the Noroeste Basin and is subdivided into three sub-blocks, including Balbuena Este. The Palmar Largo Block contract will end in 2017, with a possible ten year extension . We have no work commitments on this block.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

El Vinalar Block

In June 2006, we acquired a 50% working interest in the El Vinalar Block, which covers 61,035 gross acres. We are the operator of the block. The El Vinalar Block contract will end on April 19, 2016, with a possible ten year extension . We have no work commitments on this block.

In 2012, there were no significant capital expenditures. In 2013, we plan to perform workovers and facilities upgrades.

Valle Morado Block

We purchased our original interest in the Valle Morado Block in 2006 and purchased a further 3.4% working interest during 2011. This block covers 44,446 gross acres and we are the operator with a 96.6% working interest. The Valle Morado GTE.St.VMor-2001 well was first drilled in 1989. A previous operator completed a 3-D seismic program over the field and constructed a gas plant and pipeline infrastructure. Production began in 1999 from the GTE.St.VMor-2001 well, but was shut-in in 2001 due to water incursion. During 2008, we performed long-term testing on the well. In July 2010, we commenced a re-entry and sidetrack operation on the well; however, these operations were suspended in February 2011 and the wellbore was abandoned due to operational challenges. We continue to review alternatives associated with the field development. The contract for this block expires in 2034. We have no work commitments on this block. In 2012, there were no significant capital expenditures and no significant expenditures are planned for 2013.

Santa Victoria Block

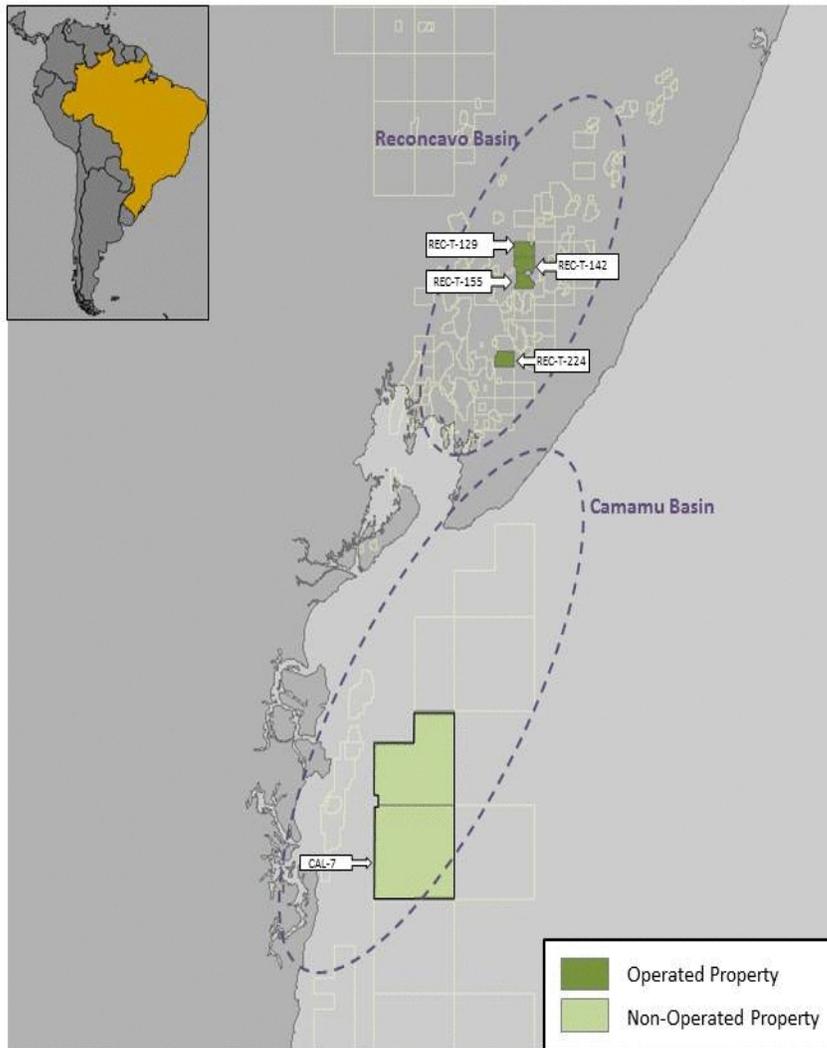
We purchased the Santa Victoria Block in 2006. This block covers 516,942 gross acres. We are the operator and have a 50% working interest. In 2011, we relinquished 50% of the block as a condition to enter into the second phase and also farmed-out 50% of our working interest. In 2013, we expect to assume, subject to regulatory approval, a 100% working interest, due to our joint venture partner's decision to leave the joint venture. We are in the second of three exploration phases. This phase requires one exploration well to be drilled or 720 units of work (\$3.6 million) to be completed by March 29, 2013, but we have commenced negotiations to extend the expiry date of this phase. The exploration phase ends in March 2014. In 2012, there were no significant capital expenditures. In 2013, we plan to drill a gas exploration well.

Vaca Mahuida Block

We acquired our interest in the Vaca Mahuida Block through the Petrolifera acquisition in March 2011. The Vaca Mahuida Block covers 253,331 gross acres. We are the operator and have a 25% working interest. Our three partners share the remaining working interest. After three gas discoveries in 2010, an exploitation concession was requested and we are awaiting regulatory approval. We satisfied our obligation to perform long-term production gas tests and are evaluating the potential of these prospects and the block. We have no work commitments on this block.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

Oil and Gas Properties - Brazil



In September 2012, we received declaration of commerciality for the Tiê field on Block REC-T-155. On October 8, 2012, we received Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") approval and acquired the remaining 30% working interest in our four exploration blocks in the Recôncavo Basin pursuant to the terms of a purchase and sale agreement dated January 20, 2012. With the exception of one block which has three producing wells, the remaining blocks are unproved properties.

In September 2011, we announced farm-out agreements with Statoil pursuant to which we would receive an assignment from Statoil of a non-operated 10% working interest in Block BM-CAL-7 and a non-operated 15% working interest in Block BM-CAL-10. In 2012, we received ANP approval for Block BM-CAL-7 and the assignment became effective on April 3, 2012.

During the first quarter of 2012, the ANP announced the 1-STAT-7-BAS exploration well drilling had been completed on Block BM-CAL-10. In accordance with the terms of the farm-out agreement, we gave notice to Statoil that we would not enter into and assume our share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farm-out agreement terminated and we did not receive any interest in Block BM-CAL-10.

All of our onshore blocks in Brazil are subject to an 11% royalty, which consists of a 10% crown royalty and a 1% landowner royalty. Our offshore blocks are subject to a 10% crown royalty.

Blocks REC-T-129, REC-T-142, REC-T-155, and REC-T-224

Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 are located approximately 70 kilometers northeast of Salvador, Brazil in the Recôncavo Basin and cover 27,075 gross acres. We are the operator with a 100% working interest. On October 8, 2012, we received regulatory approval and acquired the remaining 30% working interest in these blocks. All four blocks are in the second exploration phase which will end in the fourth quarter of 2013. This phase requires the drilling of an exploration well on each block.

In 2012, we drilled and completed two development wells, 3-GTE-03-BA and 4-GTE-04-BA, in the Tiê field on Block REC-T-155 and drilled a horizontal oil exploration well, 1-GTE-05HP-BA, on Block REC-T-142. In 2013, we plan to drill two horizontal exploration wells on Block REC-T-155 and Block REC-T-129, perform additional completion work on the 3-GTE-03-BA and 3-GTE-04-BA producing wells in the Tiê field and perform fracture stimulation operations on Block REC-T-142. We also plan to perform facilities and pipeline work on Block REC-T-155.

Block BM-CAL-7

Block BM-CAL-7 is located in the Camamu Basin, offshore Bahia, Brazil and covers 337,561 gross acres. We have a 10% non-operated working interest in this block. We received ANP approval for this working interest during 2012 and the assignment became effective on April 3, 2012. Block BM-CAL-7 is in the first of two exploration phases which is due to end in April 2013, but we have applied to the ANP for a 12 month extension. This phase requires one exploration well to be drilled and the acquisition of 1,366 square kilometers of 3-D seismic. Our partner had previously satisfied the seismic commitment and, in 2012, we purchased an existing 3-D seismic program. In 2013, we plan to conduct evaluation work to mature prospects for drilling expected to take place in 2014.

Oil and Gas Properties - Peru



On January 17, 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block and operatorship to us. During June 2012, we entered into an agreement to acquire the remaining 40% working interest in Block 95. Subsequent to December 31, 2012, we received regulatory approval for the assignment of the remaining 40% working interest. In the fourth quarter of 2012, we increased our working interest in Blocks 123 and 129 to 100%, subject to regulatory approval, and, in January 2013, assumed operatorship.

All blocks in Peru are subject to a license agreement with PeruPetro. There is a 5-20%, sliding scale, royalty rate on the lands, dependent on production levels. Production less than 5,000 BOPD is assessed a royalty of 5%, for production between 5,000 and 100,000 BOPD there is a linear sliding scale between 5% and 20%. Production over 100,000 BOPD has a flat royalty of 20%. This royalty structure applies to all blocks in Peru that we have an interest in. Block 133 has an additional royalty factor of 15%.

Block 95

In December 2010, we acquired a 60% working interest in Block 95 and, during the second quarter of 2012, we entered into an agreement to acquire the remaining 40% working interest. Subsequent to December 31, 2012, we received regulatory approval and the Public Deed for the assignment of the remaining interest. We are the operator of this block. Block 95 has an area of 1,274,399 gross acres. An oil field has already been discovered on Block 95, with a discovery well drilled in 1974 flowing 807 BOPD naturally without pumps. We are in the third exploration phase of six which required the drilling of one well or the completion of 400 units of work. This phase was delayed as a result of force majeure. Force majeure ended in December 2012 and we were granted a six month extension to June 27, 2013. In 2012, we completed civil construction of a drilling platform and dock facility and commenced drilling an oil exploration well. We also applied for a variety of permits in preparation for drilling the oil exploration well and for future seismic programs. In 2013, we completed drilling of the exploration well and obtained initial well-log results, which indicated an oil saturated reservoir. We plan to extend the exploration well with a horizontal leg to initiate long-term testing. Timing for initiation of the long-term testing has not been determined yet, but it is expected to commence within a period of 12 months, subject to facilities upgrade, and execution of crude oil transportation and delivery agreements.

Block 123 and Block 129

In September 2010, we acquired a 20% working interest in Block 123 and Block 129. In October 2012, we increased our working interest in Blocks 123 and 129 to 100% through the assumption of our partners' interests, subject to regulatory approval, and assumed operatorship on January 1, 2013. Blocks 123 and 129 have a total area of 3,491,240 gross acres. We are in the third exploration phase of five on Block 123, which was to end on November 29, 2012, but we applied for and were granted two three month extensions to May 31, 2013. On Block 129, the third exploration phase of five was due to end on February 26, 2013, but we applied for and were granted a six month extension to August 26, 2013. This phase requires the acquisition of 2-D seismic totaling 504 kilometers over the two blocks.

In 2012, we acquired 2-D seismic on these blocks. In 2013, we plan to acquire 567 kilometers of 2-D seismic and pursue Environmental Impact Assessment ("EIA") approvals.

Block 107

We acquired our interest in Block 107 through the Petrolifera acquisition in March 2011. Block 107 covers 623,504 gross acres. We are the operator of the block with a 100% working interest and a third party has a 3% overriding royalty right on the block. We are in the fourth and final exploration phase, which requires one exploration well to be drilled or 300 units of work. The block has been under force majeure since May 25, 2012. The fourth phase will end 12 months after force majeure is lifted, but we plan to apply for an extension of the exploration period.

In 2012, we acquired an overriding royalty right that was held by a third party and advanced permitting for drilling. In 2013, we plan to complete a 392 kilometer infill 2-D seismic program, which will satisfy our fourth phase work obligation, and begin pre-drilling activities.

Block 133

We acquired our interest in Block 133 through the Petrolifera acquisition in March 2011. Block 133 covers 978,663 gross acres. We are the operator of the block with a 100% working interest. We are in the second exploration phase of four, which was to end on February 14, 2013; however, PeruPetro has frozen the phase until June 7, 2013. This phase requires the acquisition of 150 kilometers of 2-D seismic which will be followed by the relinquishment of 20% of the block.

In 2012, we performed G&G studies. In 2013, we plan to complete airborne gravity and magnetic surveys and request approval for this work to satisfy the second phase work obligation. We also plan to continue EIAs.

Reserves

The following table sets forth our reserves as of December 31, 2012. The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. "Risk Factors". The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. Therefore the accuracy of the reserve estimate is dependent on the quality of the data, the accuracy of the assumptions based on the data, and the interpretations and judgment related to the data.

We have developed internal policies for estimating and evaluating reserves. The policies we have developed are applied company wide, and are comprehensive in nature. Gran Tierra's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation by our reserves committee, and 100% of our reserves are evaluated by an independent reservoir engineering firm, GLJ Petroleum Consultants Ltd., at least annually.

The primary internal technical person in charge of overseeing the preparation of our reserve estimates is the General Manager of Engineering and Development Planning. He has a Bachelor of Science degree in petroleum engineering and is a professional engineer and member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He is responsible for our engineering activities including reserves reporting, asset evaluation, reservoir management, and field development. He has over 30 years of industry experience in various domestic and international engineering and management roles.

The technical person responsible for overseeing the reserves evaluation is a Vice President, Corporate Evaluations of GLJ Petroleum Consultants Ltd. He has a Bachelor of Science degree in engineering physics and is a registered professional engineer in the Province of Alberta. He has over 20 years of industry experience in various domestic and international engineering and management roles.

By applying our policies we have developed SEC compliant reserve estimates and disclosures. Our policies are applied by all staff involved in generating and reporting reserve estimates including geological, engineering and finance personnel. Calculations and data are reviewed at multiple levels of the organization to ensure consistent and appropriate standards and procedures.

No estimates of reserves comparable to those included herein have been included in a report to any federal agency other than the SEC.

Reserves Category	Liquids (1) (Mbbbl)	Natural Gas (MMcf)
Proved		
Developed		
Colombia	24,677	8,551
Argentina	2,459	2,777
Brazil	347	—
Total proved developed reserves	27,483	11,328
Undeveloped		
Colombia	6,432	921
Argentina	3,335	527
Brazil	1,244	—
Total proved undeveloped reserves	11,011	1,448
Total proved reserves	38,494	12,776
Probable		
Developed		
Colombia	5,673	783
Argentina	716	298
Brazil	397	—
Total probable developed reserves	6,786	1,081
Undeveloped		
Colombia	5,242	2,517
Argentina	1,814	1,538
Brazil	942	—
Total probable undeveloped reserves	7,998	4,055
Total probable reserves	14,784	5,136
Possible		
Developed		
Colombia	4,739	1,902
Argentina	1,447	695
Brazil	686	—
Total possible developed reserves	6,872	2,597
Undeveloped		
Colombia	8,428	2,337
Argentina	4,772	46,733
Brazil	1,384	—
Total possible undeveloped reserves	14,584	49,070
Total possible reserves	21,456	51,667

(1) Liquids include oil and NGLs. We have NGL reserves in small amounts in Colombia and Argentina only. Brazil liquids reserves are 100% oil.

Proved Undeveloped Reserves

At December 31, 2012, we had total proved undeveloped reserves NAR of 11.2 MMBOE (December 31, 2011 - 8.2 MMBOE), including 6.6 MMBOE in Colombia (December 31, 2011 – 4.6 MMBOE), 3.4 MMBOE in Argentina (December 31, 2011 – 3.3 MMBOE) and 1.2 MMBOE in Brazil (December 31, 2011 – 0.3 MMBOE). Approximately 27% of proved undeveloped reserves are located in our Puesto Morales field in Argentina. This field was acquired as a result of the Petrolifera acquisition in 2011. Additionally, approximately 22% and 28% of proved undeveloped reserves are in our Moqueta and Costayaco fields in Colombia. None of our proved undeveloped reserves at December 31, 2012, have remained undeveloped for five years or more since initial disclosure as proved reserves and we have adopted a development plan which indicates that the proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure as proved reserves.

Significant changes in proved undeveloped reserves are summarized in the table below:

	Oil Equivalent (MMBOE)
Balance, December 31, 2011	8.2
Purchases	0.1
Discoveries and extensions	3.9
Converted to proved producing	(3.6)
Technical revisions	2.6
Balance, December 31, 2012	11.2

In 2012, we converted 3.6 MMBOE, or 44% of the total year-end 2011 proved undeveloped reserves, to developed status. In 2012, we made investments, consisting solely of capital expenditures, of \$44.0 million in Colombia and \$19.5 million in Argentina associated with the development of proved undeveloped reserves. Approximately 94% of proved undeveloped reserves conversions occurred in the Costayaco and Moqueta fields in Colombia and 3% in the Puesto Morales field in Argentina. The majority of proved undeveloped conversions occurred as a result of ongoing development activities in the Costayaco and Moqueta fields in Colombia, including infill drilling and a pressure maintenance project in the Costayaco field and infill drilling and facilities development in the Moqueta field. The waterflood optimization program for the Sierra Blancas reservoir and the commencement of a horizontal well development program for the Loma Montosa reservoir, both in the Puesto Morales field in Argentina, also converted proved undeveloped reserves to proved developed reserves.

Sensitivity of Reserves to Prices by Principal Product Type and Price Scenario

The following table sets forth our reserves as at December 31, 2012, using different price cases involving changes to the Brent price. Firstly with a 10% increase and secondly with a 10% decrease. Natural gas prices are not affected by Brent, therefore the volumes of natural gas reserves do not change. Additionally, the oil price in Argentina is set by the government as described below under the caption “Marketing and Major Customers”. Oil prices in Argentina are not sensitive to changes in Brent prices, therefore the price scenarios considered do not result in changes to oil and natural gas reserves for Argentina. Cost schedules were held constant for the two price cases.

Price Case	Proved Reserves		Probable Reserves		Possible Reserves	
	Liquids (Mbb)(1)	Natural Gas (MMcf)	Liquids (Mbb)	Natural Gas (MMcf)	Liquids (Mbb)(1)	Natural Gas (MMcf)
Brent +10%						
Colombia	31,192	9,705	10,529	3,310	13,077	3,948
Argentina	5,794	3,304	2,530	1,836	6,219	47,427
Brazil	1,593	—	1,341	—	2,072	—
	<u>38,579</u>	<u>13,009</u>	<u>14,400</u>	<u>5,146</u>	<u>21,368</u>	<u>51,375</u>
Brent – 10%						
Colombia	30,964	9,443	11,178	3,347	13,621	4,255
Argentina	5,794	3,304	2,530	1,836	6,219	47,427
Brazil	1,586	—	1,334	—	2,063	—
	<u>38,344</u>	<u>12,747</u>	<u>15,042</u>	<u>5,183</u>	<u>21,903</u>	<u>51,682</u>

(1) Proved and possible liquid reserves are higher as a result of a 10% decrease in Brent as compared with a 10% increase in Brent. The lower price results in reduced additional government and third party royalties paid, increasing the NAR volumes.

Production Revenue and Price History

Certain information concerning oil and natural gas production, prices, revenues and operating expenses for the three years ended December 31, 2012, is set forth in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and in the Unaudited Supplementary Data provided following our Financial Statements in Item 8, which information is incorporated by reference here. We prepared the estimate of standardized measure of proved reserves in accordance with the Financial Accounting Standards Board (“FASB”) ASC 932, “Extractive Activities – Oil and Gas”.

Drilling Activities

The following table summarizes the results of our exploration and development drilling activity for the past three years. Wells labeled as “In Progress” were in progress as of December 31, 2012.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	—	—	1.00	0.50	4.00	3.50
Dry	3.00	2.50	6.00	6.00	1.00	1.00
In Progress	2.00	0.95	1.00	0.44	3.00	2.43
Development						
Productive	3.00	3.00	8.00	7.20	2.00	1.70
Dry	—	—	1.00	1.00	—	—
In Progress	2.00	2.00	—	—	2.00	2.00
Total Colombia	10.00	8.45	17.00	15.14	12.00	10.63
Argentina						
Exploration						
Productive	1.00	0.35	2.00	0.70	—	—
Dry	2.00	1.35	1.00	1.00	—	—
In Progress	3.00	1.70	2.00	0.70	—	—
Development						
Productive	10.00	9.20	3.00	3.00	—	—
Dry	1.00	1.00	—	—	—	—
In Progress	3.00	1.70	2.00	2.00	1.00	0.93
Total Argentina	20.00	15.30	10.00	7.40	1.00	0.93
Brazil						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	1.00	1.00	2.00	1.40	—	—
Development						
Productive	2.00	2.00	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	1.00	0.70	—	—
Total Brazil	3.00	3.00	3.00	2.10	—	—
Peru						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	1.00	1.00	—	—
In Progress	1.00	1.00	—	—	—	—
Development						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Total Peru	1.00	1.00	1.00	1.00	—	—
Total	34.00	27.75	31.00	25.64	13.00	11.56

In 2012, we also undertook a pressure maintenance project in the Costayaco field in Colombia and the Puesto Morales Block in Argentina. We also undertook a waterflood optimization program for the Sierra Blancas reservoir in Argentina.

As at February 20, 2013, the results of wells in progress at December 31, 2012, are as follows:

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
Colombia	1.00	1.00	—	—	3.00	1.95
Argentina	2.00	1.35	—	—	4.00	2.05
Brazil	—	—	—	—	1.00	1.00
Peru	—	—	—	—	1.00	1.00
	<u>3.00</u>	<u>2.35</u>	<u>—</u>	<u>—</u>	<u>9.00</u>	<u>6.00</u>

Well Statistics

The following table sets forth our producing wells as of December 31, 2012:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia (1)	29.0	20.5	1.0	0.4	30.0	20.9
Argentina (2)	85.0	70.1	11.0	11.0	96.0	81.1
Brazil	3.0	3.0	—	—	3.0	3.0
Peru	—	—	—	—	—	—
	<u>117.0</u>	<u>93.6</u>	<u>12.0</u>	<u>11.4</u>	<u>129.0</u>	<u>105.0</u>

(1) Includes 5.0 gross and net water injector wells and 20.0 gross and 15.9 net wells with multiple completions.

(2) Includes 15.0 gross and net water injector wells and 1.0 gross and net well with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2012:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia	459,663	346,667	4,000,524	3,357,946	4,460,187	3,704,613
Argentina	706,640	296,905	561,388	301,401	1,268,028	598,306
Brazil	5,786	5,786	358,849	55,044	364,635	60,830
Peru	—	—	6,367,806	6,367,806	6,367,806	6,367,806
	<u>1,172,089</u>	<u>649,358</u>	<u>11,288,567</u>	<u>10,082,197</u>	<u>12,460,656</u>	<u>10,731,555</u>

(1) Excluded from undeveloped acreages are farm-out or assignment agreements for which government approval is pending. These pending approvals will result in a decrease of 210,692 net acres in Colombia and an increase of 3,302,752 net acres in Peru.

At December 31, 2012, our gross undeveloped acreage was located 56% in Peru (11% Block 95 and 31% Blocks 123 and 129), 36% in Colombia, 5% in Argentina and 3% in Brazil.

Business Strategy

Our plan is to continue to build an international oil and gas company through acquisition and exploitation of under-developed prospective oil and gas assets, and to develop these assets with exploration and development drilling to grow commercial reserves and production. Our initial focus is in select countries in South America, currently Colombia, Argentina, Peru, and Brazil; we will consider other regions for future growth should those regions make strategic and commercial sense in creating additional value.

We have applied a two-stage approach to growth, initially establishing a base of production, development and exploration assets by selective acquisitions, and secondly achieving additional reserve and production growth through drilling. We intend to duplicate this business model in other areas as opportunities arise. We pursue opportunities in countries with proven petroleum systems; attractive royalty, taxation and other fiscal terms; and stable legal systems.

A key to our business plan is positioning and being in the right place at the right time with the right resources. The fundamentals of this strategy are described in more detail below:

- Position in countries that are welcoming to foreign investment, that provide attractive fiscal terms, that have stable legal systems, that offer opportunities that we believe have been previously ignored or undervalued, and that have an active market with many available deals;
- Build a balanced portfolio of production, development and exploration assets and opportunities, with a drilling inventory that balances risks and rewards to create value;
- Retain operatorship of assets whenever possible to retain control of work programs, budgets, prospect generation, drilling operations and development activities; non-operating positions will be taken when operators bring strategic advantage to business growth;
- Engage qualified, experienced and motivated professionals;
- Establish an effective local presence, with strong constructive relationships with host governments, ministries, agencies and communities in which we operate;
- Consolidate land and properties in close proximity to build operating efficiency; and
- Manage asset and drilling portfolios closely, assessing value to the company and making changes where needed.

Research and Development

We have not expended any resources on pursuing research and development initiatives. We use existing technology and processes for executing our business plan.

Marketing and Major Customers

Colombia

Our oil in Colombia is good quality light oil, with 95% of production coming from the Putumayo Basin with an average API of 29° to 30°. Ecopetrol is the purchaser of most of our Colombia crude oil production and the source of the majority of our revenues. Sales to Ecopetrol accounted for 74%, 87% and 96%, of our consolidated revenues in 2012, 2011 and 2010, respectively.

We have entered into agreements to sell to Ecopetrol the volume of crude oil production produced in the Chaza Block, Santana Block and Guayuyaco Block (the "Putumayo production"). The volume of crude oil does not include the volume of oil owned by the ANH corresponding to royalties, other than HPR royalties. These agreements are subject to renegotiation periodically and generally contain mutual termination provisions with 30 days' notice. The expiry dates of these agreements have been extended multiple times, and will expire November 30, 2013. In the event that Ecopetrol does not accept a full delivery of this production, we may sell to another party the crude oil not accepted. We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and trucking.

Prior to the end of January 2012, the sales point for our sales to Ecopetrol of the Putumayo production to be exported through the Port of Tumaco on the Pacific coast of Colombia was a point in the Putumayo Basin. Beginning in February 2012, the sales point was changed to the Port of Tumaco. Due to the change in the sales point for Putumayo production to the Port of Tumaco, we entered into crude oil transportation agreements with Ecopetrol pursuant to which we pay to Ecopetrol a transportation tariff and transportation tax for the transportation by Ecopetrol of the Putumayo production from the Putumayo Basin to the Port of Tumaco. Under these agreements, Ecopetrol is liable for risk of loss of oil during transportation only if Ecopetrol fails to take reasonable measures to operate the pipeline or is grossly negligent. Currently we have Firm Capacity Transportation Agreements for 6,000 BOPD that are in place for eight years and the remainder of our Putumayo production is transported through the spot agreements. The later agreements are due to expire on June 30, 2013, but contemplate the transfer of pipeline assets to a wholly owned subsidiary of Ecopetrol, CENIT S. A. S. ("CENIT"), at which time Ecopetrol will assign the transportation agreements, as so amended, to CENIT.

In the event Ecopetrol does not accept a full delivery of our production, we have three alternative purchasers: Gunvor Colombia SAS ("Gunvor"), Petrobras Colombia Limited ("Petrobras Colombia") and one other short-term customer. Sales to Gunvor, Petrobras Colombia and the short-term customer accounted for 2%, 4% and 6% of our consolidated revenues during the year ended December 31, 2012, respectively.

During January 2013, we sold approximately 7,500 BOPD to Gunvor. We are under no obligation to sell any oil to Gunvor until we specify for a particular day the amount of oil we wish to sell to them. Oil is delivered to Gunvor at the Costayaco battery and the sales point is where the oil is loaded into a truck at our loading facility. The Gunvor agreements will expire on December 2, 2013. Oil is delivered to Petrobras Colombia at facilities at Guaduas or Vasconia Station and this is the sales point. We are under no obligation to sell any oil to Petrobras Colombia. Our third short-term customer in Colombia permits us to use excess capacity on their pipeline to transport our oil to the Port of Coveñas up to a maximum of 5,000 BOPD with no minimum volume obligation. For this customer, the delivery point is when the oil is loaded into their trucks, but the sales point is when oil is loaded into their export tanker, which is subject to the export program and off-take procedures of the port of Coveñas.

The majority of the oil produced is transported by pipeline. Varying amounts of oil are trucked: (1) from Santana Station to Ecopetrol's storage terminal at Orito, a distance of approximately 46 kilometers, (2) from the Costayaco field to Ecopetrol's storage terminal at Neiva (Dina Station), approximately 350 kilometers north of the Chaza Block, (3) from the Costayaco field to the Atlántico Oil Terminal in Barranquilla, a distance of approximately 1,500 kilometers, (4) from the Garibay field to facilities at Vasconia Station, a distance of approximately 640 kilometers and (5) during 2012, from the Costayaco field to our short-term customer's facilities at Rio Loro Station, approximately 220 kilometers north of the field.

Oil prices for sales to Ecopetrol are defined by agreements with Ecopetrol based on a "marker" price (generally the average export price for crude oil from the port of shipment) with adjustments for quality and specified fees depending on the port, including a port operation fee and a commercialization fee, and a transportation fee and transportation tax. Oil prices for sales to Gunvor are based on the average of WTI prices plus a Vasconia differential and premium, adjusted for trucking costs. Oil prices for sales to Petrobras Colombia are based on Vasconia crude oil price less adjustments for quality, transportation, marketing and handling. Oil prices for sales to our additional short-term purchaser are determined based on Vasconia crude oil price less adjustments for quality, transportation, marketing and handling. We receive revenues for our Colombian oil sales in U.S. dollars.

Argentina

We market our own share of production in Argentina. The purchaser of our oil in the Noroeste Basin of Argentina is Refinería del Norte S.A. ("Refinor"). Our contract with Refinor expired on January 1, 2008; however, we are continuing sales of our oil under monthly agreements with Refinor. In the Noroeste Basin, oil is delivered to the refinery by truck.

At December 31, 2012, Shell C.A.P.S.A. ("Shell") and YPF S.A. ("YPF") were the main purchasers of our oil in the Neuquen Basin of Argentina. In the Neuquen Basin, oil is delivered to the refinery by pipeline.

Sales to Refinor and Shell accounted for 6% and 3%, respectively, of our oil and natural gas sales in 2012. Sales to Refinor and Shell each accounted for 3% of our oil and natural gas sales in 2011 and sales to Refinor accounted for 4% of our oil and natural gas sales in 2010. The purchaser of our gas in Argentina is Albanesi S.A. Sales to Albanesi S.A. accounted for less than 1% of our oil and natural gas sales in 2012 and 2011 and were nil in 2010.

In Argentina, export prices for oil are subject to an export withholding tax based on WTI price. This export tax has the effect of limiting the actual realized price for sales. Our oil prices are agreed on a spot basis, based on WTI price less adjustments for quality, transportation and an adjustment similar to the export tax. We receive revenues in Argentina pesos, based on U.S. dollar prices at the exchange rate on the payment date.

Brazil

Petróleo Brasileiro S.A (“Petrobras”) is the purchaser of most of the oil produced from Block 155 in Brazil. Oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. During 2012, oil prices for sales to Petrobras were based on the monthly average Brent DTD price less \$11.15 per barrel. Pursuant to the 2013 oil sales contract with Petrobras, oil prices will be based on the monthly average Brent DTD price less \$13.19 per barrel.

There were no sales in any countries other than Colombia, Argentina and Brazil in 2012, 2011 and 2010.

See “Guerrilla Activity in Colombia Has Disrupted and Delayed, and Could Continue to Disrupt or Delay, Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Colombia”, “Our Oil Sales Will Depend on a Relatively Small Group of Customers, Which Could Adversely Affect Our Financial Results,” and “Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations”, “Negative Political Developments in Peru May Negatively Affect our Proposed Operations,” “Our Business is Subject to Local Legal, Political and Economic Factors Which are Beyond Our Control, Which Could Impair Our Ability to Expand Our Operations or Operate Profitably” and other risk factors in Item 1A “Risk Factors” for a description of the risks faced by our dependency on a small number of customers and the regulatory systems under which we operate.

Competition

The oil and gas industry is highly competitive. We face competition from both local and international companies in acquiring properties, contracting for drilling and other oil field equipment and securing trained personnel. Many of these competitors have financial and technical resources that exceed ours, and we believe that these companies have a competitive advantage in these areas. Others are smaller, and we believe our technical and financial capabilities give us a competitive advantage over these companies. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for prospects and resources in the oil and gas industry.

See “Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business” in Item 1A “Risk Factors” for risks associated with competition.

Geographic Information

Information regarding our geographic segments, including information on revenues, assets, expenses, and net income can be found in Note 4 to the Financial Statements, Segment and Geographic Reporting, in Item 8 “Financial Statements and Supplementary Data”, which information is incorporated by reference here. Long lived assets are Property, Plant and Equipment, which includes all oil and gas assets, furniture and fixtures, automobiles and computer equipment. No long lived assets are held in our country of domicile, which is the United States of America. ‘All Other’ assets include assets held by our corporate head office in Calgary, Alberta, Canada. Because all of our exploration and development operations are in South America, we face many risks attendant with these operations. See Item 1A “Risk Factors” for risks associated with our foreign operations.

Regulation

The oil and gas industry in Colombia, Argentina, Peru and Brazil is heavily regulated. Rights and obligations with regard to exploration, development and production activities are explicit for each project; economics are governed by a royalty/tax regime. Various government approvals are required for property acquisitions and transfers, including, but not limited to, meeting financial and technical qualification criteria in order to be certified as an oil and gas company in the country. Oil and gas concessions are typically granted for fixed terms with opportunity for extension.

Colombia

In Colombia, prior to 2004, Ecopetrol was the administrator of all hydrocarbons and therefore executed contracts with oil companies under different contractual types such as Association Contracts and Shared Risk Contracts. Under Association Contracts, the oil companies (“Associate”) assumed all risk during the exploration phase and Ecopetrol had the obligation to reimburse to the Associate, after the commerciality was accepted by Ecopetrol, the direct exploration costs which the Associate incurred in proportion to Ecopetrol's working interest. If Ecopetrol did not accept the initial commerciality of a field, the Associate could continue the activities at its sole risk and Ecopetrol would retain the right to back-in later, after Ecopetrol reimbursed the Associate for the initial exploitation work and exploration costs plus certain penalties, depending upon at what stage Ecopetrol later declared commerciality of the field.

Effective June 2003, the regulatory regime in Colombia underwent a significant change with the formation of the ANH. The ANH is now the administrator of the hydrocarbons in the country and therefore is responsible for regulating the Colombian oil and gas industry, including managing all exploration lands. Ecopetrol became a public company owned in majority by the state with the main purpose of exploring and producing hydrocarbons similar to any other oil company. However, Ecopetrol continues to have rights under the existing contracts executed with oil companies before ANH was created. Ecopetrol continues to be the major purchaser and marketer of oil in Colombia, and also operates the majority of the oil transportation infrastructure in the country.

In conjunction with this change, the ANH developed a new exploration risk contract that took effect as of June 2004. This Exploration and Production Contract has significantly changed the way the industry views Colombia. In place of the earlier association contracts, the new agreement provides full risk/reward benefits for the contractor. Under the terms of the contract the successful operator retains the rights to all reserves, production and income from any new exploration block, subject to existing royalty and tax regulations. Each contract contains an exploration phase and a production phase. The exploration phase will contain a number of exploration periods and each period will have an associated work commitment. The production phase will last a number of years (usually 24) from the declaration of a commercial hydrocarbon discovery.

Gran Tierra operates in Colombia through two branches – Gran Tierra Energy Colombia, Ltd. and Petrolifera Petroleum (Colombia) Limited. Both are qualified as operators of oil and gas properties by ANH.

When operating under a contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, and pays royalties which are collected by ANH or Ecopetrol, depending on the type of contract. The contractor can market the hydrocarbons in any manner whatsoever, subject to a limitation in the case of natural emergencies where the law specifies the manner of sale.

Argentina

The Hydrocarbons Law 17.319, enacted in June 1967, established the basic legal framework for the regulation of exploration and production of hydrocarbons in Argentina. The Hydrocarbons Law empowers the National Executive Branch to establish a national policy for development of Argentina's hydrocarbon reserves, with the main purpose of satisfying domestic demand. However, on January 5, 2007, Law 26.197 was passed by the Government of Argentina. This legal framework replaced article one of the Hydrocarbons Law 17.319 and provides for the provinces to assume complete ownership, authority and administration of the oil and natural gas reserves located within their territories, including offshore areas up to 12 marine miles from the coast line. This includes all exploration permits and exploitation and transportation concessions.

On June 3, 2002, the Government of Argentina issued a resolution authorizing the Energy Secretariat to limit the amount of oil that companies can export. The restriction was to be in place from June 2002 to September 2002. However, on June 14, 2002, the government agreed to abandon the limit on oil export volumes in exchange for a guarantee from oil companies that domestic demand will be supplied. Oil companies also agreed not to raise natural gas and related prices to residential customers during the winter months and to maintain gasoline, natural gas and oil prices in line with those in other South American countries.

Near the end of 2007, the Government of Argentina issued decrees changing the withholding export tax structure and further regulating oil exports.

At the end of 2008, the Argentina government launched the Gas Plus and Petroleum Plus programs, programs designed to stimulate investments in and production of natural gas and oil through providing incentives for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields. Companies must apply for the incentives, and qualification is based on a complex set of formulas involving increased production over a calculated base and increases in proved reserves for the year. Gran Tierra has received credits totaling \$2.6 million under the Petroleum Plus program related to our production for the first, third and fourth quarters of 2010 and the first quarter of 2008. Claims are pending for certain other quarters in 2011, 2010 and 2009. Realization of the credits is contingent on Gran Tierra establishing a contract with a third party to purchase the credits or exporting oil. We are negotiating with other parties for the sale of other credits.

In October 2010, the Argentina Gas Authority ("ENARGAS") issued Regulation I-1410 aimed at securing the supply of natural gas to residential consumers and small industry given the decline in gas production and the expected growing demand for gas. The regulation includes all the procedures created by the authorities since 2004 (restrictions of exports, deviation of gas sales to residential consumption) and gives ENARGAS power to control gas marketing in order to assure the supply of gas to residential consumers and small industry. This regulation is being challenged by gas producers on the grounds that it illegally interferes in their gas marketing activities.

After general elections in October 2011, the Government of Argentina decided to remove certain subsidies which were implemented after the 2001/2002 Argentina economic crisis. Consequently, in November 2011, ENARGAS issued Regulation 1982 which broadened the application of a charge to certain industries and services, including oil & gas upstream and natural gas processing activities, and increased the charge. The charge was created in 2008 to fund the importation of natural gas and liquefied natural gas into Argentina. This measure is expected to negatively impact the oil and gas industry in Argentina and has been challenged by some important companies within the industry.

In July 2012, the Argentina government mandated the creation of an oil planning commission that will set national energy goals and have the power to review private oil companies' investment plans. Private companies must submit an annual investment plan by September 30 of each year. The committee will have the power to approve or reject the annual investment plan. This decree is new and many details are yet to be announced. However, we believe there is a risk that this may cause delays in our operations in Argentina, or cause changes to our investment plans that could negatively affect our business in Argentina or the rest of our operations.

Additionally in Argentina some provincial regulations are changing, introducing new royalties and fees associated with extensions of concession agreements.

Gran Tierra operates in Argentina through Gran Tierra Energy Argentina S.R.L. and two branches: Petrolifera Petroleum (Americas) Limited - Sucursal Argentina and Petrolifera Petroleum Limited - Sucursal Argentina. Gran Tierra Energy Argentina S.R.L. and Petrolifera Petroleum (Americas) Limited - Sucursal Argentina are qualified by the Federal Secretary of Energy to be titleholders of Exploration Permits and Exploitation Concessions as well as to operate them. Petrolifera Petroleum Limited - Sucursal Argentina is qualified to be a titleholder of Exploration Permits and Exploitation Concessions, but not to operate them.

See "Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations" in Item 1A "Risk Factors" for a description of the risks associated with Argentina government controls.

Peru

Peru's hydrocarbon legislation, which includes the Organic Hydrocarbon Law No. 26221 enacted in 1993 and the regulations thereunder (the "Organic Hydrocarbon Law"), governs our operations in Peru. This legislation covers the entire range of petroleum operations, defines the roles of Peruvian government agencies which regulate and interact with the oil and gas industry, provides that private investors (either national or foreign) may also make investments in the petroleum sector, and provides for the promotion of the development of hydrocarbon activities based on free competition and free access to all economic activities. This law provides that pipeline transportation and natural gas distribution must be handled via concession contracts with the appropriate governmental authorities. All other petroleum activities are to be freely operated and are subject only to local and international safety and environment standards.

Under the Peruvian legal system, Peru is the owner of the hydrocarbons located below the surface in its national territory. However, Peru has given the ownership right to extracted hydrocarbons to PeruPetro S.A. ("PeruPetro"), a state company responsible for promoting and overseeing the investment of hydrocarbon exploration and exploitation activities in Peru. PeruPetro is empowered to enter into contracts for either the exploration and exploitation or just the exploitation of petroleum and natural gas on behalf of Peru, the nature of which are described further below. The Peruvian government also plays an active role in petroleum operations through the involvement of the Ministry of Energy and Mines, the specialized government department in charge of establishing energy, mining and environmental protection policies, enacting the rules applicable to all these sectors and supervising compliance with such policies and rules. We are subject to the laws and regulations of all of these entities and agencies.

PeruPetro enters into either license contracts or service contracts for hydrocarbon exploration and exploitation. Peruvian law also allows for other contract models, but the investor must propose contract terms compatible with Peru's interests. We only operate under license contracts and do not foresee operating under any services contracts. A company must be qualified by PeruPetro to enter into hydrocarbon exploration and exploitation contracts in Peru. In order to qualify, the company must meet the standards under the Regulations Governing the Qualifications of Oil Companies. These qualifications generally require the company to have the technical, legal, economic and financial capacity to comply with all obligations it will assume under the contract based on the characteristics of the area requested, the possible investments and the environmental protection rules governing the performance of its operations. When a contractor is a foreign investor, it is expected to incorporate a subsidiary company or registered branch in accordance with Peruvian corporate law and appoint Peruvian representatives in accordance with the Organic Hydrocarbon Law who will interact with PeruPetro.

Gran Tierra operates in Peru through Gran Tierra Energy Peru S.R.L. and Petrolifera Petroleum Del Peru S.A.C. Gran Tierra has been qualified by PeruPetro with respect to our contracts for Blocks 95, 123 and 129 and Petrolifera has been qualified by PeruPetro with respect to our contracts for Blocks 107 and 133.

When operating under a license contract, the licensee is the owner of the hydrocarbons extracted from the contract area during the performance of operations, and pays royalties which are collected by PeruPetro. The licensee can market or export the hydrocarbons in any manner whatsoever, subject to a limitation in the case of national emergency where the law stipulates such manner.

See “Negative Political Developments in Peru May Negatively Affect our Proposed Operations” in Item 1A “Risk Factors” for a description of the risks associated with the political climate in Peru.

Brazil

In Brazil, Law No. 2004 enacted in 1953 created the state monopoly of the petroleum industry and Petrobras, a state-owned legal entity, which was the sole company conducting exploration and production activities in Brazil.

Amendment No. 9 to the Brazilian Constitution, enacted on November 9, 1995, authorized the Brazilian government to contract with state and private companies, with head offices and management located in Brazil, for the exploration and production of oil and natural gas, as well as to grant authorizations for the refining, transportation, import and export of oil, natural gas and its by-products, discontinuing Petrobras’ exclusive right to explore and produce petroleum and natural gas in Brazil.

The regulatory model is governed by Law No. 9478 of August 6, 1997 (the “Petroleum Law”), as amended, which controls the granting of concessions for carrying out exploration and production activities to Brazilian companies. The Petroleum Law, as amended, also established a legal framework for pre-salt layer areas and strategic areas to be defined by the Brazilian government and which will be subject to the Production Sharing Regime.

In accordance with the Petroleum Law, the acquisition of oil and natural gas property and oil and gas operations by state and private companies is subject to legal, technical and economic standards and regulations issued by the ANP, the agency created by the Petroleum Law and vested with regulatory and inspection authority to ensure adequate operational procedures with respect to industry activities and the supply of fuels throughout the national territory.

The ANP has authority for the implementation of the national oil and natural gas policy in accordance with the National Council of Energy Policy (“CNPE”). The ANP conducts bid rounds to award exploration, development and production contracts, as well as to approve the construction and operation of refineries and gas processing units, transportation facilities (including port terminals), import and export of oil and natural gas, as well as supervision of the activities which integrate the petroleum industry and the general enforcement of the Petroleum Law.

During a public bid procedure, any company evidencing technical, financial and legal standards under the applicable regulations may qualify and apply for particular blocks made available for concession contracts. Qualified companies may compete alone or in association with other companies, including through the formation of “consortia” (unincorporated joint-ventures), provided they agree to comply with all the applicable requirements of Brazilian Corporate Law. Blocks awarded and the duration of the exploration and production periods are defined in the contracts which, besides the usual covenants that can be found in oil concessions, such as exploration and development programs, relinquishment of areas, and unitization, include reversion to the state of certain assets at the end of the concession. Contracts may be assigned or transferred to other Brazilian companies that comply with the technical, financial and legal requirements established by ANP.

Oil and natural gas resources in Brazil, whether onshore or offshore, belong to the Brazilian government. However, under the Concession Regime, after the discovery of oil and gas reserves, ownership is assigned to the concessionaire. Under the principles of the Federal Constitution the national territory comprises all land and the continental shelf. Brazil is a signatory of the conventions regulating the economic use of the sea and its subsoil. Brazil is thus entitled to the enjoyment of the resources over the territorial sea and marine platform up to the limits indicated in the pertinent treaties.

Concessionaires are required under Law No. 9478 to pay the government dues and fees, in addition to the charges for sale of pre-bid data and information. ANP has the power to determine the criteria under which the Government Take will be assessed within the limits established by Decree No. 2,705/98. Government Take comprises (i) signature bonus, (ii) royalties, (iii) special participation and (iv) area rentals. Part of the Government Take is passed on to States and Municipalities and other government branches according to law.

Gran Tierra operates in Brazil through Gran Tierra Energy Brasil Ltda. (“Gran Tierra Brazil”). Gran Tierra Brazil received approval from the ANP as a Class B operator permitting Grant Tierra Brazil to act as an operator both onshore and in the shallow water offshore Brazil.

See Item 1A “Risk Factors” for information regarding the regulatory risks that we face.

Environmental Compliance

Our activities are subject to existing laws and regulations governing environmental quality and pollution control in the foreign countries where we maintain operations. Our activities with respect to exploration, drilling and production from wells, facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil and other products, are subject to stringent environmental regulation by provincial and federal authorities in Colombia, Argentina, Peru and Brazil. Such regulations relate to environmental impact studies, permissible levels of air and water emissions, control of hazardous wastes, construction of facilities, recycling requirements, reclamation standards, among others. Risks are inherent in oil and gas exploration, development and production operations, and significant costs and liabilities may be incurred in connection with environmental compliance issues. All licenses and permits which we may require to carry out exploration and production activities may not be obtainable on reasonable terms or on a timely basis, and such laws and regulations may have an adverse effect on any project that we may wish to undertake.

In 2013, we plan to spend approximately \$12.0 million in Colombia on capital programs related to environmental studies, community consultations and environmental remediation. In Peru, costs for environmental and social projects are expected to be approximately \$6.0 million which mainly relates to environmental and social impact assessments, implementation of environmental management plans, and environmental and social monitoring activities. We plan to spend approximately \$1.2 million in Argentina on programs related to environmental matters, including environmental studies, water treatment and chemical storage facilities. In Brazil, we plan to spend approximately \$0.9 million on costs for environmental projects.

In 2012, we experienced a limited number of environmental incidents and enacted the following environmental initiatives:

- In Colombia, oil was released from a flow through drainage chamber in the Mary battery. We have taken measures to contain the release, are continuing to investigate the source of the release and plan to start remediation activities. The remainder related to the integrity of materials, the rollover of two oil transportation trucks and the installation of illegal valves. A number of minor incidents on our blocks occurred, each of which caused small quantities of oil to be spilled. In each of these minor incidents, we completed a full clean up and remediation of the affected area.
- In Argentina, minor spills occurred relating to pipeline corrosion, an overflowing storage tank and other incidents. In each case, we completed a full clean up and remediation of the affected area.
- In Peru, we continued the Environmental Monitoring Program for drilling activity on Block 95 and pursued an agreement with the Pacaya Samiria Natural Reserve. We are also seeking the necessary permits for the relocation of four well pads and a seismic project in Block 107 and we began preparations for an Environmental Impact Study for seismic and drilling activities on Block 133.
- In Brazil, we obtained the necessary licenses for pipelines to connect our wells on Block 155 and are developing a water, soil and air monitoring program.

We will continue to strive to be in compliance with all environmental and pollution control laws and regulations in Colombia, Argentina, Peru and Brazil. We plan to continue enacting environmental, health and safety initiatives in order to minimize our environmental impact and expenses. We also plan to continue to improve internal audit procedures and practices in order to monitor current performance and search for improvement.

We expect the cost of compliance with federal, state and local provisions which have been enacted or adopted regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment for the remainder of our operations, will not be material to Gran Tierra.

We have implemented a company wide web based reporting system which allows us to better track incidents and respective corrective actions and associated costs. We have a Corporate Health, Safety and Environment Management System and follow Environmental Best Practices. We have an environmental risk management program in place as well as a waste management system. Air and water testing occur regularly, and environmental contingency plans have been prepared for all sites and ground transportation of oil. We have a regular quarterly comprehensive reporting system, with a schedule of internal audit and routine checking of practices and procedures. Emergency response exercises were conducted in Calgary, Argentina, Colombia, Peru and Brazil.

Community Relation Initiatives

In 2012, we continued standardized, quarterly reporting on our community relation initiatives. We also continuously monitor the needs of the communities where we operate to ensure that our investments meet their requirements and have the highest impact possible.

In addition to employing local people and hiring local companies as often as feasible in all of our operations, we have a program of community investment in all of our operating areas. Projects undertaken in 2012 were as follows:

Colombia

In 2012, our most significant community relations initiatives and investments were made in the Costayaco, Moqueta, Santana and Guayuyaco fields. We made voluntary investments in relation to community support during drilling projects on the Chaza, Sierra Nevada, Turpial, Azar, and Guepaje Blocks during the year and during the Rumiayaco 3-D seismic project. Below is a description of our \$2.3 million voluntary social investment, responding to the needs identified and prioritized by the communities in those areas in which we operate.

- Provided support for education, including providing tuition, supplies and transportation for students in all levels of education.
- Supported community groups in projects that benefited local families with agriculture and fisheries projects.
- Provided fiscal support, construction of facilities, transportation of materials and other expertise to projects.
- Various projects for the support of cultural identity such as sponsorship of local festivals that celebrate indigenous culture and history and sponsorship of local people to attend a conference of indigenous peoples from various areas in the country.
- Various programs for strengthening local infrastructure such as paving streets in urban areas, construction of culture rooms, fencing at schools, construction of sport facilities and computer rooms, and provision of materials for electric power supply in rural areas.
- Projects related to health, basic sanitation and housing including improving health facilities, health brigades, and remodeling and equipment of health centers.
- Provided strong communications with the communities and undertook prior consultations with ethnic minorities.

Argentina

In 2012, we invested approximately \$0.6 million in the following activities:

- Provided and distributed education materials to schools in our operated areas and ran health and environment workshops with students.
- Created school vegetable gardens and chaguar experimental farming
- Provided training to teachers and students in health education.
- Provided basic life necessities (food, clothing, health support) to impoverished people in our operating areas.
- Delivered medicines to hospitals and supported medical care of children and pregnant women.

- Provided temporary employment to residents in several of our operating areas.
- Provided funds in support of beekeeping and crafts projects.
- Provided cattle guards to the landowners.
- Delivered drinking water to nearby families.
- Along with our joint venture partners in the Palmar Largo Block, several other initiatives were undertaken, including projects aimed at developing sustainable income for the communities in the area, fuel and security for local hospitals, and construction of reservoirs and water wells. These projects were operated by PlusPetrol S.A.
- A social survey was carried out in the Neuquen Basin in order to implement a social and community relations program. The program is expected to start during the first quarter 2013.

Peru

In 2012, we invested approximately \$1.9 million in the following activities:

- Negotiated compensation arrangements with communities for the use of their lands. In Block 95, executed an agreement with the Breña town to improve electricity services and the health center.
- Held consultation and education sessions with various communities located on our blocks and developed technical workshops with indigenous organizations on the uses of natural resources.
- Provided healthcare support services to communities in our blocks.
- Provided temporary employment to residents in our blocks.

Brazil

In 2012, we invested approximately \$150,000 in a compensation program with communities for use of their lands. We began work on landowner agreements and negotiated payments for carrying out seismic programs on their land. We completed the evaluation and development of a Corporate Social Responsibility (“CSR”) project in the Pojuca Area. We completed an assessment of social initiatives and communities’ needs, as well as stakeholder’s strengths, in municipalities around Block 155. We developed and implemented the program “birds of my land” where children of the community named our Tiê field. We also undertook work to improve waste transportation.

Employees

At December 31, 2012, we had 485 full-time employees: 44 located in the Calgary corporate office, 275 in Colombia (137 staff in Bogota and 138 field personnel), 89 in Argentina (46 office staff in Buenos Aires and 43 field personnel, of which 26 were unionized), 44 in Peru (both field and office staff) and 33 in Brazil (21 office staff in Rio de Janeiro and Salvador and 12 field staff). Other than as disclosed above, none of our employees are represented by labor unions, and we consider our employee relations to be good.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Exchange Act which we make available as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC, are available free of charge to the public on our website www.grantierra.com. To access our SEC filings, select SEC Filings from the investor relations menu on our website, which will provide a list of our SEC filings. Our website address is provided solely for informational purposes. We do not intend, by this reference, that our website should be deemed to be part of this Annual Report. Any materials we have filed with the SEC may be read and/or copied at the SEC's Public Reference Room at 100 F Street N.E. Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding us. Our SEC filings are also available to the public at the SEC's website at www.SEC.gov.

Item 1A. Risk Factors

Risks Related to Our Business

Guerrilla Activity in Colombia Has Disrupted and Delayed, and Could Continue to Disrupt or Delay, Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Colombia.

During 2012, the guerrilla activity in Colombia has increased significantly. This increased activity creates a greater risk for our operations and our employees and our mitigation activities may not be adequate to alleviate the risks arising from such guerrilla activity.

For over 40 years, the Colombian government has been engaged in a civil war with two main Marxist guerrilla groups: the Revolutionary Armed Forces of Colombia ("FARC") and the National Liberation Army ("ELN"). Both of these groups have been designated as terrorist organizations by the United States and the European Union. Another threat comes from criminal gangs formed from the former members of the United Self-Defense Forces of Colombia ("AUC") militia, a paramilitary group that originally sprouted up to combat FARC and ELN, which the Colombian government successfully dissolved.

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Catatumbo, Cauca, Llanos, Middle Magdalena and Lower Magdalena Basins. The Putumayo and Catatumbo regions have been the breeding place of guerrilla activity. Beginning in 1989, our predecessor company's facilities in one field were attacked by guerrillas and operations were briefly disrupted. In October 2010, two of our sites in the Putumayo/Cauca were attacked by FARC guerrillas causing some disruption to operations. Pipelines have also been primary targets because such pipelines cannot be adequately secured due to the sheer size of such pipelines and the remoteness of the areas in which the pipelines are laid. The Ecopetrol-operated OTA pipeline which transports oil from the Putumayo region and upon which we materially rely has been a target by these guerrilla groups. In March and April of 2008, June, July, August and October of 2009, June, August, and September of 2010, February 2011, February to August of 2012 and October 2012 to February 2013, sections of the OTA pipeline were sabotaged by guerrillas, which temporarily reduced our deliveries to Ecopetrol during the affected periods. In the year ended December 31, 2012, the OTA pipeline was shutdown for over 162 days and the shutdown has had a material adverse effect on our deliveries to Ecopetrol and our financial performance for 2012. We have employed mitigation strategies as discussed in the risk "*We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses*" later in this section. Such disruptions may continue indefinitely and could harm our business.

On January 30, 2013, four contract workers employed by companies providing services to Gran Tierra in the Putumayo Basin were abducted, possibly by guerrillas. One individual was released within an hour, the other three contractor workers were returned unharmed the next day (January 31, 2013). No employees of Gran Tierra were involved in the incident. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

Our Lack of Diversification Will Increase the Risk of an Investment in Our Common Stock.

Our business focuses on the oil and gas industry in a limited number of properties in Colombia, Argentina, Peru, and Brazil. Most of our production is in one basin in Colombia and two basins in Argentina. As a result, we lack diversification, in terms of both the nature and geographic scope of our business. Accordingly, factors affecting our industry or the regions in which we operate, including the geographic remoteness of our operations and weather conditions, will likely impact us more acutely than if our business was more diversified. In particular, most of our production is from the Putumayo Basin in Colombia, and we depend on the OTA pipeline to transport our oil to market. Cash flow from these sales funds a large part of our business. Disruptions to this pipeline, as described in the risk "We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses" could harm our business in Colombia and other countries.

We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses.

To sell the oil and natural gas that we are able to produce, we have to make arrangements for storage and distribution to the market. We rely on local infrastructure and the availability of transportation for storage and shipment of our products, but infrastructure development and storage and transportation facilities may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. This could be particularly problematic to the extent that our operations are conducted in remote areas that are difficult to access, such as areas that are distant from shipping and/or pipeline facilities. In certain areas, we may be required to rely on only one gathering system, trucking company or pipeline, and, if so, our ability to market our production would be subject to their reliability and operations. These factors may affect our ability to explore and develop properties and to store and transport our oil and gas production, and may increase our expenses. Furthermore, future instability in one or more of the countries in which we operate, weather conditions or natural disasters, actions by companies doing business in those countries, labor disputes or actions taken by the international community may impair the distribution of oil and/or natural gas and in turn diminish our financial condition or ability to maintain our operations.

The majority of our oil in Colombia is delivered by a single pipeline to Ecopetrol and sales of oil have been and could continue to be disrupted by damage to this pipeline or displaced by Ecopetrol's use of the pipeline itself. Starting in February 2012, we are operating under a new transportation contract with Ecopetrol which changes the point at which Ecopetrol takes delivery of our oil. Previously, Ecopetrol took delivery of our oil at the beginning of the export pipeline. Under the new transportation contract, Ecopetrol takes delivery at the end of the export pipeline. This creates a risk of loss of oil due to sabotage by guerrillas or theft from the pipeline which may result in reduced revenues and increased clean-up or third party costs. We have attempted to mitigate the risk of increased costs with insurance and are investigating potential ways to mitigate and reduce revenue risk. Ecopetrol maintains responsibility for clean-up of any spilled oil and for pipeline repair.

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, June, July and August of 2009, June, August, and September 2010, February 2011, February to August of 2012 and October 2012 to February 2013 as a result of sabotage by guerrillas. In addition, there is competition for space in these pipelines, and additional discoveries in our area of operations by other companies could decrease the pipeline capacity available to us. Trucking is an alternative to transportation by pipeline; however, it is generally more expensive and carries higher safety risks for us, our employees and the public.

As some of our oil production in Argentina is trucked to a local refinery, sales of oil in the Noroeste Basin can be delayed by adverse weather and road conditions, particularly during the months November through February when the area is subject to periods of heavy rain and flooding. While storage facilities are designed to accommodate ordinary disruptions without curtailing production, delayed sales will delay revenues and may adversely impact our working capital position in Argentina. Furthermore, a prolonged disruption in oil deliveries could exceed storage capacities and shut-in production, which could have a negative impact on future production capability.

Recent alternative transportation arrangements in Colombia allowed us to deliver our full production in January 2013; however, these deliveries carried higher transportation costs than the Ecopetrol operated OTA pipeline transportation costs and are not necessarily sustainable. When disruptions are of a long enough duration, our sales volumes may be lower than normal, which will cause our cash flow to be lower than normal, and if our storage facilities become full, we can be forced to reduce production.

Our Oil Sales Will Depend on a Relatively Small Group of Customers, Which Could Adversely Affect Our Financial Results.

Oil sales in Colombia are mainly to Ecopetrol. While oil prices in Colombia are related to international market prices, lack of competition and reliance on a limited number of customers for sales of oil may diminish prices and depress our financial results.

The entire Argentina domestic refining market is small and export opportunities are limited by available infrastructure. As a result, our oil and gas sales in Argentina will depend on a relatively small group of customers, and currently, on two significant customers. The lack of competition in this market could result in unfavorable sales terms which, in turn, could adversely affect our financial results. Currently, all operators in Argentina are operating without long-term sales contracts. We cannot provide any certainty as to when the situation will be resolved or what the final outcome will be.

In Brazil, there are a number of potential customers for our oil, and we are working to establish relationships with as many as possible to ensure a stable market for our oil. Currently, essentially all of our production in Brazil is sold to Petróleo Brasileiro S.A. (“Petrobras”). Petrobras’ refinery in the area of our operations has had some technical difficulties which have restricted its ability to receive deliveries. Our second option in the area is at full capacity. This could mean that we cannot produce to full capacity in the area because of restrictions in being able to deliver our oil.

Our Business is Subject to Local Legal, Political and Economic Factors Which are Beyond Our Control, Which Could Impair Our Ability to Expand Our Operations or Operate Profitably.

We operate our business in Colombia, Argentina, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as privatization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. For example, starting on November 21, 2008, we were forced to reduce production in Colombia on a gradual basis, culminating on December 11, 2008, when we suspended all production from the Santana, Guayuyaco and Chaza blocks in the Putumayo Basin. This temporary suspension of production operations was the result of a declaration of a state of emergency and force majeure by Ecopetrol due to a general strike in the region. In January 2009, the situation was resolved and we were able to resume production and sales shipments. Starting in 2010, there was an increased presence of illegitimate unionization activities in the Putumayo Basin by the *Sindicato de Trabajadores Petroleros del Putumayo*, which disrupted our operations from time to time and may do so in the future. During 2012 and 2011, Argentina has experienced increased union activity and this may create disruptions in our Argentina operations in the future. During 2012 and 2013, we have also experienced related issues with landowners blocking access to our fields for short periods of time in Argentina. South America has a history of political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including the imposition of additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Argentina, Colombia, Peru or Brazil or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

For instance, changes in laws in the jurisdiction in which we operate or expand into with the effect of favoring local enterprises, and changes in political views regarding the exploitation of natural resources and economic pressures, may make it more difficult for us to negotiate agreements on favorable terms, obtain required licenses, comply with regulations or effectively adapt to adverse economic changes, such as increased taxes, higher costs, inflationary pressure and currency fluctuations. In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for business. These licenses and agreements may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired.

In July 2012, the Argentina government mandated the creation of an oil planning commission that will set national energy goals and have the power to review private oil companies' investment plans. Private companies must submit an annual investment plan by September 30 of each year. The committee will have the power to approve or reject the annual investment plan. This decree is new and many details are yet to be announced. However, we believe there is a risk that this may cause delays in our operations in Argentina, or cause changes to our investment plans that could negatively affect our business in Argentina or the rest of our operations.

Additionally in Argentina, some provincial regulations are changing, introducing new royalties and fees associated with extensions of concession agreements. These royalties and fees represent increased costs for the affected concessions, specifically our Rio Negro Province concession, which could result in a decreased rate of return from this asset and could negatively affect our business in Argentina.

We Have an Aggressive Business Plan, and if we do not Have the Resources to Execute on our Business Plan, We May Be Required to Curtail Our Operations.

Our capital program for 2013 calls for approximately \$363 million to fund our exploration and development, which we intend to fund through existing cash, cash flows from operations and potential periodic draws from our revolving credit facility. Funding this program relies in part on oil prices remaining high and other factors to generate sufficient cash flow. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our business plan which would cause us to decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

Strategic and Business Relationships upon Which We May Rely are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.

Our ability to successfully bid on and acquire additional properties, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements will depend on developing and maintaining effective working relationships with industry participants and on our ability to select and evaluate suitable partners and to consummate transactions in a highly competitive environment. These relationships are subject to change and may impair our ability to grow.

To develop our business, we endeavor to use the business relationships of our management and board of directors to enter into strategic and business relationships, which may take the form of joint ventures with other parties or with local government bodies, or contractual arrangements with other oil and gas companies, including those that supply equipment and other resources that we will use in our business. We also have an active business development program to develop those relationships and foster new relationships. We may not be able to establish these business relationships, or if established, we may choose the wrong partner or we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to take to fulfill our obligations to these partners or maintain our relationships. If we fail to make the cash calls required by our joint venture partners in the joint ventures we do not operate, we may be required to forfeit our interests in these joint ventures. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

In addition, in cases where we are the operator, our partners may not be able to fulfill their obligations, which would require us to either take on their obligations in addition to our own, or possibly forfeit our rights to the area involved in the joint venture. In addition, despite our partner's failure to fulfill its obligations, if we elect to terminate such relationship, we may be involved in litigation with such partners or may be required to pay amounts in settlement to avoid litigation despite such partner's failure to perform. Alternatively, our partners may be able to fulfill their obligations, but will not agree with our proposals as operator of the property. In this case there could be disagreements between joint venture partners that could be costly in terms of dollars, time, deterioration of the partner relationship, and/or our reputation as a reputable operator. These joint venture partners may not comply with their responsibilities or may engage in conduct that could result in liability to us.

In cases where we are not the operator of the joint venture, the success of the projects held under these joint ventures is substantially dependent on our joint venture partners. The operator is responsible for day-to-day operations, safety, environmental compliance and relationships with government and vendors.

We have various work obligations on our blocks that must be fulfilled or we could face penalties, or lose our rights to those blocks if we do not fulfill our work obligations. Failure to fulfill obligations in one block can also have implications on the ability to operate other blocks in the country ranging from delays in government process and procedure to loss of rights in other blocks or in the country as a whole. Failure to meet obligations in one particular country may also have an impact on our ability to operate in others.

Disputes or Uncertainties May Arise in Relation to our Royalty Obligations

Our production is subject to royalty obligations which may be prescribed by government regulation or by contract. These royalty obligations may be subject to changes in interpretation as business circumstances change.

In accordance with our Hydrocarbon Exploration and Exploitation Agreement with ANH for the Chaza Block in Colombia our oil production from each Exploitation Area on the Block is subject to the payment of additional compensation to the ANH over and above the basic sliding scale royalty that applies when cumulative gross production from an Exploitation Area exceeds five MMbbl. Production from the Costayaco Exploitation Area on the Chaza Block became subject to this additional compensation in the fourth quarter of 2009 after cumulative production from the Costayaco field exceeded five MMbbl.

The ANH has requested that the additional compensation be paid with respect to production from the recently drilled wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, we view the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have sent notice to the ANH to initiate the dispute resolution process prescribed by the Chaza Contract. No assurance can be made that our interpretation will prevail and, depending on the ultimate size of the cumulative production from the Moqueta field in the future, such amounts may be material if such additional compensation must be paid. As at December 31, 2012, total cumulative production from the Moqueta field was 0.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is \$15.1 million. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed royalty as Gran Tierra does not consider it probable that a loss will be incurred.

In Brazil, a new regulatory regime was introduced; however, the royalty distribution between producing states has not been approved.

Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations.

The oil and natural gas industry in Argentina is subject to extensive regulation including land tenure, exploration, development, production, refining, transportation, and marketing, imposed by legislation enacted by various levels of government and, with respect to pricing and taxation of oil and natural gas, by agreements among the federal and provincial governments, all of which are subject to change and could have a material impact on our business in Argentina. The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on oil and natural gas exports.

In October 2010, ENARGAS issued Regulation I-1410 aiming at securing the supply of natural gas to residential consumers and small industry given the decline in gas production and the expected growing demand for gas. The regulation includes all the procedures created by the authorities since 2004 (restrictions of exports, deviation of gas sales, to residential consumption) and gives ENARGAS power to control gas marketing in order to assure the supply of gas to residential consumers and small industry.

Any future regulations that limit the amount of oil and gas that we could sell or any regulations that limit price increases in Argentina and elsewhere could severely limit the amount of our revenue and affect our results of operations.

Currently most oil and gas producers in Argentina are operating without sales contracts. In 2008, a new withholding tax regime for exports was introduced without specific guidance as to its application. The domestic price was regulated in a similar way, so that both exported and domestically sold products were priced the same. Producers and refiners of oil in Argentina were unable to determine an agreed sales price for oil deliveries to refineries. In our case, the refineries' price offered to oil producers reflects their price received, less taxes and operating costs and their usual mark up. Along with most other oil producers in Argentina, we are continuing negotiating sales on a spot price basis with refiners and the price is negotiated on a month by month basis. The Provincial governments have also been hurt by these changes as their effective royalty and turnover tax takes have been reduced and capital investment in oilfields has declined, and so they are lobbying to change the situation. The government introduced the Petro Plus and Gas Plus programs in 2009, which grant higher prices to producers that sell production from new reserves. This is a positive step forward that will hopefully lead to further opening of price regulation in Argentina.

Recently, the government of Argentina has been active in the oil and gas business. On April 16, 2012, the government announced their intention to acquire a 51% interest in YPF S.A. ("YPF") from Repsol S.A. (Repsol S.A. holds 56.7% of YPF), and retain 51% control for the Federal Government and distribute 49% of the shares to Argentina provinces. During 2012, the Argentina government took control of YPF's operations and signed deals with Chevron Corporation and others for developing shale resources. Repsol S.A. has filed international complaints and US lawsuits regarding the takeover and subsequent deals. Prior to this announcement, various provincial governments announced contract cancellations effecting YPF, Petrobras Argentina S.A., and Azabache Energy Inc., among others. The reason cited for the contract cancellations was lack of activity in the areas in question. We have experienced recent success in Argentina and have active programs in all areas, which we believe helps mitigate our risk. However, despite the fact that our operating entity in Argentina is a locally incorporated company the employees of which are all Argentine, we are viewed as a foreign company and could therefore face increased risk.

In July 2012, the Argentina government mandated the creation of an oil planning commission that will set national energy goals and have the power to review private oil companies' investment plans. The committee will have the power to approve or reject annual investment plans that must be submitted by private companies by September 30 of each year. This decree is new and many details are yet to be announced. However, we believe there is a risk that this may cause delays in our operations in Argentina, or cause changes to our investment plans that could negatively effect our business in Argentina or the rest of our operations.

Additionally in Argentina some provincial regulations are changing, which are introducing new royalties and fees associated with extensions of concession agreements. These royalties and fees represent increased costs for the affected concessions, specifically our Rio Negro Province concession, which could result in decreased rates of returns from this asset.

Our Business May Suffer If We Do Not Attract and Retain Talented Personnel.

Our success will depend in large measure on the abilities, expertise, judgment, discretion, integrity and good faith of our executive team and other personnel in conducting our business. The loss of any of these individuals or our inability to attract suitably qualified individuals to replace any of them could materially adversely impact our business. We are experiencing difficulties in finding and retaining suitably qualified staff in certain jurisdictions, particularly in Brazil and Peru, where experienced personnel in our industry are in high demand and competition for their talents is intense.

Our success depends on the ability of our management and employees to interpret market and geological data successfully and to interpret and respond to economic, market and other business conditions to locate and adopt appropriate investment opportunities, monitor such investments and ultimately, if required, successfully divest such investments. Further, our key personnel may not continue their association or employment with us and we may not be able to find replacement personnel with comparable skills. If we are unable to attract and retain key personnel, our business may be adversely affected.

Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business.

The oil and gas industry is highly competitive. Other oil and gas companies will compete with us by bidding for exploration and production licenses and other properties and services we will need to operate our business in the countries in which we expect to operate. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies, which, in particular, may have access to greater resources than us, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. In the event that we do not succeed in negotiating additional property acquisitions, our future prospects will likely be substantially limited, and our financial condition and results of operations may deteriorate.

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. Our production in Argentina is primarily invoiced in U.S. dollars, but payment is made in Argentina pesos, at the then current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Since we began operating in Argentina (September 1, 2005), the rate of exchange between the Argentina peso and U.S. dollar has varied between 3.05 pesos to one U.S. dollar to 4.92 pesos to the U.S. dollar, a fluctuation of approximately 61%. Production in Brazil is invoiced and paid in Brazilian Reals. Since September 1, 2005, the exchange rate of the Brazilian Real has varied between 1.56 Reals to one U.S. dollar to 2.45 Reals to the U.S. dollar, a variance of 57%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the strengthening of 9.0% in the Colombian Peso against the U.S. dollar in the year ended December 31, 2012, resulted in a foreign exchange loss.

Exchange Controls and New Taxes Could Materially Affect our Ability to Fund Our Operations and Realize Profits from Our Foreign Operations.

Foreign operations may require funding if their cash requirements exceed operating cash flow. To the extent that funding is required, there may be exchange controls limiting such funding or adverse tax consequences associated with such funding. In addition, taxes and exchange controls may affect the dividends that we receive from foreign subsidiaries.

The governments in Brazil and Argentina require us to register funds that enter and exit the country with the central bank in each country. In Brazil, Argentina and Colombia, all transactions must be carried out in the local currency of the country. Exchange controls may prevent us from transferring funds abroad. For example, the Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentina subsidiaries to make dividend or loan payments to us and there may be a tax imposed with respect to the expatriation of such proceeds.

In Colombia, we participate in a special exchange regime, which allows us to receive revenue in U. S. dollars offshore. This regime gives us flexibility to determine the currency in which we receive our revenues, rather than to be restricted to Colombian pesos if received in Colombia, but also limits the ways in which we are able to fund our operations in Colombia. As such, this could cause us to employ funding strategies for our Colombian operations that are not as tax efficient as might otherwise be if we did not participate in the special exchange regime.

Tax law changes can impact the way we provide cross-border funding to our operating subsidiaries, as well as impact the after tax profits available for expatriation. For example, beginning in 2013, the Colombian rate of tax applicable to ordinary income derived by our Colombian operations has changed for the 3-year period 2013-2015 from 33% to 34%. Also in Colombia, beginning in 2013, a new definition of dividends is applied for branches. In this case, the transfer of branch profits are considered as dividends subject to a 25% tax if those dividends have not already been subject to Colombian tax. We do not currently expect that this change in Colombian law will have a material consequence.

Maintaining Good Community Relationships and Being a Good Corporate Citizen may be Costly and Difficult to Manage.

Our operations have a significant effect on the areas in which we operate. To enjoy the confidence of local populations and the local governments, we must invest in the communities where we operate. In many cases, these communities are impoverished and lack many resources taken for granted in North America. The opportunities for investment are large, many and varied; however, we must be careful to invest carefully in projects that will truly benefit these areas. Improper management of these investments and relationships could lead to a delay in operations, loss of license or major impact to our reputation in these communities, which could adversely affect our business.

Our Operations Involve Substantial Costs and are Subject to Certain Risks Because the Oil and Gas Industries in the Countries in Which We Operate are Less Developed.

The oil and gas industry in South America is not as efficient or developed as the oil and gas industry in North America. As a result, our exploration and development activities may take longer to complete and may be more expensive than similar operations in North America. The availability of technical expertise, specific equipment and supplies may be more limited than in North America. We expect that such factors will subject our international operations to economic and operating risks that may not be experienced in North American operations.

Further, we operate in remote areas and may rely on helicopter, boats or other transport methods. Some of these transport methods may result in increased levels of risk and could lead to operational delays, serious injury or loss of life and could have a significant impact on our reputation.

Negative Political Developments in Peru May Negatively Affect our Proposed Operations.

Peru held a national election in June 2011 after which a new political regime was elected, led by the left-populist candidate, Ollante Humala, who was elected the President. Mr. Humala has noted that the past decade prioritized the strengthening of democracy with economic growth, while the new government will enhance social inclusion to benefit the neediest. This political regime may adopt new policies, laws and regulations that are more hostile toward foreign investment which may result in the imposition of additional taxes, the adoption of regulations that limit price increases, termination of contract rights, or the expropriation of foreign-owned assets. While we do not have any reserves or any producing wells in Peru at this time, we do hold significant land holdings in Peru and such actions by the elected political regime could limit the amount of our future revenue in that country and affect our results of operations.

The United States Government May Impose Economic or Trade Sanctions on Colombia That Could Result In A Significant Loss To Us.

Colombia is among several nations whose eligibility to receive foreign aid from the United States is dependent on its progress in stemming the production and transit of illegal drugs, which is subject to an annual review by the President of the United States. Although Colombia is currently eligible for such aid, Colombia may not remain eligible in the future. A finding by the President that Colombia has failed demonstrably to meet its obligations under international counternarcotics agreements 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 Corporation 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 our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with ANH and Ecopetrol and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets.

Accordingly, the imposition of the foregoing economic and trade sanctions on Colombia would likely result in a substantial loss and a decrease in the price of shares of our Common Stock. The United States may impose sanctions on Colombia in the future, and we cannot predict the effect in Colombia that these sanctions might cause.

We May Be Unable to Obtain Additional Capital That We Will Require to Implement Our Business Plan, Which Could Restrict Our Ability to Grow.

We expect that our existing cash resources and the availability to draw cash under our credit agreement will be sufficient to fund our currently planned activities. We may require additional capital to expand our exploration and development programs to additional properties. We may be unable to obtain additional capital required.

When we require additional capital, we plan to pursue sources of capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. We may not be successful in locating suitable financing transactions in the time period required or at all, and we may not obtain the capital we require by other means. If we do succeed in raising additional capital, future financings may be dilutive to our shareholders, as we could issue additional shares of Common Stock or other equity to investors. In addition, debt and other mezzanine financing may involve a pledge of assets and may be senior to interests of equity holders. We may incur substantial costs in pursuing future capital financing, including investment banking fees, legal fees, accounting fees, securities law compliance fees, printing and distribution expenses and other costs. We may also be required to recognize non-cash expenses in connection with certain securities we may issue, such as convertibles and warrants, which will adversely impact our financial results.

Our ability to obtain needed financing may be impaired by factors such as the capital markets (both generally and in the oil and gas industry in particular), the location of our oil and natural gas properties in South America, prices of oil and natural gas on the commodities markets (which will impact the amount of asset-based financing available to us), and the loss of key management. Further, if oil and/or natural gas prices on the commodities markets decrease, then our revenues will likely decrease, and such decreased revenues may increase our requirements for capital. Some of the contractual arrangements governing our exploration activity may require us to commit to certain capital expenditures, and we may lose our contract rights if we do not have the required capital to fulfill these commitments. If the amount of capital we are able to raise from financing activities, together with our cash flow from operations, is not sufficient to satisfy our capital needs (even to the extent that we reduce our activities), we may be required to curtail our operations.

We May Not Be Able To Effectively Manage Our Growth, Which May Harm Our Profitability.

Our strategy envisions continually expanding our business, both organically and through acquisition of other properties and companies. If we fail to effectively manage our growth or integrate successfully our acquisitions, our financial results could be adversely affected. Growth may place a strain on our management systems and resources. Integration efforts place a significant burden on our management and internal resources. The diversion of management attention and any difficulties encountered in the integration process could harm our business, financial condition and results of operations. In addition, we must continue to refine and expand our business development capabilities, our systems and processes and our access to financing sources. As we grow, we must continue to hire, train, supervise and manage new or acquired employees. We may not be able to:

- expand our systems effectively or efficiently or in a timely manner;
- allocate our human resources optimally;
- identify and hire qualified employees or retain valued employees; or
- incorporate effectively the components of any business that we may acquire in our effort to achieve growth.

If we are unable to manage our growth and our operations our financial results could be adversely affected by inefficiencies, which could diminish our profitability.

Guerrilla Activity in Peru Could Disrupt or Delay Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Peru.

The Shining Path Guerilla group has been active in Peru since the early 1980's and, at one point, was active throughout the country. Recently, the group's activity has been confined to small areas of Peru and operations have been hampered by the capture of many high profile leaders and membership has fallen dramatically. During April 2012, 30 people working on the Camisea natural gas project in central Peru were kidnapped. Most of the workers were released after a short period of time, and the remainder were freed within a few days. The kidnapping was attributed to the Shining Path Guerilla group. Camisea is a very large, high profile project in an area where the group continues to be active. Our operations in Peru are in a different region, with no known activity by the group. Other groups may be active in other areas of the country and possibly our operational areas. We are monitoring the situation and increasing security measures as required. Nevertheless, we are concerned about the security of our operations in Peru and mitigate our risks through good relationships with local communities and stakeholders as well as strong security procedures.

Risks Related to Our Industry

Unless We are Able to Replace Our Reserves, and Develop and Manage Oil and Gas Reserves and Production on an Economically Viable Basis, Our Reserves, Production and Cash Flows May Decline as a Result.

Our future success depends on our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We may not be able to find, develop or acquire additional reserves at acceptable costs.

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues 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-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and technical conditions. While we will endeavor to effectively manage these conditions, we may not be able to do so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

We are Required to Obtain Licenses and Permits to Conduct Our Business and Failure to Obtain These Licenses Could Cause Significant Delays and Expenses That Could Materially Impact Our Business.

We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. For example, the permitting process in Peru takes significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere. Other drilling projects are being delayed because the Ministry of the Environment has not increased staffing levels to meet increased activity in the oil and gas industry in Colombia and so permit processing takes longer than usual. These delays are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations. For example, currently in Brazil, we are subject to restrictions on flaring natural gas, which have the impact of limiting our production capacity.

Our Exploration for Oil and Natural Gas Is Risky and May Not Be Commercially Successful, Impairing Our Ability to Generate Revenues from Our Operations.

Oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our exploration expenditures may not result in new discoveries of oil or natural gas in commercially viable quantities. It is difficult to project the costs of implementing an 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. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations.

Estimates of Oil and Natural Gas Reserves that We Make May Be Inaccurate and Our Actual Revenues May Be Lower and Our Operating Expenses may be Higher than Our Financial Projections.

We make estimates of oil and natural gas reserves, upon which we will base our financial projections. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Economic factors beyond our control, such as interest rates and exchange rates, will also impact the value of our reserves. The process of estimating oil and gas reserves is complex, and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

Exploration, development, production (including transportation and workover costs), marketing (including distribution costs) and regulatory compliance costs (including taxes) will substantially impact the net revenues we derive from the oil and gas that we produce. These costs are subject to fluctuations and variation in different locales in which we operate, and we may not be able to predict or control these costs. If these costs exceed our expectations, this may adversely affect our results of operations. In addition, we may not be able to earn net revenue at our predicted levels, which may impact our ability to satisfy our obligations.

If Oil and Natural Gas Prices Decrease, We May be Required to Take Write-Downs of the Carrying Value of Our Oil and Natural Gas Properties.

We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. The net book value is compared with the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense. Under full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings. In countries where we do not have proved reserves, dry wells drilled in a period would directly result in ceiling test impairment for that period.

In 2011, we recorded a ceiling test impairment loss of \$42.0 million in our Peru cost center related to seismic and drilling costs on two blocks which were relinquished and a ceiling test impairment loss of \$25.7 million in our Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. In 2012, we recorded a ceiling test impairment loss of \$20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. The farm-out agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period.

Our Inability to Obtain Necessary Facilities and/or Equipment Could Hamper Our Operations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment, transportation, power and technical support in the particular areas where these activities will be conducted, and our access to these facilities may be limited. To the extent that we conduct our activities in remote areas, needed facilities or equipment may not be proximate to our operations, which will increase our expenses. Demand for such limited equipment and other facilities or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. The quality and reliability of necessary facilities or equipment may also be unpredictable and we may be required to make efforts to standardize our facilities, which may entail unanticipated costs and delays. Shortages and/or the unavailability of necessary equipment or other facilities will impair our activities, either by delaying our activities, increasing our costs or otherwise.

Drilling New Wells and Producing Oil and Natural Gas from Existing Facilities Could Result in New Liabilities, Which Could Endanger Our Interests in Our Properties and Assets.

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires and spills. Earthquakes or weather related phenomena such as heavy rain, landslides, storms and hurricanes can also cause problems in drilling new wells. There are also risks in producing oil and natural gas from existing facilities. For example, the Valle Morado GTE.St.VMor-2001 re-entry operations started in the third quarter of 2010, with integrity testing and remediation operations required for the sidetrack operations. Due to operational difficulties, the initial side-track attempt was not successful. The operation was placed on standby pending the arrival of additional side-track equipment and operations recommenced in the fourth quarter of 2010. In February 2011, these operations were suspended and the wellbore has been abandoned due to a number of operational challenges encountered. We continue to review alternatives associated with the field development. Also for example, on February 7, 2009, we experienced an incident at our Juanambu-1 well, involving a fire in a generator, resulting in total damage to equipment estimated at \$500,000, and production in the amount of approximately \$125,000 being deferred due to shutting down production facilities while dealing with the incident. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. Incidents such as these can lead to serious injury, property damage and even loss of life. We generally obtain insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Prices and Markets for Oil and Natural Gas Are Unpredictable and Tend to Fluctuate Significantly, Which Could Reduce Our Profitability, Growth and Value.

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for WTI per barrel was \$66 in 2006, \$72 in 2007, \$100 in 2008, \$62 in 2009, \$79 in 2010, \$95 in 2011 and \$94 in 2012, demonstrating the inherent volatility in the market. Average Brent oil prices for the year ended December 31, 2012, were \$111.67 per bbl. Given the current economic environment and unstable conditions in the Middle East, North Africa, the United States and Europe, the oil price environment is increasingly unpredictable and unstable. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations and quantities of reserves recoverable on an economic basis.

In addition, oil and natural gas prices in Argentina are effectively regulated and during 2009, 2010, 2011 and 2012, were substantially lower than those received in North America. Oil prices in Colombia are related to international market prices, but adjustments that are defined by contract with Ecopetrol, the purchaser of most of the oil that we produce in Colombia, may cause realized prices to be lower or higher than those received in North America. Oil prices in Brazil are defined by contract with the refinery and may be lower or higher than those received in North America.

Decommissioning Costs Are Unknown and May be Substantial; Unplanned Costs Could Divert Resources from Other Projects.

We are responsible for costs associated with abandoning and reclaiming some of the wells, facilities and pipelines which we use for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We have determined that we require a reserve account for these potential costs in respect of our current properties and facilities at this time, and have booked such reserve on our financial statements. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Penalties We May Incur Could Impair Our Business.

Our exploration, development, production and marketing operations are regulated extensively under foreign, federal, state and local laws and regulations. Under these laws and regulations, we could be held liable for personal injuries, property damage, site clean-up and restoration obligations or costs and other damages and liabilities. We may also be required to take corrective actions, such as installing additional safety or environmental equipment, which could require us to make significant capital expenditures. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages. We could be required to indemnify our employees in connection with any expenses or liabilities that they may incur individually in connection with regulatory action against them. As a result of these laws and regulations, our future business prospects could deteriorate and our profitability could be impaired by costs of compliance, remedy or indemnification of our employees, reducing our profitability.

Policies, Procedures and Systems to Safeguard Employee Health, Safety and Security May Not be Adequate.

Oil and natural gas exploration and production is dangerous. Detailed and specialized policies, procedures and systems are required to safeguard employee health, safety and security. We have undertaken to implement best practices for employee health, safety and security; however, if these policies, procedures and systems are not adequate, or employees do not receive adequate training, the consequences can be severe including serious injury or loss of life, which could impair our operations and cause us to incur significant legal liability.

Environmental Risks May Adversely Affect Our Business.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require us to incur costs to remedy such discharge. The application of environmental laws to our business may cause us to curtail our production or increase the costs of our production, development or exploration activities.

Our Insurance May Be Inadequate to Cover Liabilities We May Incur.

Our involvement in the exploration for and development of oil and natural gas properties may result in our becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although we have insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, we may choose not to obtain insurance to protect against specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to us. If we suffer a significant event or occurrence that is not fully insured, or if the insurer of such event is not solvent, we could be required to divert funds from capital investment or other uses towards covering our liability for such events.

Challenges to Our Properties May Impact Our Financial Condition.

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. While we intend to make appropriate inquiries into the title of properties and other development rights we acquire, title defects may exist. In addition, we may be unable to obtain adequate insurance for title defects, on a commercially reasonable basis or at all. If title defects do exist, it is possible that we may lose all or a portion of our right, title and interest in and to the properties to which the title defects relate.

Furthermore, applicable governments may revoke or unfavorably alter the conditions of exploration and development authorizations that we procure, or third parties may challenge any exploration and development authorizations we procure. Such rights or additional rights we apply for may not be granted or renewed on terms satisfactory to us.

If our property rights are reduced, whether by governmental action or third party challenges, our ability to conduct our exploration, development and production may be impaired.

We Will Rely on Technology to Conduct Our Business and Our Technology Could Become Ineffective Or Obsolete.

We rely on technology, including geographic and seismic analysis techniques and economic models, to develop our reserve estimates and to guide our exploration and development and production activities. We will be required to continually enhance and update our technology to maintain its efficacy and to avoid obsolescence. The costs of doing so may be substantial, and may be higher than the costs that we anticipate for technology maintenance and development. If we are unable to maintain the efficacy of our technology, our ability to manage our business and to compete may be impaired. Further, even if we are able to maintain technical effectiveness, our technology may not be the most efficient means of reaching our objectives, in which case we may incur higher operating costs than we would were our technology more efficient.

Risks Related to Our Common Stock

The Market Price of Our Common Stock May Be Highly Volatile and Subject to Wide Fluctuations.

The market price of shares of our Common Stock may be highly volatile and could be subject to wide fluctuations in response to a number of factors that are beyond our control, including but not limited to:

- dilution caused by our issuance of additional shares of Common Stock and other forms of equity securities, which we expect to make in connection with acquisitions of other companies or assets;
- announcements of new acquisitions, reserve discoveries or other business initiatives by our competitors;
- fluctuations in revenue from our oil and natural gas business;
- changes in the market and/or WTI or Brent price for oil and natural gas commodities and/or in the capital markets generally, or under our credit agreement;
- changes in the demand for oil and natural gas, including changes resulting from the introduction or expansion of alternative fuels;
- changes in the social, political and/or legal climate in the regions in which we will operate;
- changes in the valuation of similarly situated companies, both in our industry and in other industries;
- changes in analysts' estimates affecting us, our competitors and/or our industry;
- changes in the accounting methods used in or otherwise affecting our industry;
- announcements of technological innovations or new products available to the oil and natural gas industry;
- announcements by relevant governments pertaining to incentives for alternative energy development programs;
- fluctuations in interest rates, exchange rates and the availability of capital in the capital markets; and
- significant sales of shares of our Common Stock, including sales by future investors in future offerings we expect to make to raise additional capital.

In addition, the market price of shares of our Common Stock could be subject to wide fluctuations in response to various factors, which could include the following, among others:

- quarterly variations in our revenues and operating expenses; and
- additions and departures of key personnel.

These and other factors are largely beyond our control, and the impact of these risks, singularly or in the aggregate, may result in material adverse changes to the market price of shares of our Common Stock and/or our results of operations and financial condition.

We Do Not Expect to Pay Dividends In the Foreseeable Future.

We do not intend to declare dividends for the foreseeable future, as we anticipate that we will reinvest any future earnings in the development and growth of our business. Therefore, investors will not receive any funds unless they sell their shares of Common Stock, and shareholders may be unable to sell their shares on favorable terms or at all. Investors cannot be assured of a positive return on investment or that they will not lose the entire amount of their investment in shares of our Common Stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We have described our properties, reserves, acreage, wells, production and drilling activity in Part I, Item 1. "Business" of this Annual Report on Form 10-K, which information and descriptions are incorporated by reference here.

Administrative Facilities

Our executive offices are located in Calgary Canada. Our primary executive offices comprise approximately 15,700 square feet, which we lease for approximately \$33,000 per month under a lease that expires on October 30, 2015. We also lease additional space in Calgary that we use to supplement our primary executive office space. We lease administrative office space in Colombia, Argentina, Peru and Brazil. We believe that our current executive and administrative offices are sufficient for our purposes or, to the extent that we need additional office space, that additional office space will be readily available to us.

Item 3. Legal Proceedings

Gran Tierra's production from the Costayaco field is subject to an additional royalty that applies when cumulative gross production from a commercial field is greater than five MMbbl. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra's view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process and filed an arbitration claim. As at December 31, 2012, total cumulative production from the Moqueta field was 0.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is \$15.1 million. At this time, no amount has been accrued in the financial statements nor deducted from our reserves for the disputed royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra Energy Colombia, Ltd are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the additional royalty. Discussions with the ANH are ongoing. As at December 31, 2012, the estimated compensation which would be payable if the ANH's interpretation is successful is \$11.6 million. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

We have several other lawsuits and claims pending. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we believe the resolution of these matters would not have a material adverse effect on our consolidated financial position, results of operations or cash flows. We record costs as they are incurred or become probable and determinable.

Item 4. Mine Safety Disclosures

Not applicable.

End of Item 4

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 20, 2013.

Name	Age	Position
Dana Coffield	54	President and Chief Executive Officer; Director
James Rozon	49	Chief Financial Officer
Shane O'Leary	56	Chief Operating Officer
David Hardy	58	General Counsel, Vice-President Legal, and Secretary
Rafael Orunesu	57	President and General Manager Gran Tierra Energy Argentina
Duncan Nightingale	54	President and General Manager Gran Tierra Energy Colombia
Julio Cesar Moreira	51	President and General Manager Gran Tierra Energy Brazil
Carlos Monges	56	President and General Manager Gran Tierra Energy Peru

Dana Coffield, President, Chief Executive Officer and Director. Before joining Gran Tierra as President, Chief Executive Officer and a Director in May, 2005, Mr. Coffield led the Middle East Business Unit for Encana Corporation, at the time North America's largest independent oil and gas company, from 2003 to 2005. His responsibilities included business development, exploration operations, commercial evaluations, government and partner relations, planning and budgeting, environment/health/safety, security and management of several overseas operating offices. From 1998 through 2003, he was New Ventures Manager for Encana's predecessor — Alberta Energy Company — where he expanded exploration operations into five new countries on three continents. Mr. Coffield was previously with ARCO International for ten years, where he participated in exploration and production operations in North Africa, Southeast Asia and Alaska. He began his career as a mud-logger in the Texas Gulf Coast and later as a Research Assistant with the Earth Sciences and Resources Institute where he conducted geoscience research in North Africa, the Middle East and Latin America. Mr. Coffield graduated from the University of South Carolina with a Masters of Science (MSc) degree and a doctorate (PhD) in Geology, based on research conducted in the Oman Mountains in Arabia and Gulf of Suez in Egypt, respectively. He has a Bachelor of Science degree in Geological Engineering from the Colorado School of Mines. Mr. Coffield is a member of the AAPG and the CSPG, and is a Fellow of the Explorers Club.

James Rozon, Chief Financial Officer. On May 2, 2012, James Rozon was promoted from acting Chief Financial Officer to Chief Financial Officer. Mr. Rozon had been serving as acting Chief Financial Officer since December 9, 2011. Mr. Rozon served as Gran Tierra's Corporate Controller from October 1, 2007 to December 9, 2011. He has previous experience in accounting, finance and administration in the petroleum and technology industries in Canada. During his career, his responsibilities have included management of finance related activities of Canadian and American oil and gas exploration and production companies operating in Canada and the United States and a software development company operating in Canada, the United States, China and Sweden. He was Controller of Sound Energy Trust, a publicly listed Canadian oil and gas trust from July 2006 to September 2007, at which time it was sold. From October 2002 to June 2006, and previously from July 1995 to February 1998, he was the Corporate Controller of Zi Corporation, a Canadian software development company publicly listed in both Canada and the United States of America. From June 2000 to September 2002, he was the Controller for Energy Exploration Technologies, an American publicly listed oil and gas exploration company operating in Canada and the United States. From April 1998 to May 2000, he was the Manager, Financial Reporting of Summit Resources Limited, a publicly listed Canadian oil and gas exploration and development company with operations in Canada and the United States of America. From June 1990 to June 1995, Mr. Rozon worked in public practice for five years for Deloitte & Touche LLP including one year as an audit manager in the Oil and Gas group in the Calgary, Alberta office. Mr. Rozon holds a Bachelor of Commerce degree from the University of Saskatchewan and is a member of the Institute of Chartered Accountants of Alberta and the Institute of Chartered Accountants of Saskatchewan.

Shane P. O'Leary, Chief Operating Officer. Mr. O'Leary joined the company as Chief Operating Officer effective March 2, 2009. Mr. O'Leary's regional experience includes South America, North Africa, the Middle East, the former Soviet Union, and North America. Prior to joining Gran Tierra, Mr. O'Leary was President and Chief Executive Officer of First Calgary Petroleums Ltd., an oil and natural gas company actively engaged in exploration and development activities in Algeria. In this role, he was responsible for all operating and corporate activities involved in a \$2 billion development program for the exploitation of a resource base exceeding three trillion cubic feet of natural gas equivalent in the Sahara desert, Algeria. Mr. O'Leary led initiatives to explore strategic options which resulted in the sale of the company to ENI SpA for over \$1 billion. From 2002 to 2006, Mr. O'Leary worked for Encana Corporation where his positions included Vice President of Development Planning and Engineering, International New Ventures, as well as Vice President Brazil Business Unit. In these roles Mr. O'Leary was responsible for all engineering and development planning for new discoveries of the International New Ventures Division and later leading the Brazil team involved in appraising an offshore discovery subsequently divested for \$360 million.

Mr. O'Leary was also architect of a technology cooperation agreement with Petrobras involving numerous partnerships in offshore acreage in exchange for assistance to Petrobras in applying Canadian Heavy Oil production technology in Brazil. From 1985 to 2002 he worked for the Amoco Production Company/BP Exploration where he occupied numerous senior finance, planning, and business development positions with assignments in Canada, U.S.A., Azerbaijan and Egypt, culminating in his role as Business Development Manager for BP Alaska Gas. Early in his career Mr. O'Leary worked as a Corporate Banking Officer for Bank of Montreal's Petroleum group in Calgary, a Reservoir Engineer for Dome Petroleum, and as a Senior Field Engineer for Schlumberger Overseas, S.A. in Kuwait. Mr. O'Leary earned his Bachelor of Science degree in chemical engineering from Queen's University in Kingston, Ontario and his Masters in Business Administration from the University of Western Ontario in London, Ontario. He is a member of the Canadian National Committee of the World Petroleum Council and The Association of Professional Engineers, Geologists, and Geophysicists of Alberta (P. Eng).

David Hardy, General Counsel, Vice President Legal and Secretary. Mr. Hardy joined Gran Tierra as General Counsel, Vice President Legal and Secretary on March 1, 2010. He has more than 20 years' experience in the legal profession. Before joining Gran Tierra, he worked for Encana Corporation from 2000 through 2009 where he held various positions, including: Vice President Divisional Legal Services, Integrated Oil and Canadian Plains Divisions; Vice President Regulatory Services, Corporate Relations Division; and Associate General Counsel, Offshore and International Division. For four of his eight years in the Offshore and International Division of Encana, Mr. Hardy led the Legal and Commercial Negotiations Group, where he was responsible for providing strategic legal, commercial and negotiation advice and support to the offshore and international business units. This included dealing with new venture activities and operational, joint venture and host government issues relating to projects in various countries, including Australia, Brazil, Chad, Libya, Oman, Qatar and Yemen. Prior to joining Encana, Mr. Hardy spent over 10 years in private practice and was a partner in a law firm in Calgary, Alberta. He holds a Juris Doctor Degree from the University of Calgary (converted from an LL.B Degree in 2011) and is a member of the Law Society of Alberta and the Association of International Petroleum Negotiators.

Rafael Orunesu, President and General Manager Gran Tierra Argentina. Mr. Orunesu joined Gran Tierra in March 2005. He brings a mix of operations management, project evaluation, production geology, reservoir and production engineering skills to Gran Tierra, with a South American focus. Prior to joining Gran Tierra he was Engineering Manager for Pluspetrol Peru, from 1997 through 2004, responsible for planning and development operations in the Peruvian North jungle. He participated in numerous evaluation and asset purchase and sale transactions covering Latin America and North Africa, discovering 200 MMBbl of oil over a five-year period. Mr. Orunesu was previously with Pluspetrol Argentina from 1990 to 1996 where he managed the technical/economic evaluation of several oil fields. He began his career with YPF, initially as a geologist in the Austral Basin of Argentina and eventually as Chief of Exploitation Geology and Engineering for the Catriel Field in the Neuquén Basin, where he was responsible for drilling programs, workovers and secondary recovery projects.

Mr. Orunesu has a postgraduate degree in Reservoir Engineering and Exploitation Geology from Universidad Nacional de Buenos Aires and a degree in Geology from Universidad Nacional de la Plata, Argentina.

Duncan Nightingale, President and General Manager Gran Tierra Energy Colombia. Mr. Nightingale joined Gran Tierra in September 2009, where he served in our Calgary, Canada office as our Vice President of Exploration from September 2009 to January 2011. He served in our Bogotá, Colombia office as our Senior Manager Project Planning and Exploration from January 2011 until August 2011, and was promoted to President of Gran Tierra Energy Colombia in August 2011. Prior to joining Gran Tierra, Mr. Nightingale was Senior Vice President, Exploration & Production, at Artumas Group Inc., a Canadian oil and gas company focusing on exploration and development of hydrocarbon reserves in Tanzania and Mozambique, where he was responsible for Artumas Group's exploration and production operations in Mozambique and Tanzania and management of its gas processing plant and power generation facility in Tanzania. Prior to Artumas Group, Mr. Nightingale was General Manager, Exploration & Production, with Dana Gas PJSC, a leading private sector natural gas company in the Middle East, where Mr. Nightingale was responsible for all of Dana Gas's exploration and production operations, and was responsible for a multi-million dollar exploration and development program in Kurdistan. Prior to Dana Gas, Mr. Nightingale was with Encana Corporation's International Division from May 2002 until March 2007. From June 2002 until September 2003, he was the Country Manager in Qatar, responsible for managing Encana's activities in Qatar, including the execution of exploration programs and new venture activity. From October 2003 until June 2006, he had similar responsibilities in the Sultanate of Oman, where he served as Encana's Country Manager. Mr. Nightingale has a total of 30 years of corporate head office and resident in-country international operating experience, spanning all aspects of managing exploration programs, development and production operations, new business ventures, portfolio management and strategic planning. Mr. Nightingale graduated from the University of Nottingham in the U.K. with a Bachelor of Science degree with honors in Geology.

Julio Cesar Moreira, President and General Manager Gran Tierra Energy Brasil. Mr. Moreira joined our company as President, Gran Tierra Brazil in September 2009. Mr. Moreira has over 25 years of experience working for international companies in Brazil and USA in senior business development and management positions. Most recently, he was Managing Director for IBV Brasil Petroleo Ltda from September 2008 to August 2009 where he managed a portfolio of assets including 10 Exploration Deep Water Blocks located in Sergipe-Alagoas, Espirito Santo, Potiguar and Campos Basins, all in Brazil, and Brazil Country Manager for Encana Corporation from December 2001 to September 2008, where he was instrumental in capturing assets which were later sold for a combined value of over \$500 million. Before Encana Corporation, Mr. Moreira was Brazil New Ventures & Business Development Vice President for Unocal Corporation where he successfully completed a \$180 million corporate transaction to acquire a Natural Gas / Condensate field in Northeast Brazil and captured Deep Water Exploration assets offshore Brazil. Mr. Moreira holds an Information Technology degree from Universidade Federal Fluminense in Rio de Janeiro, and a post-graduate degree in Marketing from Rio Catholic University. In addition, he attended the Executive MBA Program at UFRJ/Coppead (Brazil), the Executive Management programs in Oil and Gas at Thunderbird (USA) and the Ivey Executive Program at the University of Western Ontario (Canada).

Carlos Monges, President and General Manager Gran Tierra Energy Peru. Mr. Monges has over 30 years of experience in the oil industry. He joined our company upon its acquisition of Petrolifera Petroleum Limited ("Petrolifera") in March 2011. He was Petrolifera's country manager in Peru since 2005, with responsibility for management and exploratory operations in three onshore blocks. He was the senior geologist on the team that performed for PeruPetro S.A. ("PeruPetro") a geological and geophysical assessment of Peru's hydrocarbon basins which was sponsored by the Canadian and Peruvian governments. Prior to that, Mr. Monges was the Operations Manager for Energy Development, Anadarko Petroleum and then BPZ Energy with respect to various offshore and onshore blocks in Peru. He began his career in the industry working as a field development geologist and a well-site and production geologist in Talara Basin for Petróleos del Perú S.A. and Occidental Petroleum and also worked as a mud engineer in drilling operations in Venezuela and Argentina. Mr. Monges received his Bachelor of Science Degree in Geological Engineering from Universidad Nacional Mayor de San Marcos, Lima in 1978, performed studies on exploration techniques at Robertson Research Center in United Kingdom in 1990, and completed certificate studies on oil industry management at the IHRDC program in Boston, USA in 1997. He is a current member and past director of the Peruvian Geological Society.

PART II

Item 5. Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Shares of our Common Stock trade on the NYSE MKT, and on the Toronto Stock Exchange ("TSX") under the symbol "GTE". In addition, the exchangeable shares in one of our subsidiaries, Gran Tierra Exchangeco, are listed on the TSX and are trading under the symbol "GTX".

As of February 20, 2013, there were approximately: 38 holders of record of shares of our Common Stock and 268,621,445 shares outstanding with \$0.001 par value; and one share of Special A Voting Stock, \$0.001 par value representing approximately six holders of record of 6,223,810 exchangeable shares which may be exchanged on a 1-for-1 basis into shares of our Common Stock; and one share of Special B Voting Stock, \$0.001 par value, representing nine holders of record of 7,058,678 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into shares of our Common Stock.

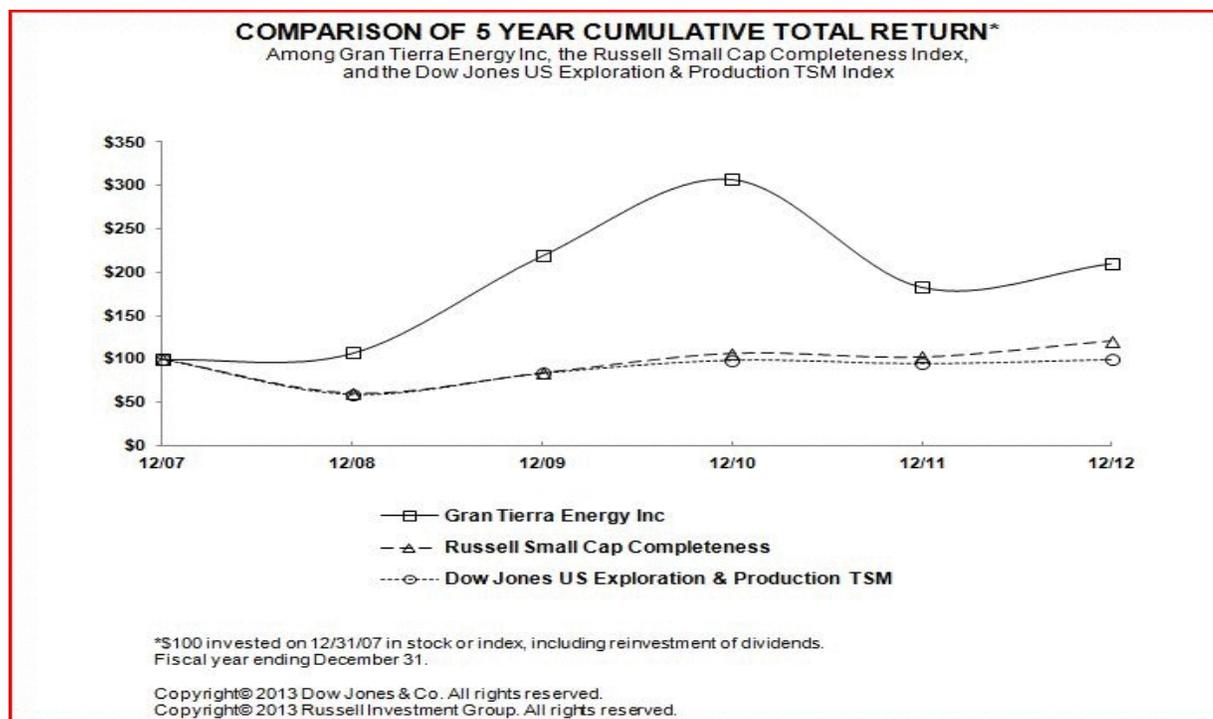
For the quarters indicated from January 1, 2011, through the end of the fourth quarter of 2012, the following table shows the high and low closing sale prices per share of our Common Stock as reported on the NYSE MKT.

	High	Low
Fourth Quarter 2012	\$ 5.93	\$ 4.87
Third Quarter 2012	\$ 5.51	\$ 4.17
Second Quarter 2012	\$ 6.64	\$ 4.44
First Quarter 2012	\$ 6.29	\$ 4.73
Fourth Quarter 2011	\$ 6.47	\$ 4.42
Third Quarter 2011	\$ 7.20	\$ 4.68
Second Quarter 2011	\$ 8.17	\$ 6.10
First Quarter 2011	\$ 9.54	\$ 7.75

Dividend Policy

We have never declared or paid dividends on the shares of Common Stock and we intend to retain future earnings, if any, to support the development of the business and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including current financial condition, operating results and current and anticipated cash needs. Under the terms of our credit facility we cannot pay any dividends to our shareholders if we are in default under the facility, and if we are not in default then are required to obtain bank approval for any dividend payments made by us exceeding \$2 million in any fiscal year.

Performance Graph



Copyright© 2013 Dow Jones & Company. All rights reserved.

Copyright© 2013 Russell Investment Group. All rights reserved.

	12/07	12/08	12/09	12/10	12/11	12/12
Gran Tierra Energy Inc	100.00	106.87	218.70	307.25	183.21	210.31
Russell Small Cap Completeness	100.00	61.02	84.03	106.40	102.23	120.68
Dow Jones US Exploration & Production TSM	100.00	58.97	83.46	98.81	94.76	99.66

Item 6. Selected Financial Data

(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

Statement of Operations Data

	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Oil and natural gas sales	\$ 583,109	\$ 596,191	\$ 373,286	\$ 262,629	\$ 112,805
Interest income	2,078	1,216	1,174	1,087	1,224
	585,187	597,407	374,460	263,716	114,029
Operating expenses	124,903	86,497	59,446	40,784	19,218
DD&A expenses	182,037	231,235	163,573	135,863	25,737
G&A expenses	58,882	60,389	40,241	28,787	18,593
Other gain	(9,336)	—	—	—	—
Equity tax	—	8,271	—	—	—
Financial instruments gain (loss)	—	(1,522)	(44)	190	(193)
Gain on acquisition	—	(21,699)	—	—	—
Foreign exchange loss (gain)	31,338	(11)	16,838	19,797	6,235
	387,824	363,160	280,054	225,421	69,590
Income before income taxes	197,363	234,247	94,406	38,295	44,439
Income tax expense	(97,704)	(107,330)	(57,234)	(24,354)	(20,944)
Net income	\$ 99,659	\$ 126,917	\$ 37,172	\$ 13,941	\$ 23,495
Net income per common share - basic	\$ 0.35	\$ 0.46	\$ 0.15	\$ 0.06	\$ 0.19
Net income per common share - diluted	\$ 0.35	\$ 0.45	\$ 0.14	\$ 0.05	\$ 0.16

Balance Sheet Data

	As at December 31, 2012	As at December 31, 2011	As at December 31, 2010	As at December 31, 2009	As at December 31, 2008
Cash and cash equivalents	\$ 212,624	\$ 351,685	\$ 355,428	\$ 270,786	\$ 176,754
Working capital (including cash)	222,468	213,100	265,835	215,161	132,807
Oil and gas properties	1,196,661	1,036,850	721,157	709,568	765,050
Deferred tax asset - long term	1,401	4,747	—	7,218	10,131
Total assets	1,732,875	1,626,780	1,249,254	1,143,808	1,072,625
Deferred tax liability - long term	225,195	186,799	204,570	216,625	213,093
Total long-term liabilities	250,059	207,633	210,075	221,786	218,461
Shareholders' equity	\$ 1,291,431	\$ 1,174,318	\$ 886,866	\$ 816,426	\$ 791,926

In November 2008, we acquired Solana Resources Limited (“Solana”) for \$671.8 million through the issuance to Solana stockholders of either shares of our Common Stock or shares of common stock of a subsidiary of Gran Tierra. On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera Petroleum Limited (“Petrolifera”) pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia

and Peru. See “Business Combination” in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for further details.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

This report, and in particular this Management’s Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language at the very beginning of this Annual Report on Form 10-K regarding the identification of and risks relating to forward-looking statements, as well as Part I, Item 1A “Risk Factors” in this Annual Report on Form 10-K.

The following discussion of our financial condition and results of operations should be read in conjunction with the “Financial Statements and Supplementary Data” as set out in Part II, Item 8 of this Annual Report on Form 10-K.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America in Colombia, Argentina, Peru, and Brazil, and we are headquartered in Calgary, Alberta, Canada. For the year ended December 31, 2012, 84% (year ended December 31, 2011 - 91%; year ended December 31, 2010 - 96%) of our revenue and other income was generated in Colombia.

As of December 31, 2012, we had estimated proved reserves NAR of 40.6 MMBOE, comprising 95% oil and 5% natural gas, of which 72% were proved developed reserves. Our primary source of liquidity is cash generated from our operations.

The price of oil is a critical factor to our business and the price of oil has historically been volatile. Future volatility could be detrimental to our financial performance. During 2012, the average price realized for our oil was \$97.31 per barrel (2011 - \$96.60; 2010 - \$71.19).

Business Strategy

Our plan is to continue to build an international oil and gas company through acquisition and exploitation of under-developed prospective oil and gas assets, and to develop these assets with exploration and development drilling to grow commercial reserves and production. Our initial focus is in select countries in South America, currently Colombia, Argentina, Peru, and Brazil; we will consider other regions for future growth should those regions make strategic and commercial sense in creating additional value.

We have applied a two-stage approach to growth, initially establishing a base of production, development and exploration assets by selective acquisitions, and secondly achieving additional reserve and production growth through drilling. We intend to duplicate this business model in other areas as opportunities arise. We pursue opportunities in countries with proven petroleum systems; attractive royalty, taxation and other fiscal terms; and stable legal systems.

Highlights

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
Estimated Proved Oil and Gas Reserves, NAR, at December 31 (MMBOE)(1)	40.6	19	34.0	43	23.8
Production (BOEPD) (1)	16,897	(3)	17,408	20	14,448
Prices Realized - per BOE	\$ 94.29	—	\$ 93.83	33	\$ 70.79
Revenue and Other Income (\$000s)	\$ 585,187	(2)	\$ 597,407	60	\$ 374,460
Net Income (\$000s)	\$ 99,659	(21)	\$ 126,917	241	\$ 37,172
Net Income Per Share - Basic	\$ 0.35	(24)	\$ 0.46	207	\$ 0.15
Net Income Per Share - Diluted	\$ 0.35	(22)	\$ 0.45	221	\$ 0.14
Funds Flow From Operations (\$000s) (2)	\$ 323,756	1	\$ 319,046	57	\$ 203,136
Capital Expenditures (\$000s)	\$ 313,176	(4)	\$ 327,647	85	\$ 177,039

	As at December 31,				
	2012	% Change	2011	% Change	2010
Cash & Cash Equivalents (\$000s)	\$ 212,624	(40)	\$ 351,685	(1)	\$ 355,428
Working Capital (including cash & cash equivalents) (\$000s)	\$ 222,468	4	\$ 213,100	(20)	\$ 265,835
Property, Plant & Equipment (\$000s)	\$ 1,205,426	15	\$ 1,044,842	44	\$ 727,024

(1) Production represents production volumes NAR adjusted for inventory changes.

(2) Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under generally accepted accounting principles in the United States of America (“GAAP”). Management uses this financial measure to analyze operating performance and the income generated by our principal business activities prior to the consideration of how non-cash items affect that income, and believes that this financial measure is also useful supplemental information for investors to analyze operating performance and our financial results. Investors should be cautioned that this measure should not be construed as an alternative to net income or other measures of financial performance as determined in accordance with GAAP. Our method of calculating this measure may differ from other companies and, accordingly, it may not be comparable to similar measures used by other companies. Funds flow from operations, as presented, is net income adjusted for depletion, depreciation, accretion and impairment (“DD&A”) expenses, deferred taxes, stock-based compensation, unrealized gain on financial instruments, unrealized foreign exchange loss or gain, settlement of asset retirement obligation, other gains, equity tax and gain on acquisition. A reconciliation from net income to funds flow from operations is as follows:

Funds Flow From Operations - Non-GAAP Measure (\$000s)	Year Ended December 31,		
	2012	2011	2010
Net income	\$ 99,659	\$ 126,917	\$ 37,172
Adjustments to reconcile net income to funds flow from operations			
DD&A expenses	182,037	231,235	163,573
Deferred taxes	26,274	(28,685)	(19,679)
Stock-based compensation	12,006	12,767	8,025
Unrealized gain on financial instruments	—	(1,354)	(44)
Unrealized foreign exchange loss (gain)	17,054	(2,232)	14,375
Settlement of asset retirement obligation	(404)	(345)	(286)
Other gain	(9,336)	—	—
Equity tax	(3,534)	2,442	—
Gain on acquisition	—	(21,699)	—
Funds flow from operations	\$ 323,756	\$ 319,046	\$ 203,136

- For the year ended December 31, 2012, oil and gas production, NAR and adjusted for inventory changes, decreased by 3% to 16,897 BOEPD compared with 2011. Production, NAR and adjusted for inventory changes, in 2012 was 66% from the Chaza Block in Colombia and 12% and 6% from the Puesto Morales and Surubi Blocks in Argentina, respectively. Production during the year ended December 31, 2012, was impacted by an increase in oil inventory in the Ecopetrol-operated Trans-Andean oil pipeline (the "OTA pipeline") in Colombia and associated Ecopetrol owned facilities in the Putumayo Basin as a result of a change in the sales point from the entry into the OTA pipeline to the Port of Tumaco for volumes sold to Ecopetrol; oil delivery restrictions due to OTA pipeline disruptions; and increased oil inventory due to increased sales to a customer with a protracted sales cycle whereby the transfer of ownership occurs upon export, partially offset by production from new producing wells in Colombia and Argentina.
- Estimated proved oil and NGL reserves, NAR, as of December 31, 2012, were 38.5 MMbbl, a 25% increase from the estimated proved reserves as at December 31, 2011. The increase was due primarily to positive technical adjustments for the Costayaco field due to reservoir performance, successful appraisal drilling on the Moqueta field and exploration success with the Ramiriqui-1 well in Colombia. Reserves were also added through development drilling on the Tiê field in the Recôncavo Basin, Brazil and the Proa-2 development well on the Surubi Block in Argentina. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2012, were 14.8 MMbbl and 21.5MMbbl, respectively.
- Estimated proved gas reserves, NAR, as of December 31, 2012, were 12.8 Bcf compared with 18.3 Bcf as at December 31, 2011. At December 31, 2012, 61% of proved gas reserves were in the Sierra Nevada Block in Colombia and 26% were in the Puesto Morales Block in Argentina. Estimated proved gas reserves, NAR, in the Sierra Nevada Block decreased by 6.0 Bcf during the year ended December 31, 2012, due to technical revisions. Proved gas reserves in the Puesto Morales Block were consistent with the prior year end as new gas reserves were created to replace 2012 production. Estimated probable and possible gas reserves, NAR, as of December 31, 2012, were 5.1 Bcf and 51.7 Bcf, respectively, due to technical revisions in the Sierra Nevada Block.
- For the year ended December 31, 2012, revenue and other income decreased by 2% to \$585.2 million compared with \$597.4 million in 2011. The average price realized per BOE of \$94.29 was consistent with 2011 and was impacted by the settlement of a third party royalty dispute in Colombia which reduced the average realized price by \$1.76 per BOE.
- Net income decreased by 21% to \$99.7 million, or \$0.35 per share basic and diluted, for the year ended December 31, 2012, compared with \$126.9 million, or \$0.46 per share basic and \$0.45 per share diluted, in 2011. In 2012, decreased DD&A, G&A and income tax expenses, the realization of a value added tax recovery upon a corporate reorganization in Colombia and the absence of the Colombian equity tax expense were more than offset by decreased oil and natural gas sales, increased operating expenses and foreign exchange losses, and the absence of the 2011 gain on acquisition of Petrolifera Petroleum Limited ("Petrolifera").

- For the year ended December 31, 2012, funds flow from operations increased by 1% from \$319.0 million to \$323.8 million primarily due to lower income tax expenses being partially offset by increased operating expenses and realized foreign exchange losses.
- Cash and cash equivalents were \$212.6 million at December 31, 2012, compared with \$351.7 million at December 31, 2011. The change in cash and cash equivalents during 2012 was primarily the result of funds flow from operations of \$323.8 million, a \$11.9 million decrease in restricted cash and proceeds from issuance of common stock of \$4.3 million being more than offset by capital expenditures of \$276.1 million, an increase in net assets and liabilities from operating activities of \$167.4 million and cash paid for an acquisition in Brazil of \$35.5 million.
- Working capital (including cash and cash equivalents) was \$222.5 million at December 31, 2012, a \$9.4 million increase from December 31, 2011. The increase was primarily a result of the following: a \$50.5 million increase in accounts receivable due to a change in the timing of collection of Ecopetrol receivables, new customers in Colombia and increased oil and gas sales in Argentina; a \$26.4 million increase in inventory; an \$18.4 million increase in taxes receivable due to value added tax and income tax recoveries in Colombia generated upon completion of a corporate reorganization; a \$73.1 million decrease in taxes payable due to utilization of tax losses and tax deductions resulting from the same corporate reorganization, and lower taxable income in Colombia; partially offset by a \$139.1 million decrease in cash and cash equivalents and a \$19.7 million increase in accounts payable and accrued liabilities due to increased capital activity in Peru and Brazil immediately prior to year end.
- Property, plant and equipment at December 31, 2012, was \$1.2 billion, an increase of \$160.6 million from December 31, 2011, as a result of \$313.2 million of capital expenditures (including changes in non-cash working capital), the acquisition of the remaining 30% working interest in certain blocks in Brazil, partially offset by \$189.1 million of depletion, depreciation and impairment expenses.
- Our capital expenditures for the year ended December 31, 2012, were \$313.2 million compared with \$327.6 million for the year ended December 31, 2011. In 2012, capital expenditures included drilling of \$218.1 million, acquisitions of \$12.5 million, geological and geophysical ("G&G") expenditures of \$48.0 million, facilities of \$17.9 million and other expenditures of \$16.7 million. Additionally, we spent \$36.6 million on the acquisition of the remaining 30% working interest in our properties in Brazil.

Estimated Oil and Gas Reserves

As at December 31, 2012, the estimated proved oil and gas reserves, NAR, were 40.6 MMBOE compared with 34.0 MMBOE as at December 31, 2011 and 23.8 MMBOE as at December 31, 2010.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2012, were 38.5 MMbbl, a 25% increase from the estimated proved oil and NGL reserves as at December 31, 2011. The increase was due primarily to positive technical adjustments for the Costayaco field due to reservoir performance, successful appraisal drilling on the Moqueta field and exploration success with the Ramiriqui-1 well in Colombia. Reserves were also added through development drilling on the Tiê field in the Recôncavo Basin, Brazil and the Proa-2 development well on the Surubi Block in Argentina. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2012 were 14.8 MMbbl and 21.5 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2012, were 12.8 Bcf compared with 18.3 Bcf at December 31, 2011. At December 31, 2012, 61% of proved gas reserves were in the Sierra Nevada Block and 26% were in the Puesto Morales Block. Estimated proved gas reserves, NAR, in the Sierra Nevada Block decreased by 6.0 Bcf during the year ended December 31, 2012 due to technical revisions. Proved gas reserves in the Puesto Morales Block were consistent with the prior year end as new gas reserves were created to replace 2012 production. Estimated probable and possible gas reserves, NAR, as of December 31, 2012 were 5.1 Bcf and 51.7 Bcf, respectively, due to technical revisions in the Sierra Nevada Block.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2011, were 30.9 MMbbl, a 31% increase from the estimated proved reserves as at December 31, 2010. The increase was due to the acquisition of Petrolifera which had reserves in Argentina and Colombia, positive technical revisions to Costayaco reserves (based on reservoir performance), the drilling of additional appraisal wells in the Moqueta field and the acquisition of the 70% working interest ("WI") in Block 155 in Brazil, which more than offset 2011 production of oil and NGLs. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2011 were 10.5 MMbbl and 17.6 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2011, were 18.3 Bcf compared with 1.2 Bcf at December 31, 2010. Estimated probable and possible gas reserves, NAR, as of December 31, 2011 were 25.7 Bcf and 116.5 Bcf, respectively.

Business Environment Outlook

Our revenues have been significantly affected by pipeline disruptions in Colombia and the continuing fluctuations in oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about financial markets and the impact of the worldwide economy on oil demand growth.

We believe that our current operations and 2013 capital expenditure program can be funded from cash flow from existing operations, cash on hand and potential periodic draws from our revolving credit facility. Should our operating cash flow decline further due to unforeseen events, including additional pipeline delivery restrictions in Colombia or a downturn in oil and gas prices, we would examine measures such as further capital expenditure program reductions, issuance of debt, disposition of assets, or issuance of equity. Continuing social uncertainty in the Middle East and North Africa and economic uncertainty in the United States, Europe and China are having an impact on world markets, and we are unable to determine the impact, if any, these events may have on oil prices and demand.

Our future growth and acquisitions may depend on our ability to raise additional funds through equity and debt markets. Should we be required to raise debt or equity financing to fund capital expenditures or other acquisition and development opportunities, such funding may be affected by the market value of shares of our Common Stock. Our ability to utilize our Common Stock to raise capital may be negatively affected by declines in the price of shares of our Common Stock. Also, raising funds by issuing shares or other equity securities would further dilute our existing shareholders, and this dilution would be exacerbated by a decline in our share price. Any securities we issue may have rights, preferences and privileges that are senior to our existing equity securities. Borrowing money may also involve further pledging of some or all of our assets, may require compliance with debt covenants and will expose us to interest rate risk. Depending on the currency used to borrow money, we may also be exposed to further foreign exchange risk. Our ability to borrow money and the interest rate we pay for any money we borrow will be affected by market conditions, and we cannot predict what price we may pay for any borrowed money.

Business Combinations

On October 8, 2012, the Company received regulatory approval and acquired the remaining 30% working interest in four blocks in Brazil pursuant to the terms of a purchase and sale agreement dated January 20, 2012. With the exception of one block which has three producing wells, the remaining blocks are unproved properties. The Company paid initial cash purchase consideration of \$35.5 million. Contingent consideration up to an additional \$3.0 million may be payable dependent on production volumes from the acquired blocks.

On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru. As indicated in the allocation of the consideration transferred, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, we reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, we recognized a gain on acquisition of \$21.7 million in the consolidated statement of operations in the year ended December 31, 2011. The gain reflected the impact on Petrolifera's pre-acquisition market value resulting from their lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

For further details reference should be made to Note 3 of the consolidated financial statements in Item 8 "*Financial Statements and Supplementary Data*".

Consolidated Results of Operations

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
(Thousands of U.S. Dollars)					
Oil and natural gas sales	\$ 583,109	(2)	\$ 596,191	60	\$ 373,286
Interest income	2,078	71	1,216	4	1,174
	585,187	(2)	597,407	60	374,460
Operating expenses	124,903	44	86,497	46	59,446
DD&A expenses	182,037	(21)	231,235	41	163,573
G&A expenses	58,882	(2)	60,389	50	40,241
Other gain	(9,336)	—	—	—	—
Equity tax	—	(100)	8,271	—	—
Financial instruments gain	—	(100)	(1,522)	—	(44)
Gain on acquisition	—	(100)	(21,699)	—	—
Foreign exchange loss (gain)	31,338	—	(11)	(100)	16,838
	387,824	7	363,160	30	280,054
Income before income taxes	197,363	(16)	234,247	148	94,406
Income tax expense	(97,704)	(9)	(107,330)	88	(57,234)
Net income	\$ 99,659	(21)	\$ 126,917	241	\$ 37,172

Production

Oil and NGL's, bbl	5,934,107	(3)	6,118,705	17	5,228,554
Natural gas, Mcf	1,501,070	6	1,411,188	425	268,776
Total production, BOE (1)	6,184,286	(3)	6,353,903	20	5,273,350

Average Prices

Oil and NGL's per bbl	\$ 97.31	1	\$ 96.60	36	\$ 71.19
Natural gas per Mcf	\$ 3.76	3	\$ 3.65	(6)	\$ 3.90

Consolidated Results of Operations per BOE

Oil and natural gas sales	\$ 94.29	—	\$ 93.83	33	\$ 70.79
Interest income	0.34	79	0.19	(14)	0.22
	94.63	1	94.02	32	71.01
Operating expenses	20.20	48	13.61	21	11.27
DD&A expenses	29.44	(19)	36.39	17	31.02
G&A expenses	9.52	—	9.50	25	7.63
Other gain	(1.51)	—	—	—	—
Equity tax	—	(100)	1.30	—	—
Financial instruments gain	—	(100)	(0.24)	—	(0.01)
Gain on acquisition	—	(100)	(3.42)	—	—
Foreign exchange loss (gain)	5.07	-	—	(100)	3.19
	62.72	10	57.14	8	53.10
Income before income taxes	31.91	(13)	36.88	106	17.91
Income tax expense	(15.80)	(6)	(16.89)	56	(10.85)
Net income	\$ 16.11	(19)	\$ 19.99	183	\$ 7.06

(1) Production represents production volumes NAR adjusted for inventory changes.

Consolidated Results of Operations for the Year Ended December 31, 2012, Compared with the Results for the Year Ended December 31, 2011

Net income for the year ended December 31, 2012, was \$99.7 million, a 21% decrease from 2011. On a per share basis, net income decreased to \$0.35 per share basic and diluted from \$0.46 per share basic and \$0.45 per share diluted in 2011. For the year ended December 31, 2012, decreased DD&A, G&A and income tax expenses, the realization of a recovery of previously unrecognized value added tax which occurred upon the completion of a reorganization of companies and their Colombian branches and the absence of the Colombian equity tax expense were more than offset by decreased oil and natural gas sales and increased operating expenses and foreign exchange losses and the absence of the 2011 gain on acquisition. Net income in 2011 included a gain on the acquisition of Petrolifera of \$21.7 million.

Oil and NGL production, NAR and adjusted for inventory changes, for the year ended December 31, 2012, decreased to 5.9 MMbbl compared with 6.1 MMbbl in 2011 due to pipeline disruptions and the effect of a change in the sales point in Colombia. As a result of entering into new oil sales and transportation agreements with Ecopetrol as of February 1, 2012, which changed the sales point of our oil from Orito station to the Port of Tumaco, our oil inventory increased and now includes oil in the OTA pipeline and associated Ecopetrol owned facilities. Production during the year ended December 31, 2012, reflects approximately 162 days of oil delivery restrictions in Colombia.

Average realized oil prices increased by 1% to \$97.31 per bbl from \$96.60 per bbl for the year ended December 31, 2012. We received a premium to West Texas Intermediate ("WTI") in Colombia during the year ended December 31, 2012. WTI oil prices for the year ended December 31, 2012, were \$94.20 per bbl compared with \$95.06 per bbl in 2011. Average Brent oil prices for the year ended December 31, 2012, were \$111.67 per bbl compared with \$111.26 per bbl in 2011.

Revenue and other income for the year ended December 31, 2012, decreased to \$585.2 million from \$597.4 million in 2011 as a result of decreased production, partially offset by increased realized prices.

Operating expenses for the year ended December 31, 2012, were \$124.9 million, or \$20.20 per BOE, compared with \$86.5 million, or \$13.61 per BOE, in 2011. The increase in operating expenses was primarily due to an increase of \$29.3 million in Colombia mainly due to OTA pipeline oil transportation costs of \$3.77 per BOE, previously deducted from realized sales prices and now included as operating costs due to the change in sales point in February 2012, and increased trucking to other sales points due to OTA pipeline disruptions.

DD&A expenses for the year ended December 31, 2012, decreased to \$182.0 million from \$231.2 million in 2011. DD&A expenses for the year ended December 31, 2012, included a \$20.2 million ceiling test impairment in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. DD&A expenses in 2011 included a \$42.0 million ceiling test impairment in our Peru cost center related to drilling costs from a dry well and seismic costs on relinquished blocks and a \$25.7 million ceiling test impairment loss in our Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. On a per BOE basis, the depletion rate decreased by 19% to \$29.44 from \$36.39. The decrease was mainly due to lower impairment charges of \$3.42 per BOE in the year ended December 31, 2012, compared with \$10.65 per BOE in 2011 and increased reserves being only partially offset by increased costs in the depletable base.

G&A expenses for the year ended December 31, 2012, of \$58.9 million decreased by 2% from \$60.4 million in 2011. Increased employee related costs and bank fees reflecting expanded operations were more than offset by increased recoveries, higher capitalized costs in Peru and the absence of expenses related to the 2011 Petrolifera acquisition. G&A expenses in 2011 included \$1.2 million of expenses associated with the acquisition of Petrolifera and \$1.6 million of interest on the Petrolifera debt. G&A expenses per BOE in the year ended December 31, 2012, of \$9.52 were comparable with \$9.50 in 2011.

Other gain in the year ended December 31, 2012, relates to a value added tax recovery resulting from the completion of a reorganization of companies and their Colombian branches in the Colombian reporting segment during the fourth quarter of 2012.

Equity tax in the year ended December 31, 2011, represented a Colombian tax of 6% which was calculated based on our Colombian segment's balance sheet equity at January 1, 2011. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period.

Gain on acquisition of \$21.7 million in the year ended December 31, 2011, related to the Petrolifera acquisition.

For the year ended December 31, 2012, the **foreign exchange loss** was \$31.3 million, of which \$17.1 million was an unrealized non-cash foreign exchange loss. The realized foreign exchange loss in 2012 primarily arose upon payment of 2011 Colombian income tax liabilities. For the year ended December 31, 2011, there was an unrealized non-cash foreign exchange gain of \$2.2 million, but this was almost entirely offset by realized foreign exchange losses. The Colombian Peso strengthened by 9.0% and weakened by 1.5% against the U.S. dollar in the year ended December 31, 2012 and 2011, respectively. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation is the main source of the unrealized exchange losses or gains.

Income tax expense was \$97.7 million for the year ended December 31, 2012, compared with \$107.3 million in 2011. The decrease was primarily due to lower income before tax. The effective tax rate was 50% in the year ended December 31, 2012, compared with 46% in 2011. The higher effective tax rate was primarily due to a non-taxable gain on the acquisition of Petrolifera recorded in 2011, an increase in non-deductible royalty payments, the impact of branch and other foreign loss pick-ups, an increase in the non-deductible foreign currency translation adjustments and other permanent difference in 2012. These factors were partially offset by the impact of foreign taxes as compared with the U.S. statutory rate and a lower valuation allowance in 2012.

For 2012, the differential between the effective tax rate of 50% and the 35% U.S. statutory rate was primarily attributable to non-deductible foreign currency translation adjustments, non-deductible royalty payments, other permanent differences, and an increase in valuation allowances. For 2011, the variance between the effective tax rate of 46% and the 35% U.S. statutory rate was mainly attributable to non-deductible royalty payments and an increase in valuation allowance offset partially by the inclusion of the non-taxable gain on acquisition and the positive impact of branch and other foreign loss pick-ups.

During 2012, a reorganization was completed which resulted in the combination of two Colombian branches. As a result of this merger, certain tax loss balances carried forward were utilized in the current year. The utilization of losses had no net impact on the tax provision as the decrease in the current tax expense was offset by an increase in the deferred tax expense. In addition, as previously discussed, a \$9.3 million gain was recorded on a value added tax receivable which was previously treated as unrecoverable but, as a result of the reorganization transaction, is now considered to be recoverable. For tax purposes, this is a permanent difference as the gain is not taxable in Colombia.

Consolidated Results of Operations for the Year Ended December 31, 2011, Compared with the Results for the Year Ended December 31, 2010

Net income was \$126.9 million, or \$0.46 per share basic and \$0.45 per share diluted, in 2011 compared with \$37.2 million, or \$0.15 per share basic and \$0.14 per share diluted, in 2010. Increased oil and natural gas sales due to increased production and higher realized oil prices, a \$21.7 million gain on the Petrolifera acquisition and the absence of foreign exchange losses were partially offset by a \$42.0 million impairment loss in the Peru cost center, a \$25.7 million impairment loss in the Argentina cost center, a Colombian equity tax of \$8.3 million and increased operating, DD&A and G&A expenses.

Oil and NGL production, NAR and inventory changes, in 2011 increased to 6.1 MMbbl, a 17% improvement compared with 5.2 MMbbl in 2010. The increase was due to improved production from the Moqueta, Jilguero and Juanambu fields, production from Petrolifera and the reduced impact of pipeline interruptions. Petrolifera's oil and NGL production for the period since the acquisition date, NAR, was 0.5 MMbbl. Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010, and February 7, 2011, which reduced sales through the Ecopetrol-operated Trans-Andean oil pipeline ("the OTA pipeline"). During 2010 and February 2011, sections of the OTA pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol for 22 days.

Average realized oil prices in 2011 increased by 36% to \$96.60 per barrel from \$71.19 per barrel in 2010 reflecting higher WTI oil prices and the premium to WTI received in Colombia during 2011. Average WTI for 2011 was \$95.06 as compared with \$79.43 in 2010.

Increased production and higher oil prices resulted in a 60% increase in **revenue and other income** to \$597.4 million for 2011 compared with \$374.5 million in 2010.

Operating expenses for 2011 amounted to \$86.5 million, or \$13.61 per BOE, compared with \$59.4 million or \$11.27 per BOE, in 2010. The increase in operating expenses was mainly due to an increase of \$18.3 million in operating costs in Argentina (\$15.9 million related to properties acquired from Petrolifera), an increase of \$7.7 million in Colombia and \$1.0 million in Brazil as a result of expanded operations.

DD&A expenses for 2011 increased to \$231.2 million compared with \$163.6 million in 2010. DD&A expenses for 2011 includes a \$42.0 million ceiling test impairment for our Peru cost center relating to seismic and drilling costs from two blocks which were relinquished, a \$25.7 million impairment loss in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes and \$18.4 million of depletion, depreciation and accretion related to properties acquired from Petrolifera. DD&A expenses in 2010 included a \$23.6 million ceiling test impairment in our Argentina cost center, of which \$17.9 million related to the abandonment of the GTE.St.VMor-2001 sidetrack operations. The remaining small increase in DD&A was due to higher production levels and increased future development costs included in the depletable base, partially offset by an increase in year-end reserves as compared with 2010. On a BOE basis, DD&A in 2011 was \$36.39 compared with \$31.02 for 2010, representing a 17% increase resulting from ceiling test impairment losses and increased future development costs, partially offset by increased reserves. Impairment charges were \$10.65 per BOE in the year ended December 31, 2011, compared with \$4.48 per BOE in 2010.

G&A expenses of \$60.4 million for 2011 were 50% higher than in 2010 due to increased employee related costs reflecting the expanded operations in all business segments, \$1.2 million of expenses associated with the acquisition of Petrolifera and the inclusion of Petrolifera G&A expenses of \$7.3 million (including interest on bank debt of \$1.6 million, which was retired in August 2011). G&A expenses per BOE increased 25% to \$9.50 per BOE compared with \$7.63 per BOE for 2010 due to the same factors.

Equity tax represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years.

The **financial instruments gain** primarily relates to the fair value assigned to warrants issued in connection with the acquisition of Petrolifera. These warrants expired unexercised during August 2011.

The **gain on acquisition** of \$21.7 million in 2011 relates to the acquisition of Petrolifera. This gain reflects the impact on Petrolifera's pre-acquisition market value of its lack of liquidity and capital resources required to maintain production and reserves and further develop and explore its inventory of prospects.

There were essentially no **foreign exchange gains** in 2011 as a result of an unrealized non-cash foreign exchange gain of \$2.2 million being offset by realized foreign exchange losses. The non-cash foreign exchange gain primarily relates to the translation of deferred tax liabilities. This compares to a foreign exchange loss of \$16.8 million recorded in 2010, of which \$14.4 million was an unrealized non-cash foreign exchange loss. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation results in the recognition of unrealized exchange losses or gains. The Colombian Peso devalued by 1.5% against the U.S. dollar in the year ended December 31, 2011, resulting in an unrealized foreign exchange gain which was offset by realized foreign exchange losses. In 2010, the Colombian Peso strengthened against the U.S. dollar by 6%.

Income tax expense for 2011 was \$107.3 million compared with \$57.2 million in 2010. This represents an increase of 88%, primarily as a result of higher net income in Colombia. For the year ended December 31, 2011, the effective income tax rate was 46% compared with 61% in 2010 due to a decrease in non-taxable foreign currency translation adjustments and the non-taxable gain on acquisition in 2011, partially offset by an increase in the valuation allowance on deferred tax assets mainly in Peru. The variance in the effective tax rates compared with the 35% U.S. statutory rate is attributable to the same factors and other permanent differences.

2013 Work Program and Capital Expenditure Program

In December 2012, we announced the details of our 2013 capital program. We have planned a 2013 capital program of \$363 million consisting of: \$224 million for Colombia; \$67 million for Brazil; \$31 million for Argentina; \$38 million for Peru; and \$3 million associated with corporate activities. Of this, \$202 million is for drilling, \$65 million is for facilities, pipelines and other; \$93 million is for G&G expenditures; and \$3 million is for corporate activities. Of the \$202 million allocated to drilling, approximately \$101 million is for exploration and the balance is for appraisal and development drilling.

Our 2013 work program is intended to create both growth and value by developing existing assets to increase reserves and production levels, the construction of pipelines and facilities in the areas with proved reserves, and maturing our exploration prospects through seismic acquisition and drilling. We are financing our capital program through cash flows from operations, cash on hand and potential periodic draws from our revolving credit facility, while retaining financial flexibility to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds be expended as set forth in our 2013 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Segmented Results – Colombia

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
(Thousands of U.S. Dollars)					
Oil and natural gas sales	\$ 493,615	(9)	\$ 543,999	51	\$ 359,302
Interest income	667	36	492	7	460
	494,282	(9)	544,491	51	359,762
Operating expenses	87,410	50	58,081	15	50,431
DD&A expenses	122,055	(14)	141,133	6	133,728
G&A expenses	23,019	(8)	25,116	65	15,216
Other gain	(9,336)	—	—	—	—
Equity tax	—	(100)	8,271	—	—
Foreign exchange loss (gain)	26,660	—	(1,626)	(109)	17,901
	249,808	8	230,975	6	217,276
Income before income taxes	\$ 244,474	(22)	\$ 313,516	120	\$ 142,486
Production					
Oil and NGL's, bbl	4,785,643	(11)	5,348,885	8	4,944,510
Natural gas, Mcf	154,702	(42)	267,612	—	268,776
Total production, BOE (1)	4,811,427	(11)	5,393,487	8	4,989,306
Average Prices					
Oil and NGL's per bbl	\$ 103.04	2	\$ 101.42	40	\$ 72.45
Natural gas per Mcf	\$ 3.16	(45)	\$ 5.72	47	\$ 3.90
Segmented Results of Operations per BOE					
Oil and natural gas sales	\$ 102.59	2	\$ 100.86	40	\$ 72.01
Interest income	0.14	56	0.09	—	0.09
	102.73	2	100.95	40	72.10
Operating expenses	18.17	69	10.77	7	10.11
DD&A expenses	25.37	(3)	26.17	(2)	26.80
G&A expenses	4.78	3	4.66	53	3.05
Other gain	(1.94)	—	—	—	—
Equity tax	—	(100)	1.53	—	—
Foreign exchange loss (gain)	5.54	—	(0.30)	(108)	3.59
	51.92	21	42.83	(2)	43.55
Income before income taxes	\$ 50.81	(13)	\$ 58.12	104	\$ 28.55

(1) Production represents production volumes NAR adjusted for inventory changes.

Segmented Results of Operations - Colombia for the Year Ended December 31, 2012, Compared with the Results for the Year Ended December 31, 2011

For the year ended December 31, 2012, ***income before income taxes*** was \$244.5 million compared with \$313.5 million in 2011. The decrease was due to lower oil and natural gas sales primarily due to reduced production and increased operating expenses and foreign exchange losses, partially offset by decreased DD&A and G&A expenses, the recognition of a gain relating to the recovery of value added tax and the absence of equity tax.

On February 1, 2012, the sales point for the majority of our oil sales in the Putumayo Basin changed. Ecopetrol now takes title at the Port of Tumaco on the Pacific coast of Colombia rather than at the entry into the OTA pipeline. As a result, our reported oil inventory increased, representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. OTA transportation costs were previously factored into the price we received for oil, but, due to the changes in sales point, are now invoiced separately and included in operating costs. This change resulted in an increase in OTA oil transportation costs of \$3.77 per bbl during year ended December 31, 2012.

Oil and NGL production, NAR and adjusted for inventory changes, for the year ended December 31, 2012, decreased to 4.8 MMbbl compared with 5.3 MMbbl for 2011 due to the impact of pipeline disruptions and the effect of a change in the sales point, which decreased production and increased inventory, partially offset by increased production from new producing wells. Production during the year ended December 31, 2012, reflects approximately 162 days of oil delivery restrictions in Colombia. We continued production at a reduced rate while the OTA pipeline was down, selling a portion of our oil through trucking and storing excess oil. The disruptions resulted in a reduction in oil production of approximately 4,000 BOPD NAR in the year ended December 31, 2012. In 2012, our NAR inventory increased by approximately: 196Mbbbl in Ecopetrol's facilities as a result of the change in sales point and OTA pipeline disruptions; 36Mbbbl in our own storage facilities as a result of OTA pipeline disruptions; and; 110Mbbbl as a result of the terms of a sales agreement with a third party. Sales to a third party increased oil inventory due to a protracted sales cycle whereby the transfer of ownership occurs upon export. Increases in production resulted from the development of the Moqueta field with six producing wells and production in the Garibay Block from the Jilguero-1 and -2 and Melero-1 wells.

As a result of achieving gross field production of five MMbbl in our Costayaco field, we are subject to an additional government royalty payable. This royalty is calculated on 30% of field production revenue over an inflation adjusted trigger point. That trigger point for Costayaco oil was \$31.29 for 2012. Production revenue for this calculation is based on production volumes net of other government royalty volumes. Average government royalties at Costayaco with gross production of 17,000 BOPD and \$100 WTI price per bbl are approximately 27.5%, including the additional government royalty of approximately 20.2%. The Colombian National Hydrocarbon Agency ("ANH") sliding scale royalty at 17,000 BOPD is approximately 9.2% and this royalty is deductible prior to calculating the additional government royalty.

Revenue and other income decreased by 9% to \$494.3 million for the year ended December 31, 2012, as compared with \$544.5 million in 2011.

For the year ended December 31, 2012, the average realized price per bbl for oil increased by 2% to \$103.04 compared with 2011. As discussed above, effective February 1, 2012, the average realized price per bbl in Colombia increased due to the new sales agreement with Ecopetrol. Higher prices were partially offset by the effect of the settlement of a royalty dispute. During the second quarter of 2012, the recognition of additional royalties resulting from an arbitrator's decision on a dispute with a third party relating to the calculation of the third party's net profits interest on 50% of production from the Chaza Block in Colombia resulted in a \$10.9 million revenue reduction. This amount related to July 2009 to May 2012 production. The recognition of this royalty resulted in a \$2.27 per BOE reduction in the average realized price in the year ended December 31, 2012. The decision will increase future net profit interests payable to this third party. The third party royalty settlement represented less than 1% of the reported revenue for the periods under dispute and it is not expected to have a materially different effect on future revenue.

Operating expenses increased by 50% to \$87.4 million for the year ended December 31, 2012, from \$58.1 million in 2011. On a per BOE basis, operating expenses increased by 69% to \$18.17 for the year ended December 31, 2012, from \$10.77 in 2011. As discussed above, effective February 1, 2012, operating expenses per BOE increased due to the \$3.77 per bbl OTA pipeline oil transportation costs now charged as operating costs. Additionally, operating expenses per BOE were higher due to increased trucking as a result of the pipeline disruptions and increased trucking to other sales points, additional maintenance, civil works and environmental activities and a higher percentage of production being from the Moqueta, Jilguero and Melero fields, which have higher per BOE operating costs. Workover costs increased by \$0.44 per BOE compared with 2011 due to increased workovers in the Costayaco, Moqueta and Juanambu fields.

DD&A expenses decreased by 14% to \$122.1 million for the year ended December 31, 2012, from \$141.1 million in 2011. The decrease was primarily due to increased reserves, partially offset by increased costs in the depletable base. On a per BOE basis, DD&A expenses decreased by 3% to \$25.37 for the year ended December 31, 2012.

For the year ended December 31, 2012, **G&A expenses** decreased by 8% to \$23.0 million (\$4.78 per BOE) from \$25.1 million (\$4.66 per BOE) in 2011 due to increased G&A allocations and recoveries.

Other gain in the year ended December 31, 2012, relates to a recovery of previously unrecognized value added tax which occurred upon the completion of a reorganization of companies and their Colombian branches in the Colombian reporting segment during the fourth quarter of 2012. Upon the completion of the reorganization, the combined entity had sufficient revenue to utilize the tax credits.

Equity tax in the year ended December 31, 2011, represented a Colombian tax of 6% on a legislated measure which was based on our Colombian segment's balance sheet equity at January 1, 2011.

For the year ended December 31, 2012, the **foreign exchange loss** was \$26.7 million, of which \$17.1 million was an unrealized non-cash foreign exchange loss. In the year ended December 31, 2011, we incurred a foreign exchange gain of \$1.6 million of which \$0.9 million was an unrealized non-cash foreign exchange gain.

Segmented Results of Operations - Colombia for the Year Ended December 31, 2011, Compared with the Results for the Year Ended December 31, 2010

For the year ended December 31, 2011, **income before income taxes** from Colombia amounted to \$313.5 million compared with income before taxes of \$142.5 million recorded in 2010. The increase is mainly due to increased oil sales due to increased production and higher prices and a foreign exchange gain, partially offset by increases in operating, DD&A and G&A expenses and Colombian equity tax of \$8.3 million.

In 2011, **production of oil and NGLs**, NAR, increased by 8% to 5.3 MMbbl compared with 4.9 MMbbl in 2010. The increase in production was primarily due to the development of the Moqueta field with six producing wells, the commencement of production in the Garibay Block from the Jilguero -1 and -2 wells and increased production in the Guayuyaco Block from the new Juanambu -3 well and a full year of production from Juanambu -2. Production from the Costayaco field was consistent with the prior year. Production from two new wells, Costayaco-12 and -13, was offset by the effects of reservoir management intended to slow production declines.

Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010, and February 7, 2011, which reduced sales through the OTA pipeline. During 2010, sections of the OTA pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol for 29 days (7 days in June and 22 days in September).

Revenue and other income in 2011 increased by 51% to \$544.5 million compared with 2010. Oil and natural gas sales were positively impacted by higher net realized oil prices in 2011 and increased production. The average net realized price for oil in 2011 was \$101.42 per barrel, an increase of 40% from 2010. We received a premium to WTI during 2011 related to Colombian Pacific Blend prices.

Operating expenses for the year ended December 31, 2011, increased to \$58.1 million, or \$10.77 per BOE, from \$50.4 million, or \$10.11 per BOE, in 2010. Operating expenses per BOE were higher in 2011 due to long-term testing and slickline service costs partially offset by reduced transportation and workover costs. Significant long-term testing costs were incurred at Jilguero -1 and slickline service costs were incurred at Costayaco and Moqueta. Transportation costs were 11% lower than the prior year due to lower trucking costs as a result of the reduced impact of pipeline disruptions and pipeline pumping optimization. Workover costs were 45% lower than the prior year mainly due to fewer workovers in the Chaza Block. Petrolifera's operating expenses for the post acquisition period were \$1.2 million.

For 2011, **DD&A expenses** increased to \$141.1 million from \$133.7 million in 2010. Petrolifera's DD&A expense for the post acquisition period was \$4.3 million. The remainder of the increase was attributable to higher production levels partially offset by a small reduction in the depletion rate to \$26.17 per BOE compared with \$26.80 per BOE in 2010.

G&A expenses increased to \$25.1 million (\$4.66 per BOE) from \$15.2 million (\$3.05 per BOE) in 2010. The increase was mainly due to increased salaries and stock-based compensation resulting from an increased headcount, the inclusion of Petrolifera's G&A expense of \$3.2 million and consulting fees related to expanded operations.

Equity tax of \$8.3 million in 2011 represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period.

The results for 2011 include a **foreign exchange gain** of \$1.6 million, of which \$0.9 million is an unrealized non-cash foreign exchange gain on the translation of Colombian peso denominated deferred taxes to the U.S. dollar functional currency. For 2010, the foreign exchange loss was \$17.9 million, of which \$14.6 million was unrealized.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the year ended December 31, 2012, were \$153.3 million. The following table provides a breakdown of capital expenditures in the three years ended December 31, 2012:

(Millions of U.S. Dollars)	Year Ended December 31,		
	2012	2011	2010
Drilling and completions	\$ 103.1	\$ 105.3	\$ 60.2
Facilities and equipment	26.3	33.0	25.2
G&G	14.5	30.0	22.0
Other	9.4	34.3	(1.9)
	\$ 153.3	\$ 202.6	\$ 105.5

The significant elements of our 2012 capital program in Colombia were:

- On the Chaza Block (100% WI, operated), we drilled and completed the Costayaco-15 and Costayaco-16 development wells and drilled the Costayaco-17 development well in the Costayaco field. We also drilled and completed initial testing of the Moqueta-7 development well and commenced drilling the Moqueta-8 development well in the Moqueta field.
- Together with our partner, we successfully drilled and tested the Ramiriqui-1 oil exploration well on the Llanos-22 Block (45% WI, non-operated).
- We drilled the Bordon-1 oil exploration well on the Garibay Block (50% WI, non-operated), the Florida West exploration well on the Sierra Nevada Block (100% WI, operated) and the La Vega Este-1 oil exploration well on the Azar Block (100% WI, operated). These wells were plugged and abandoned. We also commenced drilling the Turpial-1 oil exploration well on the Turpial Block (50% WI, operated).
- We acquired 3-D seismic on the Costayaco, Moqueta and Verdayaco fields in the Chaza Block, the Guayuyaco Block (70% WI, operated), the Magdalena Block (100% WI, operated), the Putumayo 1 Block (55% WI, operated) and the Rumiayaco Block (100% WI, operated) and conducted surface and subsurface geological studies on the Cauca 6 Block (100% WI, operated) and Cauca 7 Block (100% WI, operated).

- We also continued facilities work at the Costayaco and Moqueta fields.

During the fourth quarter of 2012, we were the successful bidder in the 2012 Colombia Bid Round on the Sinu-1 and Sinu-3 Blocks of the Sinu Basin in northern Colombia. We hold a 60% operated WI in the Sinu-1 Block and a 51% operated WI in the Sinu-3 Block.

Outlook - Colombia

The 2013 capital program in Colombia is \$224 million with \$119 million allocated to drilling, \$39 million to facilities and pipelines and \$66 million for G&G expenditures.

Our planned work program for 2013 in Colombia includes drilling one gross oil exploration well on each of the Chaza and Putumayo-1 Blocks (100 % WI, operated) and two gross exploration wells on the Guayuyaco Block (70% WI, operated). We plan to drill six gross development wells and convert an existing well on the Garibay Block (50 % WI, non-operated) to a water injector well. Development wells are planned for the Chaza (both Costayaco and Moqueta fields) and Llanos-22 Blocks.

We also plan to acquire 2-D seismic on the Cauca-6, Cauca-7, Putumayo-10, Magdalena, Piedemonte Norte and Piedemonte Sur Blocks and 3-D seismic on the Garibay and Putumayo-1 Blocks. Facilities work is also planned for the Chaza, Garibay and Santana Blocks.

Segmented Results – Argentina

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
(Thousands of U.S. Dollars)					
Oil and natural gas sales	\$ 79,642	6.6	\$ 48,016	243	\$ 13,984
Interest income	355	438	6.6	154	26
	79,997	6.6	48,082	243	14,010
Operating expenses	32,696	21	27,076	207	8,808
DD&A expenses	31,466	(31)	45,506	5.5	29,416
G&A expenses	12,159	5.6	7,805	172	2,868
Foreign exchange loss	2,616	693	330	100	165
	78,937	(2)	80,717	9.6	41,257
Income (loss) before income taxes	\$ 1,060	(103)	\$ (32,635)	20	\$ (27,247)
Production					
Oil and NGL's, bbl	1,047,265	44	726,762	156	284,044
Natural gas, Mcf	1,346,368	18	1,143,576	—	—
Total production, BOE (1)	1,271,660	39	917,358	223	284,044
Average Prices					
Oil and NGL's per bbl	\$ 71.12	16	\$ 61.10	24	\$ 49.23
Natural gas per Mcf	\$ 3.83	21	\$ 3.16	—	\$ —
Segmented Results of Operations per BOE					
Oil and natural gas sales	\$ 62.63	20	\$ 52.34	6	\$ 49.23
Interest income	0.28	300	0.07	(22)	0.09
	62.91	20	52.41	6	49.32
Operating expenses	25.71	(13)	29.52	(5)	31.01
DD&A expenses	24.74	(50)	49.61	(52)	103.56
G&A expenses	9.56	12	8.51	(16)	10.10
Foreign exchange loss	2.06	472	0.36	(38)	0.58
	62.07	(29)	88.00	(39)	145.25
Income (loss) before income taxes	\$ 0.84	(102)	\$ (35.59)	(63)	\$ (95.93)

(1) Production represents production volumes NAR adjusted for inventory changes.

Segmented Results of Operations - Argentina for the Year Ended December 31, 2012, Compared with the Results for the Year Ended December 31, 2011

For the year ended December 31, 2012, **income before income taxes** in Argentina was \$1.1 million compared with loss before taxes of \$32.6 million in 2011. In 2011, a ceiling test impairment charge of \$25.7 million was recorded in the Argentina cost center. In 2012, increased oil and natural gas sales and the absence of the impairment charge more than offset increased operating and G&A expenses and foreign exchange losses.

Total production of oil and gas from the Argentina segment increased by 39% to 1.3 MMBOE, NAR and adjusted for inventory changes, for the year ended December 31, 2012, compared with 0.9 MMBOE in 2011. The acquisition of Petrolifera on March 18, 2011, added seven blocks in the Neuquen Basin, including production from four blocks, to the Argentina segment. Production in the year ended December 31, 2012, included Petrolifera production of 0.7 MMBOE, NAR and adjusted for inventory changes, which was a 40% increase from 0.5 MMBOE in 2011 due to a full 12 months of production.

Oil and NGL production, NAR and adjusted for inventory changes, increased 44% to 1.0 MMbbl for the year ended December 31, 2012, compared with 0.7 MMbbl in 2011. The increase was primarily due to production from the Proa-2 well, in the Surubi Block, which began production in April 2012.

Natural gas production, NAR, was 1.3 Bcf in the year ended December 31, 2012, compared with 1.1 Bcf in 2011. The increase was mainly attributable to a full year of production from Petrolifera's properties.

Revenue and other income increased by 66% to \$80.0 million for the year ended December 31, 2012, compared with \$48.1 million in 2011, due to increased production volumes and increased prices.

Average oil prices increased by 16% in the year ended December 31, 2012, compared with 2011. Due to the Argentina regulatory regime, the average oil price we received for production from our blocks during the year ended December 31, 2012, was \$71.12 per bbl. Currently most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis. During 2012, we were able to negotiate higher oil prices with refineries as a result of the Argentina government's decision to allow an increase in domestic petroleum product prices; however, prices have now stabilized.

Operating expenses increased by 21% to \$32.7 million for the year ended December 31, 2012, compared with \$27.1 million in 2011. The increase was due to higher production volumes. On a per BOE basis, operating expenses decreased by 13% to \$25.71 for the year ended December 31, 2012, from \$29.52 in 2011. The decrease in operating costs on a per BOE basis was due to increased production from the Surubi Block, which has lower operating costs per BOE due to high volumes produced.

DD&A expenses decreased by 31% to \$31.5 million for the year ended December 31, 2012, compared with \$45.5 million in 2011. DD&A expenses in 2011 included a ceiling test impairment charge for the Argentina cost center of \$25.7 million. The 2011 impairment loss resulted from an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. In 2012, the impact of the absence of the impairment charge was partially offset by the impact of higher production volumes. On a per BOE basis, DD&A expenses were \$24.74 for the year ended December 31, 2012, 50% lower than DD&A expenses in 2011 of \$49.61 mainly due to the ceiling test impairment charge of \$ 28.02 per BOE in 2011.

G&A expenses were \$12.2 million (\$9.56 per BOE) in the year ended December 31, 2012, compared with \$7.8 million (\$8.51 per BOE) in 2011. For the year ended December 31, 2012, G&A expenses increased due to a \$1.9 million loss recorded against a value added tax receivable balance due from a former partner and increased salaries related expenses due to an increased headcount from expanded operations. G&A expenses in the year ended December 31, 2011, included \$1.6 million of interest expense on debt acquired on the Petrolifera acquisition which was repaid in August 2011, when Argentina's regulatory requirements allowed its repayment.

For the year ended December 31, 2012, the **foreign exchange loss** was \$2.6 million, compared with \$0.3 million in 2011. The loss primarily relates to realized foreign exchange losses on monetary assets in Argentina during the year. The Argentina Peso weakened by 14% and 9% against the U.S. dollar in the year ended December 31, 2012, and 2011, respectively, and the net asset balance exposed to foreign exchange losses was higher throughout 2012 as compared to 2011 as a result of increased production and sales.

Segmented Results of Operations - Argentina for the Year Ended December 31, 2011, Compared with the Results for the Year Ended December 31, 2010

For the year ended December 31, 2011, **loss before income taxes** in Argentina amounted to \$32.6 million compared with \$27.2 million in 2010. Loss before income tax included a ceiling test impairment charge for the Argentina cost center of \$25.7 million in 2011 and \$23.6 million in 2010. In 2011, increased oil and natural gas sales were more than offset by increased operating, depletion and G&A expenses and an increase in the foreign exchange loss. Results of the Argentina segment were significantly affected by the inclusion of Petrolifera's results since the acquisition date. The impact of Petrolifera on the financial and operational results of the Argentina segment is discussed below.

Oil and NGL production, NAR, increased 156% to 0.7 MMbbl compared with 0.3 MMbbl for 2010. The increase resulted from the inclusion of Petrolifera production of 0.5 MMbbl, NAR, in 2011.

Natural gas sales, NAR, relate solely to Petrolifera's properties. Natural gas sales amounted to 1.1 Bcf in 2011. Overall, total production of oil and gas from the Argentina segment increased by 223% to 0.9 MMBOE in 2011. Due to the Argentina regulatory regime, the average oil price we received for production from our blocks during 2011 was approximately \$61.10 per barrel. Currently most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis.

Revenue and other income increased by 243% to \$48.1 million in 2011 compared with \$14.0 million in 2010. The increase was primarily due to higher production due to the inclusion of Petrolifera's oil and gas production and increased prices. Average regulated oil prices increased by 24% in 2011 compared with 2010. The Argentina segment realized \$0.6 million from the sale of Petroleum Plus program credits during the fourth quarter of 2011. These credits are granted by the Argentina government to companies for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields.

Operating expenses in 2011 amounted to \$27.1 million compared with \$8.8 million in 2010. Petrolifera's operating expenses were \$15.9 million in 2011. Operating expenses were \$29.52 per BOE in 2011 compared with \$31.01 per BOE in 2010. Transportation costs decreased by \$1.91 per BOE a result of a higher percentage of production being from blocks with lower per BOE transportation costs, such as the Puesto Morales Block.

DD&A expenses in 2011 were \$45.5 million compared with \$29.4 million in 2010. DD&A expenses included a ceiling test impairment charge for the Argentina cost center of \$25.7 million in 2011 and \$23.6 million in 2010. The impairment loss in 2011 resulted from an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. The impairment loss in 2010 included \$17.9 million relating to the abandonment of the sidetrack operations at the GTE.St.VMor-2001 well and \$5.2 million resulting from reduced reserves due to increases in estimated future operating costs. Petrolifera's depreciation, depletion and accretion expense was \$14.0 million in 2011. DD&A expenses per BOE in 2011 were \$49.61, significantly lower than DD&A expenses in 2010 of \$103.56 due to the ceiling test impairment charge of \$83.08 per BOE in 2010 compared with \$28.02 in 2011.

G&A expenses in 2011 were \$7.8 million compared with \$2.9 million in 2010. The increase was primarily due to the inclusion of Petrolifera's G&A for the period after acquisition (\$3.2 million, including interest expense on bank debt of \$1.6 million which was repaid in August 2011) and increased headcount and consulting fees as a result of expanded operations.

Capital Program - Argentina

Capital expenditures in our Argentina segment during the year ended December 31, 2012, were \$40.7 million. Capital expenditures in 2012 included drilling of \$31.9 million, G&G expenditures of \$4.1 million, facilities of \$2.3 million and other expenditures of \$2.4 million.

The significant elements of our 2012 capital program in Argentina were:

- We successfully drilled and completed the Proa-2 development well on the Surubi Block (85% WI, operated). This well began production in April 2012.
- We drilled and completed seven development wells and commenced drilling an additional two development wells on the Puesto Morales Block (100% WI, operated). We completed one development well on the Rinconada Sur Block (100% WI, operated) and, together with our partner, we drilled three gross development wells on the Rinconada Norte Block (35% WI, non-operated). One of the Rinconada Norte Block development wells was completed during the year and two were in progress at year-end
- On the Rinconada Norte Block, together with our partner we drilled four gross exploration wells. One exploration well was producing at year-end, one was plugged and abandoned and two were under evaluation. On the Puesto Guevara Block, we drilled one exploration well, which was plugged and abandoned, and we subsequently relinquished our interest in this block.
- On the Puesto Morales Block we also continued a well workover program, commenced a waterflood program and performed facility upgrades.

Outlook – Argentina

The 2013 capital program in Argentina is \$31 million with \$19 million allocated to drilling, \$6 million to facilities and pipelines, and \$6 million to G&G expenditures.

Our planned work program for 2013 in Argentina includes drilling one gross exploration well on the Santa Victoria Block (increased from 50% to 100% WI, subject to government approval, operated), five development wells on the Puesto Morales Block and workovers on existing wells. We also plan to acquire G&G on the Puesto Morales Block and the Valle Morado Block and perform facilities work on the El Chivil Block.

Segmented Results – Peru

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
(Thousands of U.S. Dollars)					
Interest income	\$ 49	(65)	\$ 140	—	\$ —
Operating expenses	160	(50)	\$ 322	5 6	207
DD&A expenses	1,234	(97)	42,035	—	40
G&A expenses	4,573	8	4,249	269	1,153
Foreign exchange (gain) loss	(425)	9 6	(217)	(823)	30
	<u>5,542</u>	<u>(88)</u>	<u>46,389</u>	<u>3,144</u>	<u>1,430</u>
Loss before income taxes	<u>\$ (5,493)</u>	<u>(88)</u>	<u>\$ (46,249)</u>	<u>3,134</u>	<u>\$ (1,430)</u>

Segmented Results of Operations - Peru for the Year Ended December 31, 2012, Compared with the Results for the Years Ended December 31, 2011, and December 31, 2010

DD&A expenses for the year ended December 31, 2011, included \$42.0 million of impairment charges relating to drilling costs from a dry well and seismic costs on blocks which were relinquished.

G&A expenses were \$4.6 million in the year ended December 31, 2012, compared with \$4.2 million in 2011. The increase was due to higher salaries expense resulting from expanded operations partially offset by increased capitalized costs. The increase in G&A expenses in 2011 compared with 2010 was due to higher salaries, stock-based compensation and consulting fees resulting from increased activity.

Capital Program – Peru

Capital expenditures in our Peruvian segment for the year ended December 31, 2012, were \$62.9 million. Capital expenditures in 2012 included drilling of \$31.1 million, acquisitions of \$12.5 million, G&G expenditures of \$17.4 million and other expenditures of \$1.9 million.

The significant elements of our 2012 capital program in Peru were:

- On Block 95 (100% WI, operated), we completed civil construction of a drilling platform and dock facility and began drilling the Breña Norte 95-2-1XD exploration well on December 15, 2012. We also applied for a variety of permits in preparation for drilling the oil exploration well and for future seismic programs.
- On Block 123 and Block 129, we assumed 100% WI, subject to government approval, and we were appointed operator as of January 1, 2013.
- We acquired 2-D seismic on Block 123 and Block 129.
- On Block 107 (100% WI, operated), we acquired a carried working interest that was held by a third party and advanced permitting for drilling and, on Block 133 (100% WI, operated), we performed G&G studies.

Outlook - Peru

The 2013 capital program in Peru is \$38 million with \$21 million allocated to drilling, \$2 million for facilities and \$15 million for G&G expenditures.

In 2013, we completed drilling the Breña Norte 95-2-1XD exploration well on Block 95 and obtained initial well-log results, which indicated an oil saturated reservoir. We plan to extend the exploration well with a horizontal leg to initiate long-term testing. Timing for initiation of the long-term testing has not been determined yet, but it is expected to commence within a period of 12 months, subject to facilities upgrade, and execution of crude oil transportation and delivery agreements.

Our planned work program for 2013 also includes the acquisition of 2-D seismic on Block 107, the commencement of an aeromagnetic and aerogravity survey and Environmental Impact Assessments on Block 133 and obtaining the necessary environmental and social permits to implement future seismic programs on Block 95, Block 123 and Block 129.

Segmented Results - Brazil

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
(Thousands of U.S. Dollars)					
Oil and natural gas sales	\$ 9,852	136	\$ 4,176	—	\$ —
Interest income	607	623	84	9	77
	10,459	146	4,260	5,432	77
Operating expenses	4,637	356	1,018	—	—
DD&A expenses	26,300	—	1,819	—	77
G&A expenses	2,092	(54)	4,542	74	2,609
Foreign exchange loss	1,973	160	759	(285)	(411)
	35,002	330	8,138	258	2,275
Loss before income taxes	\$ (24,543)	533	\$ (3,878)	76	\$ (2,198)

Production (1)

Oil and NGL's, bbl	101,199	135	43,058	—	—
--------------------	----------------	-----	--------	---	---

Average Prices

Oil and NGL's per bbl	\$ 97.35	—	\$ 96.99	—	\$ —
-----------------------	----------	---	----------	---	------

Segmented Results of Operations per BOE

Oil and natural gas sales	\$ 97.35	—	\$ 96.99	—	\$ —
Interest income	6.00	208	1.95	—	—
	103.35	4	98.94	—	—
Operating expenses	45.82	94	23.64	—	—
DD&A expenses	259.88	515	42.25	—	—
G&A expenses	20.67	(80)	105.49	—	—
Foreign exchange loss	19.50	11	17.63	—	—
	345.87	83	189.01	—	—
Loss before income taxes	\$ (242.52)	169	\$ (90.07)	—	\$ —

(1) Production represents production volumes NAR adjusted for inventory changes.

Segmented Results of Operations - Brazil for the Year Ended December 31, 2012, Compared with the Results for the Years Ended December 31, 2011, and December 31, 2010

For the year ended December 31, 2012, *loss before income taxes* was \$24.5 million compared with \$3.9 million in 2011. Loss before income taxes in 2012 included a ceiling test impairment loss of \$20.2 million relating to seismic and drilling costs on Block BM-CAL-10.

Oil and natural gas sales and **operating expenses** represented sales and operating expenses from Block 155 in the Tiê field in the onshore Recôncavo Basin. We began recording revenue from production from this block on June 15, 2011, the date regulatory approval was received for the purchase of our 70% working interest in the block. In 2012, production was shut in between the expiry of the long-term test phase on July 31, 2012, and the declaration of commerciality for the Tiê field. Production recommenced on September 21, 2012, after the receipt of regulatory approval. We were also subject to gas flaring restrictions during the third quarter of 2012, which were subsequently eased and are subject to re-approval for periods after December 31, 2013. We increased our working interest in Block 155 to 100% in October 2012.

Average Brent oil prices for the year ended December 31, 2012, were \$111.67 per bbl (year ended December 31, 2011 - \$111.26 per bbl). The price we receive in Brazil is at a discount to Brent due to a refining discount.

DD&A expenses in the year ended December 31, 2012, included a ceiling test impairment loss of \$20.2 million. The impairment loss related to seismic and drilling costs on Block BM-CAL-10. The remainder of the increase is due to increased reserves being more than offset by increased costs in the depletable base.

G&A expenses were \$2.1 million in the year ended December 31, 2012, compared with \$4.5 million in 2011 and \$2.6 million in 2010. We began recognizing production in Brazil in June 2011 upon receipt of regulatory approval. This resulted in a significant increase in the costs that were directly attributable to operations and exploration and development and a corresponding reduction in G&A expenses in 2012 compared with 2011.

Capital Program – Brazil

Capital expenditures in our Brazilian segment during the year ended December 31, 2012, were \$55.2 million. Capital expenditures in 2012 included drilling of \$52.0 million, facilities of \$1.1 million, G&G expenditures of \$0.2 million and \$1.9 million of other expenditures. Additionally, we spent \$36.6 million (including contingent consideration) on the acquisition of the remaining 30% working interest in our properties in Brazil, which was accounted for as a business combination.

The significant elements of our 2012 capital program in Brazil were:

- On October 8, 2012, the Company received regulatory approval and acquired the remaining 30% working interest in Blocks REC-T-129, REC-T-142, REC-T-155, and REC-T-224 pursuant to the terms of a purchase and sale agreement dated January 20, 2012. The purchase consideration was \$35.5 million. Contingent consideration of up to an additional \$3.0 million may be payable dependent on production volumes from the acquired blocks.
- We drilled and completed two gross development wells, 3-GTE-03-BA and 4-GTE-04-BA, in the Tiê field on Block REC-T-155 (100% WI, operated) and drilled a horizontal oil exploration well, 1-GTE-05HP-BA, on Block REC-T-142 (100% WI, operated).
- We received regulatory approval for our farm-in on Block BM-CAL-7 (10% WI, non-operated) in the offshore Camamu Basin. Purchase consideration of \$0.7 million was paid and the assignment became effective on April 3, 2012. We also purchased an existing 3-D seismic program on this block.
- During 2011, we entered into a farm-out agreement with Statoil do Brasil Ltda. (“Statoil”) pursuant to which we would receive an assignment from Statoil of a non-operated 15% working interest in Block BM-CAL-10. During the first quarter of 2012, in accordance with the terms of the farm-out agreement for Block BM-CAL-10, we gave notice to Statoil that we would not enter into and assume our share of the work obligations of the second exploration period of the block. As a result, the farm-out agreement terminated and we will not receive any interest in this block. Pursuant to the farm-out agreement, we were obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to a well that was drilled during the term of the farm-out agreement. The notice of withdrawal was a trigger for payment of amounts that would otherwise have been due if the farm-out agreement had closed and we had acquired a working interest. We recorded \$23.8 million of capital expenditures in relation to the Block BM-CAL-10 farm-out agreement in 2012.

Outlook – Brazil

The 2013 capital program in Brazil is \$67 million with \$43 million allocated to drilling, \$18 million to facilities and pipelines and \$6 million for G&G and other expenditures.

Our planned work program for 2013 in Brazil includes drilling two horizontal sidetrack oil exploration wells on Block REC-T-155 and Block REC-T-142 (100% WI and operator), additional completion work on the 3-GTE-03-BA and 3-GTE-04-BA producing wells in the Tiê field and fracture stimulation operations on Block REC-T-142. We also plan to perform facilities and pipeline work on Block REC-T-155.

Results - Corporate Activities

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
(Thousands of U.S. Dollars)					
Interest income	\$ 400	(8)	\$ 434	(29)	611
DD&A expenses	982	32	742	138	312
G&A expenses	17,039	(9)	18,677	2	18,395
Financial instruments gain	—	(100)	(1,522)	—	(44)
Gain on acquisition	—	(100)	(21,699)	—	—
Foreign exchange (gain) loss	514	(31)	743	(188)	(847)
	18,535	(706)	(3,059)	(117)	17,816
(Loss) income before income taxes	\$ (18,135)	(619)	\$ 3,493	(120)	\$ (17,205)

Results of Operations - Corporate Activities for the Year Ended December 31, 2012, Compared with the Results for the Years Ended December 31, 2011, and December 31, 2010

G&A expenses in the year ended December 31, 2012, were \$17.0 million compared with \$18.7 million in 2011. In the year ended December 31, 2012, increases in salaries due to expanded operations were more than offset by an increase in the amount of costs recovered from business units, a reduction in consulting costs and the absence of Petrolifera acquisition costs (\$1.2 million in the year ended December 31, 2011). In 2011, the increase in G&A expenses compared to 2010 related to increased salaries and stock-based compensation and increased consulting charges due to expanded operations in all countries and Petrolifera acquisition costs.

Gain on acquisition in the year ended December 31, 2011, related to the acquisition of Petrolifera.

Liquidity and Capital Resources

At December 31, 2012, we had cash and cash equivalents of \$212.6 million compared with \$351.7 million at December 31, 2011, and \$355.4 million at December 31, 2010.

We believe that our cash resources, including cash on hand, cash generated from operations and our revolving credit facility, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2013, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc., in interest earning current accounts or are invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At December 31, 2012, 89% of our cash and cash equivalents was held by our foreign subsidiaries. This balance is not available to fund domestic operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The governments in Brazil and Argentina require us to register funds that enter and exit the country with the central bank in each country. In Brazil, Argentina and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in the Special Exchange Regime, which allows for the deposit of our revenue to our branch offshore Colombia in U.S. dollars. Beginning in 2013, transfer of branch profits are considered as dividends subject to a 25% tax but only in the case where those dividends have not already been subject to Colombian tax. We do not currently expect that this change in Colombian law will have a material consequence to us.

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentine subsidiaries to make dividends or loan payments to us. At December 31, 2012, \$16.4 million, or 8%, of our cash and cash equivalents was deposited with banks in Argentina. We expect to use these funds for the 2013 Argentina work program and operations.

Effective July 30, 2010, through our wholly-owned subsidiary, Solana Resources Limited ("Solana"), we established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve-based facility has a maximum borrowing base of up to \$100 million and is supported by the present value of our Colombian petroleum reserves of two of our subsidiaries with operating branches in Colombia – Gran Tierra Energy Colombia Ltd. and Petrolifera Petroleum Exploration (Colombia) Ltd, and our subsidiary in Brazil - Gran Tierra Energy Brasil Ltda. The initial committed borrowing base was \$20 million and, effective August 2, 2012, the committed borrowing base was increased to \$50 million. Effective February 15, 2013, the borrowing base was increased to \$100 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. On May 17, 2012, BNP Paribas sold Solana's credit facility to Wells Fargo Bank National Association, as part of the sale of its North American reserve-based lending business. At December 31, 2012, and December 31, 2011, we had not drawn down any amounts under this facility.

Cash Flows

During the year ended December 31, 2012, our cash and cash equivalents decreased by \$139.1 million as a result of cash used in investing activities of \$299.7 million, partially offset by cash provided by operating activities of \$156.3 million and cash provided by financing activities of \$4.3 million.

Cash provided by operating activities in the year ended December 31, 2012, was primarily affected by increased operating expenses and realized foreign exchange losses and a \$167.4 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets increased by \$56.7 million due to the change in the timing of collection of Ecopetrol receivables, new customers in Colombia and increased oil and gas sales in Argentina; inventory increased by \$18.2 million primarily due to a change in the sales point under new sales agreements with Ecopetrol and increased sales to other third parties with different sales points due to the timing of the transfer of risks in Colombia; accounts payable and accrued liabilities decreased by \$8.4 million due to the payment of royalties and reduced royalties payable resulting from lower production, partially offset by increased operating cost and other payables as a result of increased activity in all business units; and taxes receivable and payable decreased by \$83.7 million as a result of a decrease in taxes payable due utilization of tax losses and tax deductions resulting from a corporate reorganization, and lower taxable income in Colombia, partially offset by an increase in taxes receivable due to value added tax and income tax recoveries in Colombia generated upon completion of the same corporate reorganization.

Net cash provided by operating activities in the year ended December 31, 2011, was positively affected by increased production and improved oil prices and a decrease in non-cash working capital. These positive contributions were partially offset by increased operating and G&A expenses to support expanded operations. In year ended December 31, 2010, net cash provided by operating activities was positively affected by the increases in oil production and prices, offset by higher receivables related to oil sales.

Cash outflows from investing activities in the year ended December 31, 2012, included capital expenditures of \$276.1 million and cash paid for the 30% working interest acquisition in Brazil of \$35.5 million, partially offset by a decrease in restricted cash of \$11.9 million related to this same acquisition. Cash outflows from investing activities in the year ended December 31, 2011, included capital expenditures of \$333.2 million and an increase in restricted cash of \$10.2 million, partially offset by proceeds on sale of asset-backed commercial paper ("ABCP") of \$22.7 million, \$7.7 million cash acquired through the Petrolifera acquisition and \$4.5 million of proceeds from disposition of oil and gas properties. Cash outflows from investing activities in the year ended December 31, 2010, primarily related to capital expenditures, partially offset by proceeds from the sale of an overriding royalty right.

Cash provided by financing activities in the years ended December 31, 2012, 2011 and 2010 related to proceeds from issuance of shares of Common Stock upon the exercise of stock options and, in 2011, was more than offset by the settlement of \$31.3 million of bank debt and \$22.8 million of an ABCP line of credit. Both the bank debt and the ABCP line of credit were acquired through the Petrolifera acquisition.

Off-Balance Sheet Arrangements

As at December 31, 2012, 2011 and 2010 we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of December 31, 2012:

	Year ending December 31						
	Total	2013	2014	2015	2016	2017	Thereafter
(Thousands of U.S. Dollars)							
Oil transportation services	\$ 28,354	\$ 5,077	\$ 3,405	\$ 3,405	\$ 3,405	\$ 3,405	\$ 9,657
Drilling and G&G	40,524	38,171	2,353	—	—	—	—
Completions	26,188	14,699	7,368	4,121	—	—	—
Facility construction	18,484	11,623	6,861	—	—	—	—
Operating leases	4,115	1,928	1,706	477	4	—	—
Software and telecommunication	1,744	1,538	74	9	123	—	—
Consulting	1,592	1,592	—	—	—	—	—
	\$ 121,001	\$ 74,628	\$ 21,767	\$ 8,012	\$ 3,532	\$ 3,405	\$ 9,657

Total contractual obligations at December 31, 2011, were \$146.2 million, and the decrease in 2012 was due to the amortization of transportation contracts in Colombia, amortization of information technology contracts and operating leases, and the completion of the Moqueta facilities construction in 2012 partially offset by drilling and completion commitments for Block 95 in Peru.

At December 31, 2012, we had provided promissory notes totaling \$34.2 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Related Party Transactions

On January 12, 2011, we entered into an agreement to sublease office space to a company of which our President and Chief Executive Officer serves as an independent director. The term of the sublease ran from February 1, 2011, to January 30, 2013, and the sublease payment was \$4,500 per month plus approximately \$4,700 of operating and other expense; however, the sublease was terminated on October 31, 2012, and we are now occupying this office space.

On August 7, 2012, we entered into a contract related to the Brazil drilling program with a company for which one of our directors is a shareholder (less than 10% shareholding) and director. During the year ended December 31, 2012, \$1.7 million was incurred and capitalized under this contract and at December 31, 2012, \$1.1 million was included in accounts payable relating to this contract. Similarly, on August 3, 2010, we entered into a contract related to the Peru drilling program with the same company and \$2.8 million was incurred and capitalized under this contract during the year ended December 31, 2011, and at December 31, 2011, \$nil was included in accounts payable relating to this contract.

On February 1, 2009, we entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was \$8,000 per month plus approximately \$4,700 for operating and other expenses.

Critical Accounting Policies and Estimates

The preparation of financial statements under GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as well as the revenues and expenses reported and disclosure of contingent liabilities. Changes in these estimates related to judgments and assumptions will occur as a result of changes in facts and circumstances or discovery of new information, and, accordingly, actual results could differ from amounts estimated.

On a regular basis we evaluate our estimates, judgments and assumptions. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material. The areas of accounting and the associated critical estimates and assumptions made are discussed below.

Full Cost Method of Accounting, Proved Reserves, DD&A and Impairments of Oil and Gas Properties

We follow the full cost method of accounting for our oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 to our annual consolidated financial statements.

Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations ("ARO"), and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The ceiling test limits pooled costs to the aggregate of the discounted estimated after-tax future net revenues from proved oil and gas properties, plus the lower of cost or estimated fair value of unproved properties less any associated tax effects.

If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expenses in future periods. The ceiling limitation is imposed separately for each country in which we have oil and gas properties. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Our estimates of proved oil and gas reserves are a major component of the depletion and full cost ceiling calculations. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the amount and timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the United States as prescribed by the Society of Petroleum Engineers. Reserve estimates are evaluated at least annually by independent qualified reserves consultants.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2012, ceiling tests were based on wellhead prices per BOE as of the first day of each month within that twelve month period of \$103.57 for Colombia, \$66.12 for Argentina and \$95.38 for Brazil.

Because the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. Historical oil and gas prices for any particular 12-month period, can be either higher or lower than our price forecast. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Our Reserves Committee oversees the annual review of our oil and gas reserves and related disclosures. The Board meets with management periodically to review the reserves process, results and related disclosures and appoints and meets with the independent reserves consultants to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

We assessed our oil and gas properties for impairment as at December 31, 2012, and found no impairment write-down was required based on our calculations for any cost center. At March 31, 2012, we recorded a ceiling test impairment loss of \$20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. We assessed our oil and gas properties for impairment as at December 31, 2011, and found no impairment write-down was required based on our calculations for our Colombia and Brazil cost centers. As a result of assessing oil and gas properties in our Peru and Argentina cost centers, ceiling test impairment losses of \$42.0 million and \$25.7 million respectively were recorded. The 2011 impairment charge in the Peru cost center related to seismic and drilling costs from dry wells on two blocks which were relinquished. The 2011 impairment charge in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. We assessed our oil and gas properties for impairment as at December 31, 2010, and found no impairment write-down was required based on our assumptions for our Colombia cost center. A ceiling test impairment loss of \$23.6 million was recorded in our Argentina cost center in 2010 as a result of the abandonment of the GTE.St.VMor-2001 sidetrack operations, an increase in estimated future operating costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes.

Because of the volatile nature of oil and gas prices, it is not possible to predict the timing or magnitude of full cost writedowns. In addition, due to the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates. However, decreases in estimates of proved reserves would generally increase our depletion rate and, thus, our depletion expense. Decreases in our proved reserves may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test previously discussed. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expenses.

Unproved properties

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. Unproved properties, the costs of which are individually significant, are assessed individually by considering seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, these properties are grouped for purposes of assessing impairment. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to amortization. The transfer of costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, G&G evaluations, the assignment of proved reserves, availability of capital, and other factors. For countries where a reserve base has not yet been established, the impairment is charged to earnings.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future ARO requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record ARO in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities. In arriving at amounts recorded, we make numerous assumptions and judgments with respect to the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements, inflation factors, credit-adjusted risk-free discount rates and changes in legal, regulatory, environmental and political environments. Because costs typically extend many years into the future, estimating future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results.

Allocation of Consideration Transferred in Business Combinations

The acquisition of properties in Brazil in 2012 was accounted for using the acquisition method whereby the assets acquired and liabilities assumed were recorded at their fair values at the acquisition date. The fair value of the consideration transferred was equal to the fair value of the net assets acquired and no gain or goodwill was recorded on acquisition.

The acquisition of Petrolifera in 2011 was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby the Petrolifera assets acquired and liabilities assumed were recorded at their fair values at the acquisition date with the excess of the fair values of the net assets acquired over the consideration transferred recorded as a gain on acquisition. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, was subject to estimates which include various assumptions including the fair value of proved and unproved reserves of the acquired company as well as the future production and development costs and future oil and gas prices.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both oil and gas properties and non-oil and gas properties, the lower future net income will be as a result of higher future DD&A expenses. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling write down in the event that future oil and gas prices drop below the price forecast used to originally determine fair value.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed. The goodwill on our balance sheet resulted from the Solana and Argosy Energy International L.P. acquisitions, in 2008 and 2006 respectively, and relates entirely to the Colombia reporting unit. At each reporting date, we assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. Changes in our future cash flows, operating results, growth rates, capital expenditures, cost of capital, discount rates, stock price or related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

The two-step goodwill impairment test would require a comparison of the fair value of each reporting unit to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, we would write down the goodwill to the implied fair value of the goodwill through a charge to expense. The most significant judgments involved in estimating the fair values of our reporting units would relate to the valuation of our property and equipment. A lower goodwill value decreases the likelihood of an impairment charge. However, unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

Income Taxes

We follow the liability method of accounting for income taxes whereby we recognize deferred income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have made adequate provision for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment.

Our effective tax rate is based on pre-tax income and the tax rates applicable to that income in the various jurisdictions in which we operate. An estimated effective tax rate for the year is applied to our quarterly operating results. In the event that there is a significant unusual or discrete item recognized, or expected to be recognized, in our quarterly operating results, the tax attributable to that item would be separately calculated and recorded at the same time as the unusual or discrete item. We consider the resolution of prior-year tax matters to be such items. Significant judgment is required in determining our effective tax rate and in evaluating our tax positions. We establish reserves when it is more likely than not that we will not realize the full tax benefit of the position. We adjust these reserves in light of changing facts and circumstances.

We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts.

Legal and Other Contingencies

A provision for legal and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. Management closely monitors known and potential legal and other contingencies and periodically determines when we should record losses for these items based on information available to us.

Stock-Based Compensation

Our stock-based compensation cost is measured based on the fair value of the award on the grant date. The compensation cost is recognized net of estimated forfeitures over the requisite service period. GAAP requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

We utilize the Black-Scholes option pricing model to measure the fair value of all of our stock options. The use of such models requires substantial judgment with respect to expected life, volatility, expected returns and other factors. Expected volatility is based on the historical volatility of our shares. We use historical experience for exercises to determine expected life. We are responsible for determining the assumptions used in estimating the fair value of our share based payment awards.

New Accounting Pronouncements

We have reviewed all recently issued, but not yet adopted, accounting standard updates in order to determine their effects, if any, on our consolidated financial statements. Based on that review, we believe that the implementation of these standards will not materially impact our consolidated financial position, operating results, cash flows, or disclosure requirements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our principal market risk relates to oil prices. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to WTI or Brent and adjusted for quality each month. In Argentina, a further discount factor which is related to a tax on oil exports establishes a common pricing mechanism for all oil produced in the country, regardless of its destination.

Foreign currency risk is a factor for our company but is ameliorated to a large degree by the nature of expenditures and revenues in the countries where we operate. We have not engaged in any formal hedging activity with regard to foreign currency risk. Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil.

In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars. In Argentina and Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of our capital expenditures within Argentina and Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. The majority of our capital expenditures in Peru are in U.S. dollars. The majority of income and value added taxes and G&A expenses in all locations are in local currency. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. For the year ended December 31, 2012, our realized foreign exchange loss was \$14.3 million (2011 - \$2.2 million). A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at \$105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

We consider our exposure to interest rate risk to be immaterial. Our interest rate exposures primarily relate to our investment portfolio. Our investment objectives are focused on preservation of principal and liquidity. By policy, we manage our exposure to market risks by limiting investments to high quality bank issues at overnight rates, or U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. A 10% change in interest rates would not have a material effect on the value of our investment portfolio. We do not hold any of these investments for trading purposes. We do not hold equity investments, and we have no debt.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Gran Tierra Energy Inc.:

We have audited the accompanying consolidated financial statements of Gran Tierra Energy Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of operations and retained earnings, consolidated statements of shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2012, and the notes to the financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and its subsidiaries as at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

Other Matters

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte LLP

Independent Registered Chartered Accountants

Calgary, Canada

February 26, 2013

Gran Tierra Energy Inc.
Consolidated Statements of Operations and Retained Earnings
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

	Year Ended December 31,		
	2012	2011	2010
REVENUE AND OTHER INCOME			
Oil and natural gas sales	\$ 583,109	\$ 596,191	\$ 373,286
Interest income	2,078	1,216	1,174
	<u>585,187</u>	<u>597,407</u>	<u>374,460</u>
EXPENSES			
Operating	124,903	86,497	59,446
Depletion, depreciation, accretion and impairment (Note 6)	182,037	231,235	163,573
General and administrative	58,882	60,389	40,241
Other gain (Note 9)	(9,336)	—	—
Equity tax (Note 9)	—	8,271	—
Financial instruments gain (Note 3)	—	(1,522)	(44)
Gain on acquisition (Note 3)	—	(21,699)	—
Foreign exchange loss (gain)	31,338	(11)	16,838
	<u>387,824</u>	<u>363,160</u>	<u>280,054</u>
INCOME BEFORE INCOME TAXES	197,363	234,247	94,406
Income tax expense (Note 9)	(97,704)	(107,330)	(57,234)
NET INCOME AND COMPREHENSIVE INCOME	99,659	126,917	37,172
RETAINED EARNINGS, BEGINNING OF YEAR	185,014	58,097	20,925
RETAINED EARNINGS, END OF YEAR	<u>\$ 284,673</u>	<u>\$ 185,014</u>	<u>\$ 58,097</u>
NET INCOME PER SHARE — BASIC	\$ 0.35	\$ 0.46	\$ 0.15
NET INCOME PER SHARE — DILUTED	\$ 0.35	\$ 0.45	\$ 0.14
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 7)	280,741,255	273,491,564	253,697,076
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 7)	284,172,254	281,287,002	264,304,831

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Consolidated Balance Sheets
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

	As at December 31, 2012	
	2012	2011
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 212,624	\$ 351,685
Restricted cash	1,404	1,655
Accounts receivable (Note 5)	119,844	69,362
Inventory (Note 5)	33,468	7,116
Taxes receivable	39,922	21,485
Prepays	4,074	3,597
Deferred tax assets (Note 9)	2,517	3,029
Total Current Assets	413,853	457,929
Oil and Gas Properties (using the full cost method of accounting)		
Proved	813,247	618,982
Unproved	383,414	417,868
Total Oil and Gas Properties	1,196,661	1,036,850
Other capital assets	8,765	7,992
Total Property, Plant and Equipment (Note 6)	1,205,426	1,044,842
Other Long-Term Assets		
Restricted cash	1,619	13,227
Deferred tax assets (Note 9)	1,401	4,747
Taxes receivable	1,374	—
Other long-term assets	6,621	3,454
Goodwill	102,581	102,581
Total Other Long-Term Assets	113,596	124,009
Total Assets	\$ 1,732,875	\$ 1,626,780
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable (Note 10)	\$ 102,263	\$ 82,189
Accrued liabilities (Note 10)	66,418	66,832
Taxes payable	22,339	95,482
Deferred tax liabilities (Note 9)	337	—
Asset retirement obligation (Note 8)	28	326
Total Current Liabilities	191,385	244,829
Long-Term Liabilities		
Deferred tax liabilities (Note 9)	225,195	186,799
Equity tax payable (Note 9)	3,562	6,484
Asset retirement obligation (Note 8)	18,264	12,343
Other long-term liabilities	3,038	2,007
Total Long-Term Liabilities	250,059	207,633
Commitments and Contingencies (Note 11)		
Shareholders' Equity		
Common stock (Note 7) (268,482,445 and 262,304,249 shares of Common Stock and 13,421,488 and 16,323,819 exchangeable shares, par value \$0.001 per share, issued and outstanding as at December 31, 2012, and December 31, 2011, respectively)	7,986	7,510
Additional paid in capital	998,772	980,014
Warrants (Note 7)	—	1,780
Retained earnings	284,673	185,014
Total Shareholders' Equity	1,291,431	1,174,318
Total Liabilities and Shareholders' Equity	\$ 1,732,875	\$ 1,626,780

Gran Tierra Energy Inc.
Consolidated Statements of Cash Flows
(Thousands of U.S. Dollars)

	Year Ended December 31,		
	2012	2011	2010
Operating Activities			
Net income	\$ 99,659	\$ 126,917	\$ 37,172
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, accretion and impairment	182,037	231,235	163,573
Deferred tax expense (recovery) (Note 9)	26,274	(28,685)	(19,679)
Stock-based compensation (Note 7)	12,006	12,767	8,025
Unrealized gain on financial instruments (Note 3)	—	(1,354)	(44)
Unrealized foreign exchange loss (gain)	17,054	(2,232)	14,375
Settlement of asset retirement obligation (Note 8)	(404)	(345)	(286)
Other gain (Note 9)	(9,336)	—	—
Equity tax	(3,534)	2,442	—
Gain on acquisition (Note 3)	—	(21,699)	—
Net change in assets and liabilities from operating activities			
Accounts receivable and other long-term assets	(56,669)	(15,627)	(5,323)
Inventory	(18,195)	(548)	(1,221)
Prepays	(477)	(1,321)	(120)
Accounts payable and accrued and other liabilities	(8,387)	16,780	(3,176)
Taxes receivable and payable	(83,709)	35,422	10,522
Net cash provided by operating activities	<u>156,319</u>	<u>353,752</u>	<u>203,818</u>
Investing Activities			
Decrease (increase) in restricted cash	11,859	(10,197)	352
Additions to property, plant and equipment	(276,084)	(333,194)	(152,299)
Proceeds from disposition of oil and gas properties (Note 6)	—	4,450	7,986
Cash paid for acquisition (Note 3)	(35,495)	—	—
Cash acquired on acquisition (Note 3)	—	7,747	—
Proceeds on sale of asset-backed commercial paper (Note 3)	—	22,679	—
Net cash used in investing activities	<u>(299,720)</u>	<u>(308,515)</u>	<u>(143,961)</u>
Financing Activities			
Settlement of bank debt (Note 3)	—	(54,103)	—
Proceeds from issuance of shares of Common Stock	4,340	5,123	24,785
Net cash provided by (used in) financing activities	<u>4,340</u>	<u>(48,980)</u>	<u>24,785</u>
Net (decrease) increase in cash and cash equivalents	(139,061)	(3,743)	84,642
Cash and cash equivalents, beginning of year	351,685	355,428	270,786
Cash and cash equivalents, end of year	<u>\$ 212,624</u>	<u>\$ 351,685</u>	<u>\$ 355,428</u>
Cash	\$ 207,392	\$ 172,645	\$ 272,151
Term deposits	5,232	179,040	83,277
Cash and cash equivalents, end of year	<u>\$ 212,624</u>	<u>\$ 351,685</u>	<u>\$ 355,428</u>
Supplemental cash flow disclosures:			
Cash paid for interest	\$ —	\$ 1,604	\$ —
Cash paid for income taxes	\$ 143,498	\$ 67,053	\$ 49,088
Non-cash investing activities:			
Non-cash net assets and liabilities related to property, plant and equipment, end of year	<u>\$ 75,393</u>	<u>\$ 43,333</u>	<u>\$ 48,640</u>

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Consolidated Statements of Shareholders' Equity
(Thousands of U.S. Dollars)

	Year Ended December 31,		
	2012	2011	2010
Share Capital			
Balance, beginning of year	\$ 7,510	\$ 4,797	\$ 1,431
Issue of shares of Common Stock	476	2,713	3,366
Balance, end of year	<u>7,986</u>	<u>7,510</u>	<u>4,797</u>
Additional Paid in Capital			
Balance, beginning of year	980,014	821,781	766,963
Issue of shares of Common Stock	2,902	142,109	19,119
Exercise of warrants (Note 7)	1,590	411	24,916
Expiry of warrants (Note 7)	190	—	—
Exercise of stock options (Note 7)	960	1,990	2,300
Stock-based compensation (Note 7)	13,116	13,723	8,483
Balance, end of year	<u>998,772</u>	<u>980,014</u>	<u>821,781</u>
Warrants			
Balance, beginning of year	1,780	2,191	27,107
Exercise of warrants (Note 7)	(1,590)	(411)	(24,916)
Expiry of warrants (Note 7)	(190)	—	—
Balance, end of year	<u>—</u>	<u>1,780</u>	<u>2,191</u>
Retained Earnings			
Balance, beginning of year	185,014	58,097	20,925
Net income	99,659	126,917	37,172
Balance, end of year	<u>284,673</u>	<u>185,014</u>	<u>58,097</u>
Total Shareholders' Equity	<u>\$ 1,291,431</u>	<u>\$ 1,174,318</u>	<u>\$ 886,866</u>

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2012, 2011 and 2010
(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

Gran Tierra Energy Inc., a Nevada corporation (the “Company” or “Gran Tierra”), is a publicly traded oil and gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties. The Company’s principal business activities are in Colombia, Argentina, Peru and Brazil.

2. Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”). The Company believes that the information and disclosures presented are adequate to ensure the information presented is not misleading.

Significant accounting policies are:

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows; depreciation, depletion, amortization and impairment (“DD&A”); impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to amortization to the amortization base; asset retirement obligations; determining the value of the consideration transferred and the net identifiable assets acquired and liabilities assumed in connection with business combinations and determining goodwill; income taxes; legal and other contingencies; and stock-based compensation. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates.

Cash and cash equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted cash

Restricted cash comprises cash and cash equivalents pledged to secure letters of credit and to settle asset retirement obligations. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. Cash and claims to cash that are restricted as to withdrawal or use for other than current operations or are designated for expenditure in the acquisition or construction of long-term assets are excluded from the current asset classification.

Allowance for doubtful accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred. The allowance for doubtful receivables was nil at December 31, 2012, and 2011.

Inventory

Inventory consists of oil in tanks and third party pipelines, and supplies and is valued at the lower of cost or market value. The cost of inventory is determined using the weighted average method. Oil inventories include expenditures incurred to produce, upgrade and transport the product to the storage facilities and include operating, depletion and depreciation expenses and cash royalties.

Income taxes

Income taxes are recognized using the liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the consolidated financial statement carrying amounts of existing assets and liabilities and their respective tax base, and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. Valuation allowances are provided if, after considering available evidence, it is not more likely than not that some or all of the deferred tax assets will be realized.

The tax benefit from an uncertain tax position is recognized when it is more likely than not, based on the technical merits of the position, that the position will be sustained on examination by the taxing authorities. Additionally, the amount of the tax benefit recognized is the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the Company presumes that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The Company recognizes potential penalties and interest related to unrecognized tax benefits as a component of income tax expense.

Oil and gas properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as defined by the Securities and Exchange Commission ("SEC"). Under this method, the Company capitalizes all acquisition, exploration and development costs incurred for the purpose of finding oil and natural gas reserves, including salaries, benefits and other internal costs directly attributable to these activities. Costs associated with production and general corporate activities; however, are expensed as incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and natural gas properties. Separate cost centers are maintained for each country in which the Company incurs costs.

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion. The costs of unproved properties are excluded from the amortization until the properties are evaluated. The cost of exploratory dry wells is transferred to proved properties, and thus is subject to amortization, immediately upon determination that a well is dry in those countries where proved reserves exist.

The Company performs a ceiling test calculation each quarter in accordance with SEC Regulation S-X Rule 4-10. In performing its quarterly ceiling test, the Company limits, on a country-by-country basis, the capitalized costs of proved oil and natural gas properties, net of accumulated depletion and deferred income taxes, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the costs being amortized. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to net income. Any such write-down will reduce earnings in the period of occurrence and results in a lower DD&A rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company calculates future net cash flows by applying the unweighted average of prices in effect on the first day of the month for the preceding 12 month period, adjusted for location and quality differentials. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts.

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. This evaluation considers, among other factors, seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to amortization. For countries where a reserve base has not yet been established, the impairment is charged to earnings.

In exploration areas, related geological and geophysical ("G&G") costs are capitalized in unproved property and evaluated as part of the total capitalized costs associated with a property. G&G costs related to development projects are recorded in proved properties and therefore subject to amortization as incurred.

Gains and losses on the sale or other disposition of oil and natural gas properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

Asset retirement obligation

The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to the related oil and gas properties. The fair value of asset retirement obligations are measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value, while the asset retirement cost is amortized over the estimated productive life of the related assets. The accretion of the asset retirement obligation and amortization of the asset retirement cost are included in DD&A. If estimated future costs of asset retirement obligations change, an adjustment is recorded to both the asset retirement obligation and oil and gas properties. Revisions to the estimated asset retirement obligation can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Other capital assets

Other capital assets, including additions and replacements, are recorded at cost upon acquisition and include furniture, fixtures and leasehold improvement, computer equipment and automobiles. Depreciation is provided using the declining-balance method at a 30% annual rate for furniture and fixtures, computer equipment and automobiles. Leasehold improvements are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expense as incurred.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed. The Company assesses qualitative factors annually, or more frequently if necessary, to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. The impairment test requires allocating goodwill and certain other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared with the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for the Company's reporting units, the fair values of the reporting units are estimated based upon estimated future cash flows of the reporting unit.

The Company recorded \$87.6 million of goodwill in relation to the acquisition of Solana Resources Limited ("Solana") in 2008 and \$15.0 million of goodwill in relation to the Argosy Energy International L.P. ("Argosy") acquisition in 2006. The goodwill relates entirely to the Colombia reportable segment. The Company performed a qualitative assessment of goodwill at December 31, 2012, and based on this assessment, no impairment of goodwill was identified.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable, the sale is evidenced by a contract and collection of the revenue is reasonably assured. On February 1, 2012, the sales point for the majority of the Company's Colombian oil sales in the Putumayo Basin changed. Gran Tierra's primary customer, Ecopetrol S.A. ("Ecopetrol"), now takes title at the Port of Tumaco on the Pacific coast of Colombia rather than at the entry into the Ecopetrol-operated Trans-Andean oil pipeline ("the OTA pipeline") at the Orito Station in the Putumayo Basin. In Colombia, the Company has other sales contracts where the sales point is the purchaser's facilities or when oil is loaded into a truck at Gran Tierra's loading facility or an export tanker. In Argentina, Gran Tierra transports oil from the field to the customer's refinery or the oil terminal by pipeline or truck, where title is transferred. For the Company's gas sales in Argentina, Gran Tierra's customers take title when the gas is transferred to their pipeline. In Brazil, Gran Tierra transports product from the field to the customer's station by truck, where title is transferred. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company follows the fair-value based method of accounting for stock options granted to directors, officers and employees. Compensation expense for options granted is based on the estimated fair value, using the Black-Scholes option pricing model, at the time of grant and the expense, net of estimated forfeitures, is recognized over the requisite service period using the accelerated method. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures related to vested awards. The Company uses historical data to estimate option exercises, expected term and employee departure behavior used in the Black-Scholes option pricing model. Expected volatilities used in the fair value estimate are based on historical volatility of the Company's shares. The risk-free rate for periods within the expected term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant. Stock-based compensation expense is capitalized as part of oil and natural gas properties or expensed as part of operating expenses or general and administrative ("G&A") expenses, as appropriate.

Warrants

The Company issued warrants ("Replacement Warrants") in connection with its acquisition of Petrolifera Petroleum Limited ("Petrolifera") in March 2011 (Note 3). The Replacement Warrants expired unexercised during August 2011. These warrants were derivative financial instruments and were recognized at fair value in the consolidated balance sheet as a current liability and as part of the consideration paid for the acquisition. The Company determined the fair value of warrants issued using the Black-Scholes option pricing model.

Foreign currency translation

The functional currency of the Company, including its subsidiaries, is the United States dollar. Monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date and non-monetary items are translated at historical exchange rates. Revenue and expense items are translated in a manner that produces substantially the same reporting currency amounts that would have resulted had the underlying transactions been translated on the dates they occurred. Depreciation or amortization of assets is translated at the historical exchange rates similar to the assets to which they relate.

Gains and losses resulting from foreign currency transactions, which are transactions denominated in a currency other than the entity's functional currency, are recognized in net income.

Net income per share

Basic net income per share is calculated by dividing net income attributable to common shareholders by the weighted average number of shares of Common Stock and exchangeable shares issued and outstanding during each period. Diluted net income per share is calculated by adjusting the weighted average number of shares of Common Stock and exchangeable shares outstanding for the dilutive effect, if any, of share equivalents. The Company uses the treasury stock method to determine the dilutive effect. This method assumes that all Common Stock equivalents have been exercised at the beginning of the period (or at the time of issuance, if later), and that the funds obtained thereby were used to purchase shares of Common Stock of the Company at the volume weighted average trading price of shares of Common Stock during the period.

Adopted Accounting Pronouncements

Goodwill

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-08, "Intangibles – Goodwill and Other (Topic 350)." The update is intended to simplify how entities test goodwill for impairment. The update permits entities to assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. This ASU was effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2011. The implementation of this update did not materially impact the Company's consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

Disclosure about Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU 2011-11, "Balance Sheet – Disclosure about Offsetting Assets and Liabilities (Topic 210)." The update requires an entity to disclose information about offsetting assets and liabilities and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. This ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after January 1, 2013. The implementation of this update is not expected to materially impact the Company's disclosure.

3. Business Combination

Brazil

On October 8, 2012, the Company received regulatory approval and acquired the remaining 30% working interest in four blocks in Brazil pursuant to the terms of a purchase and sale agreement dated January 20, 2012. With the exception of one block which has three producing wells, the remaining blocks are unproved properties.

The Company paid initial cash purchase consideration of \$28.0 million and an interim period purchase price adjustment of \$7.5 million, representing the 30% share of all benefits and costs with respect to the period between the effective date and the completion of the transaction. Contingent consideration up to an additional \$3.0 million may be payable dependent on production volumes from the acquired blocks.

The acquisition was accounted for as a business combination using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recognized at their fair values as at October 8, 2012, the acquisition date, and the results of the blocks were included with those of Gran Tierra from that date. Fair value estimates were made based on significant unobservable (Level 3) inputs and based on the best information available at the time.

Contingent consideration was recorded on the balance sheet at the acquisition date fair value based on the consideration expected to be transferred, discounted back to present value by applying an appropriate discount rate that reflected the risk factors associated with the payment streams. The discount rate used was determined at the time of measurement in accordance with accepted valuation methods. The acquisition date fair value of the contingent consideration was \$1.1 million and was recorded in other long-term liabilities. The fair value of the contingent consideration is being remeasured at the estimated fair value at each reporting period with the change in fair value recognized as income or expense in operating income. Any changes in fair value will impact earnings in such reporting period until the contingencies are resolved. There was no significant change in the fair value of the contingent consideration between October 8, 2012, and December 31, 2012.

The following table shows the allocation of the consideration transferred based on the fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)

Consideration Transferred:

Cash	\$	35,495
Fair value of contingent consideration payable		1,061
	\$	<u>36,556</u>

Allocation of Consideration Transferred (1):

Oil and gas properties		
Proved	\$	24,107
Unproved		12,859
Asset retirement obligation		(410)
	\$	<u>36,556</u>

(1) The allocation of the consideration transferred is not final and is subject to change.

Pro forma results (unaudited)

Pro forma results related to this acquisition have not been disclosed because oil and natural gas sales and net income related to the 30% working interest for the years ended December 31, 2012, and 2011 were not material in relation to the Company's consolidated financial statements. Production from these blocks was not significant during these periods.

Petrolifera Petroleum Limited

On March 18, 2011 (the "Acquisition Date"), Gran Tierra completed its acquisition of all the issued and outstanding common shares and warrants of Petrolifera, a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011 (the "Arrangement"). Petrolifera is a Calgary based oil, natural gas and natural gas liquids exploration, development and production company active in Argentina, Colombia and Peru. The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petrolifera shareholders on March 17, 2011, and by the Court of Queen's Bench of Alberta on March 18, 2011.

Under the Arrangement, Petrolifera shareholders received, for each Petrolifera share held, 0.1241 of a share of Gran Tierra Common Stock, and Petrolifera warrant holders received, for each Petrolifera warrant held, 0.1241 of a warrant (a "Replacement Warrant") to purchase a share of Gran Tierra Common Stock at an exercise price of \$9.67 Canadian ("CDN") dollars per share. The Replacement Warrants expired unexercised on August 28, 2011.

Gran Tierra acquired all the issued and outstanding Petrolifera shares and warrants through the issuance of 18,075,247 shares of Gran Tierra Common Stock, par value \$0.001, and 4,125,036 Replacement Warrants. Upon completion of the transaction on the Acquisition Date, Petrolifera became an indirect wholly-owned subsidiary of Gran Tierra. On a diluted basis, upon the closing of the Arrangement, Petrolifera and Gran Tierra security holders owned approximately 6.6% and 93.4% of the Company, respectively, immediately following the transaction. The total consideration for the transaction was approximately \$143.0 million.

The fair value of Gran Tierra's Common Stock was determined as the closing price of shares of the Common Stock of Gran Tierra as at the Acquisition Date.

The fair value of the Replacement Warrants was estimated on the Acquisition Date using the Black-Scholes option pricing model with the following assumptions:

Exercise price (CDN dollars per warrant)	\$	9.67
Risk-free interest rate		1.3%
Expected life		0.45 years
Volatility		44%
Expected annual dividend per share		Nil
Estimated fair value per warrant (CDN dollars)	\$	0.32

The Replacement Warrants met the definition of a derivative and, due to the fact that the exercise price of the Replacement Warrants was denominated in Canadian dollars, which is different from Gran Tierra's functional currency, the Replacement Warrants were not considered indexed to Gran Tierra's shares of Common Stock and the Replacement Warrants could not be classified within equity. Therefore, the Replacement Warrants were classified as a current liability on Gran Tierra's consolidated balance sheet. Furthermore, these derivative instruments did not qualify as fair value hedges or cash flow hedges, and accordingly, changes in their fair value were recognized as income or expense in the consolidated statement of operations with a corresponding adjustment to the fair value of derivative instruments recognized on the balance sheet. The financial instruments gain for the year ended December 31, 2011, included a \$1.3 million gain arising from the fair value of the expired Replacement Warrants.

The acquisition was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera's assets acquired and liabilities assumed are recognized at their fair values as at the Acquisition Date and the results of Petrolifera have been consolidated with those of Gran Tierra from that date.

The following table shows the allocation of the consideration transferred based on the fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)

Consideration Transferred:

Shares of Common Stock issued net of share issue costs	\$ 141,690
Replacement warrants	1,354
	<u>\$ 143,044</u>

Allocation of Consideration Transferred:

Oil and gas properties	
Proved	\$ 58,457
Unproved	161,278
Other long-term assets	4,417
Net working capital (including cash acquired of \$7.7 million and accounts receivable of \$6.4 million)	(17,223)
Asset retirement obligation	(4,901)
Bank debt	(22,853)
Other long-term liabilities	(14,432)
Gain on acquisition	(21,699)
	<u>\$ 143,044</u>

As shown above, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized a gain of \$21.7 million, which was reported as “Gain on acquisition” in the consolidated statement of operations. The gain reflected the impact on Petrolifera’s pre-acquisition market value of a lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

As part of the assets acquired and included in the net working capital in the allocation of the consideration transferred, the Company assigned \$22.5 million in fair value to investments in notes that Petrolifera received in exchange for asset-backed commercial paper (“ABCP”) with a face value of \$31.3 million. On March 28, 2011, these notes were sold to an unrelated party for proceeds of \$22.7 million after the associated line of credit was settled. When combined with the gain arising on expiry of the Replacement Warrants, the financial instruments gain for the year ended December 31, 2011, was \$1.5 million.

The associated ABCP line of credit that Gran Tierra assumed was with a Canadian chartered bank, to a maximum of CDN \$23.2 million with an initial expiry in April 2012. Gran Tierra settled this line of credit immediately after the completion of the acquisition of Petrolifera for the face value of CDN \$22.5 million in borrowings plus accrued interest.

Also upon the acquisition of Petrolifera, Gran Tierra assumed a second line of credit agreement (“Second ABCP line of credit”) with the same Canadian chartered bank to a maximum of CDN \$5.0 million, which was fully drawn as at the Acquisition Date. This Second ABCP line of credit, which expired on April 8, 2011, was secured by ineligible master asset vehicles Classes 1 & 2 (“MAV IA 1 & 2”) notes with a face value of \$6.6 million. Gran Tierra retained the option to settle the Second ABCP line of credit of CDN \$5.0 million through delivery to the lender of the MAV IA 1 & 2 notes. Subsequent to the acquisition, Gran Tierra elected to record this second line of credit at fair value and planned at that time to settle the debt through delivery of the MAV IA 1 & 2 notes. Accordingly, a value of \$nil was recorded for the debt upon its acquisition. Gran Tierra settled such borrowings by delivery of the MAV IA 1 & 2 notes on April 8, 2011.

Gran Tierra also assumed a reserve-backed credit facility upon the Petrolifera acquisition with an outstanding balance of \$31.3 million. The amount outstanding under this credit facility was included as part of net working capital in the allocation of consideration transferred. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries. The outstanding balance was repaid when the Argentina restriction preventing its repayment expired on August 5, 2011, resulting in a total debt repayment of \$54.1 million, when combined with the repayment of the CDNS\$22.5 million ABCP line of credit. Interest expense on the credit facility for the 140-day period from the Acquisition Date to August 5, 2011, was \$1.6 million. This amount is recorded in the consolidated statements of operations as part of G&A expenses in the Argentina segment.

Pro forma results (unaudited)

Pro forma results for the year ended December 31, 2011, are shown below, as if the acquisition had occurred on January 1, 2010. Pro forma results are not indicative of actual results or future performance.

(Unaudited, thousands of U.S. Dollars, except per share amounts)	Year Ended December 31,	
	2011	
Revenue and other income	\$	606,602
Net income	\$	94,094
Net income per share - basic	\$	0.34
Net income per share - diluted	\$	0.33

The supplemental pro forma earnings of Gran Tierra for the year ended December 31, 2011, were adjusted to exclude \$4.4 million of acquisition costs recorded in G&A expenses and the \$21.7 million gain on acquisition because they were not expected to have a continuing impact on Gran Tierra's results of operations. The consolidated statement of operations for the year ended December 31, 2011, included revenue of \$32.5 million from Petrolifera for the period subsequent to the Acquisition Date. Petrolifera incurred a loss after tax of \$8.0 million in the period from the Acquisition Date to December 31, 2011.

4. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company's reportable segments are Colombia, Argentina, Peru and Brazil based on geographic organization. The level of activity in Brazil was not significant at December 31, 2012, 2011 or 2010; however, the Company has separately disclosed its results of operations in Brazil as a reportable segment. The All Other category represents the Company's corporate activities.

The accounting policies of the reportable segments are the same as those described in Note 2. The Company evaluates reportable segment performance based on income or loss before income taxes. The segmented results include the operations of Petrolifera subsequent to March 18, 2011, the Acquisition Date (Note 3).

The following tables present information on the Company's reportable segments and other activities:

Year Ended December 31, 2012

(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$ 493,615	\$ 79,642	\$ —	\$ 9,852	\$ —	\$ 583,109
Interest income	667	355	49	607	400	2,078
DD&A expenses	122,055	31,466	1,234	26,300	982	182,037
DD&A - per unit of production	25.37	24.74	—	259.88	—	29.44
Income (loss) before income taxes	244,474	1,060	(5,493)	(24,543)	(18,135)	197,363
Segment capital expenditures (1)	\$ 153,331	\$ 40,653	\$ 62,869	\$ 55,239	\$ 1,084	\$ 313,176

Year Ended December 31, 2011

(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$ 543,999	\$ 48,016	\$ —	\$ 4,176	\$ —	\$ 596,191
Interest income	492	66	140	84	434	1,216
DD&A expenses	141,133	45,506	42,035	1,819	742	231,235
DD&A - per unit of production	26.17	49.61	—	42.25	—	36.39
Income (loss) before income taxes	313,516	(32,635)	(46,249)	(3,878)	3,493	234,247
Segment capital expenditures (2)	\$ 202,551	\$ 36,289	\$ 36,224	\$ 50,836	\$ 1,747	\$ 327,647

Year Ended December 31, 2010

(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$ 359,302	\$ 13,984	\$ —	\$ —	\$ —	\$ 373,286
Interest income	460	26	—	77	611	1,174
DD&A expenses	133,728	29,416	40	77	312	163,573
DD&A - per unit of production	26.80	103.56	—	—	—	31.02
Income (loss) before income taxes	142,486	(27,247)	(1,430)	(2,198)	(17,205)	94,406
Segment capital expenditures (2)	105,482	\$ 33,930	\$ 23,195	\$ 12,911	\$ 1,521	\$ 177,039

(1) In 2012, the Company also paid \$35.5 million to acquire the remaining 30% working interest in four blocks in Brazil (Note 3).

(2) In 2011, amounts are net of proceeds from the farm-out of a 50% working interest in the Santa Victoria Block and the sale of a blow-out preventer, both in Argentina (Note 6). In 2011, the Company also completed its acquisition of all the issued and outstanding common shares and warrants of Petrolifera (Note 3). In 2010, amounts are net of proceeds from the sale of the Garibay overriding royalty right in Colombia (Note 6) .

The Company's revenues are derived principally from uncollateralized sales to customers in the oil and natural gas industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions.

The Company has one significant customer in Colombia, Ecopetrol. Sales to Ecopetrol accounted for 74%, 87% and 96% of the Company's consolidated revenues for the years ended December 31, 2012, 2011 and 2010, respectively.

As at December 31, 2012

(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	All Other	Total
Property, plant and equipment	\$ 840,027	\$ 138,768	\$ 95,940	\$ 127,394	\$ 3,297	\$ 1,205,426
Goodwill	102,581	—	—	—	—	102,581
Other assets	222,220	47,038	10,880	8,498	136,232	424,868
Total Assets	\$ 1,164,828	\$ 185,806	\$ 106,820	\$ 135,892	\$ 139,529	\$ 1,732,875

As at December 31, 2011

(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	All Other	Total
Property, plant and equipment	\$ 816,396	\$ 129,072	\$ 34,305	\$ 61,875	\$ 3,194	\$ 1,044,842
Goodwill	102,581	—	—	—	—	102,581
Other assets	269,843	34,672	9,597	17,065	148,180	479,357
Total Assets	\$ 1,188,820	\$ 163,744	\$ 43,902	\$ 78,940	\$ 151,374	\$ 1,626,780

5. Accounts Receivable and Inventory

Accounts Receivable

(Thousands of U.S. Dollars)	As at December 31,	
	2012	2011
Trade	\$ 116,434	\$ 66,204
Other	3,410	3,158
	119,844	69,362

Inventory

At December 31, 2012, oil and supplies inventories were \$31.2 million and \$2.3 million, respectively (December 31, 2011 - \$4.7 million and \$2.4 million, respectively).

6. Property, Plant and Equipment

Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at December 31, 2012			As at December 31, 2011		
	Cost	Accumulated depletion, depreciation and impairment	Net book value	Cost	Accumulated depletion, depreciation and impairment	Net book value
Oil and natural gas properties						
Proved	\$ 1,562,477	\$ (749,230)	\$ 813,247	\$ 1,181,503	\$ (562,521)	\$ 618,982
Unproved	383,414	—	383,414	417,868	—	417,868
	1,945,891	(749,230)	1,196,661	1,599,371	(562,521)	1,036,850
Furniture and fixtures and leasehold improvements	7,575	(5,093)	2,482	6,973	(4,002)	2,971
Computer equipment	10,971	(5,248)	5,723	8,443	(4,174)	4,269
Automobiles	1,376	(816)	560	1,295	(543)	752
Total Property, Plant and Equipment	\$ 1,965,813	\$ (760,387)	\$ 1,205,426	\$ 1,616,082	\$ (571,240)	\$ 1,044,842

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2012, was \$168.0 million (year ended December 31, 2011 - \$162.6 million; year ended December 31, 2010 - \$139.2 million). A portion of depletion and depreciation expense was recorded as inventory in each year.

On June 5, 2012, the Company received regulatory approval of a farm-in agreement on a block in Colombia. This approval triggered a payment of \$21.1 million related to drilling costs for a previously drilled oil exploration well, which was recorded as a capital expenditure in the second quarter of 2012.

Effective June 1, 2012, the Company entered into an agreement to acquire the remaining 40% working interest in a block in Peru. The block is an unproved property. Purchase consideration was \$5.4 million and was recorded as a capital expenditure in the second quarter of 2012. The agreement is subject to government approval.

On August 26, 2010, the Company entered into an agreement to acquire a 70% working interest in four blocks in Brazil. With the exception of one block which has three producing wells, the remaining blocks are unproved properties. The agreement was effective September 1, 2010, subject to regulatory approvals, and the transaction was completed on June 15, 2011. Purchase consideration was \$40.1 million and was recorded as capital expenditures in 2011 and 2010. On January 20, 2012, the Company entered into an agreement to acquire the remaining 30% working interest in these four blocks and, on October 8, 2012, received regulatory approval and acquired the remaining 30% working interest. The 30% working interest acquisition was accounted for as a business combination using the acquisition method (Note 3).

In September 2011, the Company announced two farm-out agreements with Statoil do Brasil Ltda. ("Statoil") in a joint venture with Petróleo Brasileiro S.A. pursuant to which, the Company would receive an assignment of a non-operated 10% working interest in Block BM-CAL-7 and a non-operated 15% working interest in Block BM-CAL-10. Both blocks are located in the Camamu Basin, offshore Bahia, Brazil.

During the first quarter of 2012, the Company received regulatory approval from Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") for the Block BM-CAL-7 farm-out agreement. Purchase consideration of \$0.7 million was paid and the assignment became effective on April 3, 2012. This block is an unproved property.

On February 17, 2012, in accordance with the terms of the farm-out agreement for Block BM-CAL-10, the Company gave notice to Statoil that it would not enter into and assume its share of the work obligations of the second exploration period of the block. As a result, the farm-out agreement terminated and the Company did not receive any interest in this block. Pursuant to the farm-out agreement, the Company was obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to a well that was drilled during the term of the farm-out agreement. The notice of withdrawal was a trigger for payment of amounts that would otherwise have been due if the farm-out agreement had closed and the Company had acquired a working interest. In the three months ended March 31, 2012, the Company recorded a ceiling test impairment loss in the Company's Brazil cost center of \$20.2 million. This impairment charge resulted from the recognition of \$23.8 million of capital expenditures in relation to the Block BM-CAL-10 farm-out agreement in the first quarter of 2012.

In the year ended December 31, 2011, the Company recorded a ceiling test impairment loss in the Company's Peru cost center of \$42.0 million. This impairment charge related to drilling costs from a dry well and seismic costs on blocks which were relinquished.

In the year ended December 31, 2011, the Company recorded a ceiling test impairment loss in the Company's Argentina cost center of \$25.7 million. This impairment charge related to an increase in estimated future operating and capital costs to produce the Company's remaining Argentina proved reserves and a decrease in reserve volumes.

In December 31, 2010, the Company recorded a \$23.6 million ceiling test impairment loss in the Company's Argentina cost center, of which \$17.9 million related to the abandonment of the Valle Morado sidetrack operations and the remaining \$5.7 million resulted from a decrease in reserves combined with higher forecasted operating costs to produce the remaining proved reserves.

In March 2011, the Company recorded proceeds of \$3.3 million from the farm-out of a 50% interest in the Santa Victoria Block in Argentina. The Company also recorded \$1.2 million from the sale of a blow-out preventer in Argentina in September 2011. In October 2010, the Company recorded proceeds of \$6.4 million for the sale of an overriding royalty right in the Garibay Block in Colombia. In April 2009, Gran Tierra closed the sale of the Company's interests in the Guachiria Norte, Guachiria, and Guachiria Sur blocks in Colombia. Consideration of \$7.0 million comprised an initial cash payment of \$4.0 million at closing, followed by 15 monthly installments of \$0.2 million each which began on June 1, 2009, and ended on August 3, 2010. The Company recorded proceeds of \$1.6 million and \$5.4 million in 2010 and 2009, respectively.

The amounts of G&A and stock-based compensation capitalized in each of the Company's cost centers during the years ended December 31, 2012, 2011 and 2010, respectively, were as follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2012				
	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	\$ 15,054	\$ 4,605	\$ 4,761	\$ 3,844	\$ 28,264
Capitalized stock-based compensation	\$ 481	\$ 354	\$ —	\$ 275	\$ 1,110

(Thousands of U.S. Dollars)	Year Ended December 31, 2011				
	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	\$ 7,996	\$ 3,189	\$ 1,183	\$ 1,985	\$ 14,353
Capitalized stock-based compensation	\$ 456	\$ 266	\$ —	\$ 234	\$ 956

(Thousands of U.S. Dollars)	Year Ended December 31, 2010				
	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	4,127	1,171	287	—	5,585
Capitalized stock-based compensation	308	150	—	—	458

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. As at December 31, 2012, the Company had \$175.9 million (December 31, 2011 - \$274.8 million) of unproved assets in Colombia, \$42.3 million (December 31, 2011 - \$57.0 million) of unproved assets in Argentina, \$95.1 million (December 31, 2011 - \$33.7 million) of unproved assets in Peru, and \$70.1 million (December 31, 2011 - \$52.4 million) of unproved assets in Brazil for a total of \$383.4 million (December 31, 2011 - \$417.9 million). These properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed. The Company expects that approximately 53% of costs not subject to depletion at December 31, 2012, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2012:

(Thousands of U.S. Dollars)	Costs Incurred in				
	2012	2011	2010	Prior to 2010	Total
Acquisition costs - Colombia	\$ —	\$ 8,647	\$ —	\$ 127,842	\$ 136,489
Acquisition costs - Argentina	—	35,051	—	—	35,051
Acquisition costs - Peru	5,400	23,423	2,000	—	30,823
Acquisition costs - Brazil	12,802	22,668	—	—	35,470
Exploration costs - Colombia	16,092	7,227	14,635	1,429	39,383
Exploration costs - Argentina	(588)	2,595	4,834	392	7,233
Exploration costs - Peru	58,286	6,019	—	—	64,305
Exploration costs - Brazil	17,128	17,532	—	—	34,660
Total oil and natural gas properties not subject to depletion	\$ 109,120	\$ 123,162	\$ 21,469	\$ 129,663	\$ 383,414

7. Share Capital

The Company's authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as Common Stock, par value \$0.001 per share, 25 million are designated as Preferred Stock, par value \$0.001 per share, and two shares are designated as special voting stock, par value \$0.001 per share.

As at December 31, 2012, outstanding share capital consists of 268,482,445 shares of Common Stock of the Company, 7,197,678 exchangeable shares of Gran Tierra Exchange Co., (the "Exchangeco exchangeable shares") that will be automatically exchangeable on November 14, 2013, except under certain specified circumstances, and 6,223,810 exchangeable shares of Goldstrike Exchange Co. (the "Goldstrike exchangeable shares"), automatically exchangeable on November 10, 2013. During the year ended December 31, 2012, 482,841 shares of Common Stock were issued upon the exercise of stock options, 2,793,024 shares of Common Stock were issued upon the exercise of warrants, 1,587,302 shares of Common Stock were issued upon the exchange of the Goldstrike exchangeable shares and 1,315,029 shares of common stock were issued upon the exchange of the Exchangeco exchangeable shares.

The holders of shares of Common Stock are entitled to one vote for each share on all matters submitted to a stockholder vote and are entitled to share in all dividends that the Company's board of directors, in its discretion, declares from legally available funds. The holders of Common Stock have no pre-emptive rights, no conversion rights, and there are no redemption provisions applicable to the shares.

The Exchangeco exchangeable shares were issued upon acquisition of Solana. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. On October 5, 2012, the automatic redemption date on the Goldstrike exchangeable shares was extended by one year to November 10, 2013. As at December 31, 2012, 95.8% of the Goldstrike exchangeable shares were held by directors and management of the Company. Holders of exchangeable shares have substantially the same rights as holders of shares of Common Stock. Each exchangeable share is exchangeable into one share of Common Stock of the Company.

Stock Options

As at December 31, 2012, the Company had a 2007 Equity Incentive Plan, formed through the approval by shareholders of the amendment and restatement of the 2005 Equity Incentive Plan, under which the Company's board of directors is authorized to issue options or other rights to acquire shares of the Company's Common Stock. On June 16, 2010, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 18,000,000 shares to 23,306,100 shares. On June 27, 2012, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares.

The Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. Each option permits the holder to purchase one share of Common Stock at the stated exercise price. At the time of grant, the exercise price equals the market price. The options vest over three years and have a term of ten years, or three months after the grantee's end of service to the Company, whichever occurs first. Currently, the Company's practice is to issue new shares upon stock option exercise. The Company does not expect to repurchase any shares in the open market to settle any such exercises.

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model based on assumptions noted in the following table:

	Year Ended December 31,		
	2012	2011	2010
Dividend yield (per share)	Nil	Nil	Nil
Volatility	59% to 75%	75% to 81%	84% to 90%
Weighted average volatility	75%	80%	89%
Risk-free interest rate	0.3% to 0.4%	0.4% to 1.4%	0.2% to 0.5%
Expected term	4-6 years	4-6 years	3 years

The following table provides information about stock option activity for the year ended December 31, 2012:

	Number of Outstanding Options	Weighted Average Exercise Price \$/Option
Balance, December 31, 2011	12,864,002	4.90
Granted	3,400,650	5.78
Exercised	(482,841)	(2.97)
Forfeited	(305,152)	(6.79)
Expired	(76,997)	(6.82)
Balance, December 31, 2012	15,399,662	5.11
Vested, or expected to vest, at December 31, 2012, through the life of the options	14,669,616	5.03

For the year ended December 31, 2012, 482,841 shares of Common Stock were issued upon the exercise of 482,841 stock options (2011 – 1,695,049; 2010 – 2,895,553). Cash proceeds from the exercise of stock options in the year ended December 31, 2012 were \$1.4 million.

At December 31, 2012, the weighted average remaining contractual term of outstanding stock options was 7.2 years and of exercisable stock options was 6.2 years.

The weighted average grant date fair value for options granted in the year ended December 31, 2012, was \$3.33 (2011 - \$4.84; 2010 - \$3.36). The weighted average grant date fair value for options vested in the year ended December 31, 2012, was \$3.90 (2011 - \$2.26; 2010 - \$1.61). The total fair value of stock options vested during year ended December 31, 2012, was \$10.2 million (2011 - \$6.6 million; 2010 - \$5.1 million).

For the year ended December 31, 2012, the stock-based compensation expense was \$13.1 million (2011- \$13.7 million; 2010 - \$8.5 million) of which \$10.9 million (2011 - \$11.4 million; 2010 - \$7.2 million) was recorded in G&A expenses, \$1.1 million was recorded in operating expenses (2011 – \$1.3 million; 2010 - \$0.8 million) and \$1.1 million was capitalized as part of exploration and development costs (2011 – \$1.0 million; 2010 - \$0.5 million).

At December 31, 2012, there was \$8.2 million (December 31, 2011 - \$11.7 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next three years.

The aggregate intrinsic value of options outstanding at December 31, 2012, was \$17.8 million (2011 - \$14.7 million; 2010 - \$49.9 million) based on the Company's closing share price of \$5.51 at December 31, 2012 (December 31, 2011 - \$4.80; December 31, 2010 - \$8.05). The aggregate intrinsic value of options exercisable at December 31, 2012, was \$17.6 million (December 31, 2011 - \$14.2 million; December 31, 2010 - \$49.4 million). The aggregate intrinsic value of options exercised in the year ended December 31, 2012, was \$1.4 million (2011 - \$6.2 million; 2010 - \$12.8 million). The aggregate intrinsic value of options vested, or expected to vest, at December 31, 2012, through the life of the options was \$17.8 million and the weighted-average remaining contractual term of these options was 7.2 years.

Warrants

At December 31, 2011, the Company had 6,298,230 warrants outstanding to purchase 3,149,115 shares of Common Stock for \$1.05 per share, expiring between June 20, 2012, and June 30, 2012. During the year ended December 31, 2012, 2,766,834 shares of Common Stock were issued upon the exercise of 5,550,668 warrants (2011 - 735,817 shares of Common Stock were issued upon the exercise of 1,471,634 warrants), 26,190 shares of Common Stock were issued with 7,143 shares withheld in lieu of a cashless exchange upon the exercise of 66,666 warrants, and 680,896 warrants expired unexercised.

Weighted Average Shares Outstanding

	Year Ended December 31,		
	2012	2011	2010
Weighted average number of common and exchangeable shares outstanding	280,741,255	273,491,564	253,697,076
Shares issuable pursuant to warrants	175,061	2,708,183	3,750,781
Shares issuable pursuant to stock options	5,879,929	5,143,498	7,402,966
Shares assumed to be purchased from proceeds of stock options	(2,623,991)	(56,243)	(545,992)
Weighted average number of diluted common and exchangeable shares outstanding	284,172,254	281,287,002	264,304,831

For the year ended December 31, 2012, 9,784,874 options (2011 - 3,726,999 options; 2010 - 290,000) were excluded from the diluted income per share calculation as the options were anti-dilutive.

8. Asset Retirement Obligation

Changes in the carrying amounts of the asset retirement obligation associated with the Company's oil and natural gas properties were as follows:

(Thousands of U.S. Dollars)	Year Ended December 31,	
	2012	2011
Balance, beginning of year	\$ 12,669	\$ 4,807
Settlements	(404)	(345)
Disposal	—	(172)
Liability incurred	5,190	867
Liability assumed in a business combination (Note 3)	410	4,901
Foreign exchange	45	17
Accretion	998	673
Revisions in estimated liability	(616)	1,921
Balance, end of year	\$ 18,292	\$ 12,669
Asset retirement obligation - current	\$ 28	\$ 326
Asset retirement obligation - long-term	18,264	12,343
Balance, end of year	\$ 18,292	\$ 12,669

Revisions to estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. At December 31, 2012, the fair value of assets that are legally restricted for purposes of settling asset retirement obligations was \$1.3 million (December 31, 2011 - \$0.8 million).

9. Taxes

The income tax expense reported differs from the amount computed by applying the U.S. statutory rate to income before income taxes for the following reasons:

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2012	2011	2010
Income (loss) before income taxes			
United States	(13,918)	4,984	(16,726)
Foreign	211,281	229,263	111,132
	197,363	234,247	94,406
	35%	35%	35%
Income tax expense expected	69,077	81,986	33,042
Foreign currency translation adjustments	5,473	(417)	6,409
Impact of foreign taxes	(1,833)	3,890	(3,094)
Stock-based compensation	3,982	4,013	2,381
Increase in valuation allowance	6,709	36,815	19,991
Branch and other foreign loss pick-up	(3,809)	(14,363)	(3,957)
Non-deductible third party royalty in Colombia	11,938	8,525	5,506
Enhanced tax depreciation incentive	—	—	(7,971)
Non-taxable gain on acquisition	—	(7,595)	—
Other permanent differences	6,167	(5,524)	4,927
Total income tax expense	\$ 97,704	\$ 107,330	\$ 57,234
Current income tax expense			
United States	1,233	1,029	501
Foreign	70,197	134,986	76,412
	71,430	136,015	76,913
Deferred income tax expense (recovery)			
United States	—	—	—
Foreign	26,274	(28,685)	(19,679)
	26,274	(28,685)	(19,679)
Total income tax expense	\$ 97,704	\$ 107,330	\$ 57,234

For the year ended December 31, 2012, other permanent differences in the rate reconciliation are tax effected at the 35% statutory rate. These differences include \$11.4 million of true-up provisions and loss adjustments, \$8.7 million of which are offset by a change in the valuation allowance and \$2.7 million of which are subject to local tax at a rate of 1.75%.

(Thousands of U.S. Dollars)	As at December 31,	
	2012	2011
Deferred Tax Assets		
Tax benefit of loss carryforwards	\$ 51,920	\$ 63,910
Tax basis in excess of book basis	22,519	17,065
Foreign tax credits and other accruals	30,926	27,164
Capital losses	4,779	2,433
Deferred tax assets before valuation allowance	110,144	110,572
Valuation allowance	(106,226)	(102,796)
	<u>\$ 3,918</u>	<u>\$ 7,776</u>
Deferred tax assets - current	\$ 2,517	\$ 3,029
Deferred tax assets - long-term	1,401	4,747
	<u>3,918</u>	<u>7,776</u>
Deferred tax liabilities - current	(337)	—
Deferred tax liabilities - long-term	(225,195)	(186,799)
	<u>\$ (225,532)</u>	<u>\$ (186,799)</u>
Net Deferred Tax Liabilities	<u>\$ (221,614)</u>	<u>\$ (179,023)</u>

Undistributed earnings of foreign subsidiaries as of December 31, 2012, were considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

As at December 31, 2012, the Company had operating loss carryforwards of \$213.1 million (December 31, 2011 - \$361.6 million) and capital losses of \$35.9 million (December 31, 2011 - \$13.7 million) before valuation allowance. Of these operating loss carryforwards and capital losses, \$215.2 million (December 31, 2011 - \$339.8 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between 2014 and 2032 and the capital losses expire between 2013 and 2017, while certain other jurisdictions allow operating losses to be carried forward indefinitely.

The valuation allowance increased by \$3.4 million during the year ended December 31, 2012. The change in the valuation allowance primarily related to 2012 losses in Brazil, Peru and the U.S. The Company continues to incur losses in the U.S., Peru, Brazil, Canada, Luxembourg and certain Argentina entities, which were only partially offset by adjustments for true up amounts to tax return actuals as well as the de-recognition of losses in Barbados upon the completion of a reorganization. The losses are fully offset by a valuation allowance as their recognition does not meet the “more likely than not” threshold.

As at December 31, 2012, the total amount of Gran Tierra’s unrecognized tax benefit was approximately \$21.8 million (December 31, 2011 - \$20.5 million; December 31, 2010 - \$4.2 million), a portion of which, if recognized, would affect the Company’s effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations. As at December 31, 2012, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the consolidated balance sheet was approximately \$3.6 million (December 31, 2011 - \$1.6 million). The Company had no other material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2012, respectively.

Changes in the Company's unrecognized tax benefit are as follows:

(Thousands of U.S. Dollars)	Year Ended December 31,	
	2012	2011
Unrecognized tax benefit, beginning of year	\$ 20,500	\$ 4,175
Changes for positions relating to prior year	1,300	585
Additions to tax position related to the current year	—	15,740
Unrecognized tax benefit, end of year	<u>\$ 21,800</u>	<u>\$ 20,500</u>

The Company and its subsidiaries file income tax returns in the U.S. and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for the tax years 2005 through 2012 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

The other gain for the year ended December 31, 2012, of \$9.3 million represented a value added tax recovery which occurred upon the completion of a reorganization of subsidiary companies and their Colombian branches in the Colombian reporting segment during the fourth quarter of 2012.

Equity tax for the year ended December 31, 2011, of \$8.3 million represented a Colombian tax of 6% on a legislated measure and was calculated based on the Company's Colombian segment's balance sheet equity for tax purposes at January 1, 2011. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period. The equity tax liability at December 31, 2012, and December 31, 2011, was also partially related to an equity tax liability assumed upon the acquisition of Petrolifera.

10. Accounts Payable and Accrued Liabilities

(Thousands of U.S. Dollars)	As at December 31,	
	2012	2011
Trade	\$ 103,720	\$ 71,384
Royalties	17,607	37,936
VAT and withholding tax	28,169	24,962
Other	19,185	14,739
	<u>\$ 168,681</u>	<u>\$ 149,021</u>

11. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of December 31, 2012:

(Thousands of U.S. Dollars)	Year ending December 31						
	Total	2013	2014	2015	2016	2017	Thereafter
Oil transportation services	\$ 28,354	\$ 5,077	\$ 3,405	\$ 3,405	\$ 3,405	\$ 3,405	\$ 9,657
Drilling and G&G	40,524	38,171	2,353	—	—	—	—
Completions	26,188	14,699	7,368	4,121	—	—	—
Facility construction	18,484	11,623	6,861	—	—	—	—
Operating leases	4,115	1,928	1,706	477	4	—	—
Software and telecommunication	1,744	1,538	74	9	123	—	—
Consulting	1,592	1,592	—	—	—	—	—
	<u>\$ 121,001</u>	<u>\$ 74,628</u>	<u>\$ 21,767</u>	<u>\$ 8,012</u>	<u>\$ 3,532</u>	<u>\$ 3,405</u>	<u>\$ 9,657</u>

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for the year ended December 31, 2012, was \$2.7 million (year ended December 31, 2011 – \$3.0 million; year ended December 31, 2010 - \$2.3 million).

Indemnities

Corporate indemnities have been provided by the Company to directors and officers for various items including, but not limited to, all costs to settle suits or actions due to their association with the Company and its subsidiaries and/or affiliates, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The maximum amount of any potential future payment cannot be reasonably estimated. The Company may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

Letters of credit

At December 31, 2012, the Company had provided promissory notes totaling \$34.2 million (December 31, 2011 - \$20.7 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contingencies

Ecopetrol and Gran Tierra Energy Colombia, Ltd. ("Gran Tierra Colombia"), the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long-term test of the Guayuyaco-1 and Guayuyaco-2 wells. There is a material difference in the interpretation of the procedure established in Clause 3.5 of Attachment-B of the Guayuyaco Association Contract. Ecopetrol interprets the contract to provide that the extended test production up to a value equal to 30% of the direct exploration costs of the wells is for Ecopetrol's account only and serves as reimbursement of its 30% back-in to the Guayuyaco discovery. Gran Tierra Colombia's contention is that this amount is merely the recovery of 30% of the direct exploration costs of the wells and not exclusively for the benefit of Ecopetrol. There has been no agreement between the parties, and Ecopetrol has filed a lawsuit in the Contravention Administrative Court in the District of Cauca regarding this matter. Gran Tierra Colombia filed a response on April 29, 2008, in which it refuted all of Ecopetrol's claims and requested a change of venue to the courts in Bogota. At this time, no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. Ecopetrol is claiming damages of approximately \$5.9 million.

Gran Tierra's production from the Costayaco field is subject to an additional royalty that applies when cumulative gross production from a commercial field is greater than five million barrels. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a non-compliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra's view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five million barrels. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process and filed an arbitration claim. As at December 31, 2012, total cumulative production from the Moqueta field was 0.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is \$15.1 million. At this time no amount has been accrued in the financial statements nor deducted from the Company's reserves as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra Colombia are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the additional royalty. Discussions with the ANH are ongoing. As at December 31, 2012, the estimated compensation which would be payable if the ANH's interpretation is successful is \$11.6 million. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

Gran Tierra is subject to a third party 10% net profits interest on 50% of Gran Tierra's production from the Chaza Block that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There was a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party agreed to resolve this issue through arbitration. The arbitration was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. Gran Tierra received the arbitrator's decision on May 24, 2012. The arbitrator ruled against Gran Tierra and as a result \$10.9 million became payable in relation to past production and was recorded as a revenue reduction in 2012. The arbitrator's decision will also increase future net profit interests payable to this third party, but is not expected to have a material impact on future results.

Gran Tierra has several lawsuits and claims pending. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, Gran Tierra believes the resolution of these matters would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. Gran Tierra records costs as they are incurred or become probable and determinable.

12. Financial Instruments, Fair Value Measurements and Credit Risk

At December 31, 2012, the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued liabilities and contingent consideration included in other long-term liabilities. The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. Contingent consideration, which relates to the acquisition of the remaining 30% working interest in certain properties in Brazil (Note 3), was recorded on the balance sheet at the acquisition date fair value based on the consideration expected to be transferred and discounted back to present value by applying an appropriate discount rate that reflected the risk factors associated with the payment streams. The discount rate used was determined at the time of measurement in accordance with accepted valuation methods. The fair value of the contingent consideration is being remeasured at the estimated fair value at each reporting period with the change in fair value recognized as income or expense in operating income (Note 3). The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2011, the Company did not have any financial assets or liabilities measured at fair value on the balance sheet. At December 31, 2012 and December 31, 2011, the Company held no derivative instruments. The Company does not use derivative financial instruments for speculative purposes.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. The fair value of the contingent consideration payable in connection with the Brazil acquisition at December 31, 2012 was determined using Level 3 inputs (Note 3). The disclosure in the paragraph above regarding the fair value of other financial instruments is based on Level 1 inputs.

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash and accounts receivables. The carrying value of cash and accounts receivable reflects management's assessment of credit risk .

At December 31, 2012, cash and cash equivalents and restricted cash included balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with governments and financial institutions with strong investment grade ratings, or the equivalent in the Company's operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in the Company's operating areas.

Most of the Company's accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the year ended December 31, 2012, the Company had one significant customer for its Colombian oil, Ecopetrol. In Argentina, the Company had two significant customers, Shell C.A.P.S.A. and Refineria del Norte S.A. .

For the year ended December 31, 2012, 84% (year ended December 31, 2011 - 91%, year ended December 31, 2010 - 96%) of our revenue and other income was generated in Colombia.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, monetary liabilities, which are mainly denominated in the local currency of the Colombian foreign operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at \$105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar .

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for Gran Tierra's Argentina subsidiaries to make payments. At December 31, 2012, \$16.4 million, or 8%, of our cash and cash equivalents was deposited with banks in Argentina. We expect to use to these funds for the work program and operations of Argentina in 2013.

13. Credit Facilities

Effective July 30, 2010, a subsidiary of Gran Tierra, Solana, established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve-based facility has a maximum borrowing base up to \$100 million and was supported by the present value of the petroleum reserves of two of the Company's subsidiaries with operating branches in Colombia, Gran Tierra Colombia and Petrolifera Petroleum Exploration (Colombia) Ltd , and the Company's subsidiary in Brazil - Gran Tierra Energy Brasil Ltda. The initial committed borrowing base was \$20 million. Effective August 2, 2012, the committed borrowing base was increased to \$50 million. Effective February 15, 2013, the borrowing base was increased to \$100 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. As at December 31, 2012, and December 31, 2011, the Company had not drawn down any amounts under this facility. On May 17, 2012, BNP Paribas sold Solana's credit facility to Wells Fargo Bank National Association, as part of the sale of its North American reserve-based lending business, without any modification to the facility. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility, and if the Company is not in default then it is required to obtain bank approval for any dividend payments exceeding \$2 million in any fiscal year.

14. Related Party Transactions

On January 12, 2011, the Company entered into an agreement to sublease office space to a company of which Gran Tierra's President and Chief Executive Officer serves as an independent director. The term of the sublease was from February 1, 2011 to January 30, 2013. and the sublease payment was \$4,500 per month plus approximately \$4,700 of operating and other expense; however, subsequent to September 30, 2012, the sublease was modified to terminate October 31, 2012, so that Gran Tierra can use this office space.

On August 7, 2012, Gran Tierra entered into a contract related to the Brazil drilling program with a company for which one of Gran Tierra's directors is a shareholder and director. During the year ended December 31, 2012, \$1.7 million was incurred and capitalized under this contract and at December 31, 2012, \$1.1 million was included in accounts payable relating to this contract. Similarly, on August 3, 2010, Gran Tierra entered into a contract related to the Peru drilling program with the same company and \$2.8 million was incurred and capitalized under this contract during the year ended December 31, 2011, and at December 31, 2011, \$nil was included in accounts payable relating to this contract.

On February 1, 2009, the Company entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was \$8,000 per month plus approximately \$4,700 for operating and other expenses.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations.

A. Reserve Quantity Information

Gran Tierra's net proved reserves and changes in those reserves for operations are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and 100% of the reserves have been evaluated by independent qualified reserves consultants, GLJ Petroleum Consultants.

Estimates of crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. See Critical Accounting Estimates in Item 7 for a description of Gran Tierra's reserves estimation process.

PROVED RESERVES NET OF ROYALTIES (1)

	Colombia		Argentina		Brazil		Total	
	Liquids (3) (Mbbbl)	Gas (MMcf)						
Proved developed and undeveloped reserves, December 31, 2009	20,791	1,113	1,291	756	—	—	22,082	1,869
Extensions and discoveries	3,107	—	43	—	—	—	3,150	—
Purchases of reserves in place	—	—	—	—	—	—	—	—
Production	(4,945)	(269)	(284)	—	—	—	(5,229)	(269)
Revisions of previous estimates	3,532	388	62	(756)	—	—	3,594	(368)
Proved developed and undeveloped reserves, December 31, 2010	22,485	1,232	1,112	—	—	—	23,597	1,232
Extensions and discoveries	4,009	—	47	—	—	—	4,056	—
Purchases of reserves in place	238	13,797	4,639	4,825	396	—	5,273	18,622
Production	(5,349)	(268)	(727)	(1,143)	(43)	—	(6,119)	(1,411)
Revisions of previous estimates	4,042	(121)	72	—	—	—	4,114	(121)
Proved developed and undeveloped reserves, December 31, 2011	25,425	14,640	5,143	3,682	353	—	30,921	18,322
Extensions and discoveries	4,680	921	1,731	56	1,006	—	7,417	977
Purchases of reserves in place	—	—	—	—	222	—	222	—
Production	(5,200)	(138)	(1,049)	(1,346)	(107)	—	(6,356)	(1,484)
Revisions of previous estimates	6,204	(5,951)	(32)	912	117	—	6,289	(5,039)
Proved developed and undeveloped reserves, December 31, 2012	31,109	9,472	5,793	3,304	1,591	—	38,493	12,776
Proved developed reserves, December 31, 2010 (2)	18,528	1,232	940	—	—	—	19,468	1,232
Proved developed reserves, December 31, 2011 (2)	20,899	13,927	1,918	3,351	54	—	22,871	17,278
Proved developed reserves, December 31, 2012 (2)	24,677	8,551	2,459	2,777	347	—	27,483	11,328
Proved undeveloped reserves, December 31, 2010	3,957	—	172	—	—	—	4,129	—
Proved undeveloped reserves, December 31, 2011	4,526	713	3,225	331	299	—	8,050	1,044
Proved undeveloped reserves, December 31, 2012	6,432	921	3,334	527	1,244	—	11,010	1,448

(1) Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered “proved” if they can be produced economically, as demonstrated by either actual production or conclusive formation testing.

(2) Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

(3) Liquids include oil and NGLs. We have NGL reserves in small amounts in Colombia and Argentina only. Brazil liquids reserves are 100% oil.

B. Capitalized Costs

	Proved Properties	Unproved Properties	Accumulated depletion, depreciation and impairment	Capitalized Costs
Colombia	\$ 969,291	\$ 274,777	\$ (429,526)	\$ 814,542
Argentina	159,958	56,975	(89,692)	127,241
Brazil	10,836	52,440	(1,884)	61,392
Peru	—	33,675	—	33,675
Balance, December 31, 2011	\$ 1,140,085	\$ 417,867	\$ (521,102)	\$ 1,036,850
Colombia	\$ 1,219,640	\$ 175,871	\$ (558,423)	\$ 837,088
Argentina	215,030	42,284	(120,649)	136,665
Brazil	84,807	70,129	(28,158)	126,778
Peru	—	96,130	—	96,130
Balance, December 31, 2012	\$ 1,519,477	\$ 384,414	\$ (707,230)	\$ 1,196,661

C. Costs Incurred

	Colombia	Argentina	Brazil	Total
Balance, December 31, 2009	\$ 837,367	\$ 40,191	\$ —	\$ 877,558
Property acquisition costs				
Proved	—	—	—	—
Unproved	—	—	—	—
Exploration costs	63,115	26,404	—	89,519
Development costs	41,057	7,248	—	48,305
Balance, December 31, 2010	941,539	73,843	—	1,015,382
Property acquisition costs				
Proved	—	58,458	4,601	63,059
Unproved	114,993	49,784	35,285	200,062
Exploration costs	54,486	11,270	17,225	82,981
Development costs	133,121	23,749	5,923	162,793
Balance, December 31, 2011	1,244,139	217,104	63,034	1,524,277
Property acquisition costs				
Proved	24,403	—	24,106	48,509
Unproved	—	—	37,309	37,309
Exploration costs	32,472	1,310	19,128	52,910
Development costs	95,415	38,044	10,297	143,756
Balance, December 31, 2012	\$ 1,396,429	\$ 256,458	\$ 153,874	\$ 1,806,761

D. Results of Operations for Oil and Gas Producing Activities

	Colombia	Argentina	Brazil	Total
Year Ended December 31, 2010				
Oil and natural gas sales	\$ 359,302	\$ 13,984	\$ —	\$ 373,286
Production costs	(50,431)	(8,808)	—	(59,239)
Exploration expenses	—	—	—	—
DD&A expenses	(132,050)	(29,426)	—	(161,476)
Income tax expense	(51,047)	(5,687)	—	(56,734)
Results of Operations	125,774	(29,937)	—	95,837
Year Ended December 31, 2011				
Oil and natural gas sales	543,999	48,016	4,176	596,191
Production costs	(58,081)	(27,076)	(1,018)	(86,175)
Exploration expenses	—	—	—	—
DD&A expenses	(141,133)	(45,506)	(1,819)	(188,458)
Income tax expense	(114,255)	5,489	—	(108,766)
Results of Operations	230,530	(19,077)	1,339	212,792
Year Ended December 31, 2012				
Oil and natural gas sales	493,615	79,642	9,852	583,109
Production costs	(87,410)	(32,696)	(4,637)	(124,743)
Exploration expenses	—	—	—	—
DD&A expenses	(122,055)	(31,466)	(26,300)	(179,821)
Income tax expense	(95,042)	(1,412)	—	(96,454)
Results of Operations	\$ 189,108	\$ 14,068	\$ (21,085)	\$ 182,091

E. Standardized Measure of Discounted Future Net Cash Flows and Changes

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions to Gran Tierra's after royalty share of estimated annual future production from proved oil and gas reserves. The 2012 twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within that twelve month period was \$103.57 (2011 - \$95.20; 2010 - \$71.50) for Colombia, \$66.12 (2011 - \$54.26; 2010 - \$50.18) for Argentina and \$95.38 (2011 - \$97.07; 2010 - \$nil) for Brazil. The calculated weighted average production costs at December 31, 2012, were \$18.49 (2011 - \$10.10; 2010 - \$10.48) for Colombia, \$22.99 (2011 - \$28.50; 2010 - \$18.87) for Argentina and \$5.71 (2011 - \$15.65; 2010 - \$nil) for Brazil. Future development and production costs to be incurred in producing and further developing the proved reserves are based on year end cost indicators. Future income taxes are computed by applying year end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows. Discounted future net cash flows are calculated using 10% mid-year discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

The Company believes this information does not in any way reflect the current economic value of its oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period.

	<u>Colombia</u>	<u>Argentina</u>	<u>Brazil</u>	<u>Total</u>
December 31, 2010				
Future cash inflows	1,621,461	55,833	—	1,677,294
Future production costs	(373,467)	(27,314)	—	(400,781)
Future development costs	(136,688)	(4,965)	—	(141,653)
Future asset retirement obligations	(8,070)	(385)	—	(8,455)
Future income tax expense	(295,146)	—	—	(295,146)
Future net cash flows	808,090	23,169	—	831,259
10% discount	(225,990)	(4,270)	—	(230,260)
Standardized Measure of Discounted Future Net Cash Flows	582,100	18,899	—	600,999
December 31, 2011				
Future cash inflows	2,535,662	331,554	34,244	2,901,460
Future production costs	(459,955)	(179,277)	(11,667)	(650,899)
Future development costs	(145,513)	(50,742)	(4,900)	(201,155)
Future asset retirement obligations	(12,420)	(3,063)	(525)	(16,008)
Future income tax expense	(500,700)	(18,207)	(1,215)	(520,122)
Future net cash flows	1,417,074	80,265	15,937	1,513,276
10% discount	(369,112)	(26,274)	(2,543)	(397,929)
Standardized Measure of Discounted Future Net Cash Flows	1,047,962	53,991	13,394	1,115,347
December 31, 2012				
Future cash inflows	3,283,618	423,867	151,726	3,859,211
Future production costs	(915,035)	(193,434)	(17,758)	(1,126,227)
Future development costs	(204,658)	(61,165)	(27,550)	(293,373)
Future asset retirement obligations	(13,360)	(3,681)	(1,750)	(18,791)
Future income tax expense	(584,762)	(44,023)	—	(628,785)
Future net cash flows	1,565,803	121,564	104,668	1,792,035
10% discount	(428,616)	(36,006)	(29,961)	(494,583)
Standardized Measure of Discounted Future Net Cash Flows	1,137,187	85,558	74,707	1,297,452

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	2012	2011	2010
Balance, December 31, 2011	1,115,347	\$ 600,999	\$ 406,384
Sales and transfers of oil and gas produced, net of production costs	(457,095)	(491,046)	(313,840)
Net changes in prices and production costs related to future production	162,623	446,111	208,649
Extensions, discoveries and improved recovery, less related costs	342,906	206,762	32,194
Previously estimated development costs incurred during the year	90,801	106,291	107,856
Revisions of previous quantity estimates	286,995	242,761	140,893
Accretion of discount	149,850	81,422	58,043
Purchases of reserves in place	10,422	93,071	—
Sales of reserves in place	—	—	—
Net change in income taxes	(198,808)	(148,529)	(39,180)
Changes in future development costs	(205,589)	(22,495)	—
Net increase	182,105	514,348	194,615
Balance, December 31, 2012	1,297,452	1,115,347	600,999

2) Summarized Quarterly Financial Information

	Revenue and other Income	Expenses	Income before income taxes	Income taxes	Net (loss) income	Net (loss) income per share - basic	Net (loss) income per share - diluted
2012							
First quarter	155,951	125,128	30,823	(31,136)	(313)	0.00	0.00
Second quarter	115,150	82,310	32,840	(19,736)	13,104	0.05	0.05
Third quarter	168,933	92,920	76,013	(31,408)	44,605	0.16	0.16
Fourth quarter	145,153	87,466	57,687	(15,424)	42,263	0.15	0.15
	585,187	387,824	197,363	(97,704)	99,659	0.35	0.35
2011							
First quarter	122,519	82,110	40,409	(26,696)	13,713	0.05	0.05
Second quarter	162,120	102,560	59,560	(27,993)	31,567	0.11	0.11
Third quarter	151,033	71,974	79,059	(29,974)	49,085	0.18	0.17
Fourth quarter	161,735	106,516	55,219	(22,667)	32,552	0.12	0.12
	597,407	363,160	234,247	(107,330)	126,917	0.46	0.45

In March 2011, we acquired Petrolifera Petroleum Limited.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule 13a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of December 31, 2012 to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Gran Tierra's management is responsible for establishing and maintaining adequate internal control over financial reporting for Gran Tierra, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of Gran Tierra's management, including our principal executive and principal financial officers, Gran Tierra conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework, management concluded that its internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of Gran Tierra's internal control over financial reporting as of December 31, 2012 has been audited by Deloitte LLP, independent registered chartered accountants, as stated in their report which appears herein.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Gran Tierra Energy Inc.

We have audited the internal control over financial reporting of Gran Tierra Energy Inc. and subsidiaries (the "Company") as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and our report dated February 26, 2013 expressed an unqualified opinion on those financial statements.

/s/ Deloitte LLP

Independent Registered Chartered Accountants

Calgary, Canada

February 26, 2013

Item 9B. Other Information

None.

PART III**Item 10. Directors, Executive Officers and Corporate Governance**

The information required regarding our directors is incorporated herein by reference from the information contained in the section entitled "Proposal 1 - Election of Directors" in our definitive Proxy Statement for the 2013 Annual Meeting of Stockholders (our "Proxy Statement"), a copy of which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2012. For information with respect to our executive officers, see "Executive Officers of the Registrant" at the end of Part I of this report, following Item 4.

The information required regarding Section 16(a) beneficial ownership reporting compliance is incorporated by reference from the information contained in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement.

The information required with respect to procedures by which security holders may recommend nominees to our Board of Directors, the composition of our Audit Committee, and whether we have an "audit committee financial expert", is incorporated by reference from the information contained in the section entitled "Proposal 1 - Election of Directors" in our Proxy Statement.

Adoption of Code of Ethics

Gran Tierra has adopted a Code of Business Conduct and Ethics (the "Code") applicable to all of its Board members, employees and executive officers, including its Chief Executive Officer (Principal Executive Officer), and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer). Gran Tierra has made the Code available on its website at <http://www.grantierra.com/corporate-responsibility.html>.

Gran Tierra intends to satisfy the public disclosure requirements regarding (1) any amendments to the Code, or (2) any waivers under the Code given to Gran Tierra's Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer by posting such information on its website at <http://www.grantierra.com/corporate-responsibility.html>. There were no amendments to the Code or waivers granted thereunder relating to the Principal Executive Officer, Principal Financial Officer or Principal Accounting Officer during 2012.

Item 11. Executive Compensation

The information required regarding the compensation of our directors and executive officers is incorporated herein by reference from the information contained in the section entitled "Executive Compensation and Related Information" in our Proxy Statement, including under the subheadings "Director Compensation," "Compensation Committee Report" and "Compensation Committee Interlocks and Insider Participation".

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required regarding security ownership of our 10% or greater stockholders and of our directors and management is incorporated herein by reference from the information contained in the section entitled "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement.

The following table provides certain information with respect to securities authorized for issuance under Gran Tierra's equity compensation plans in effect as of the end of December 31, 2012:

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of options	Weighted average exercise price of outstanding options	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	15,399,662	5.11	17,732,804
Equity compensation plans not approved by security holders	—	—	—
	15,399,662	5.11	17,732,804

The only equity compensation plan approved by our stockholders is our 2007 Equity Incentive Plan, which is an amendment and restatement of our 2005 Equity Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required regarding related transactions is incorporated herein by reference from the information contained in the section entitled "Certain Relationships and Related Transactions" and, with respect to director independence, the section entitled "Proposal 1 - Election of Directors", in our Proxy Statement.

Item 14. Principal Accounting Fees and Services

The information required is incorporated herein by reference from the information contained in the sections entitled "Principal Accountant Fees and Services" and "Pre-Approval Policies and Procedures" in the proposal entitled "Ratification of Selection of Independent Auditors" in our Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

The following documents are included as Part II, Item 8. of this Annual Report on Form 10-K:

	Page
Report of Independent Registered Chartered Accountants	88
Consolidated Statements of Operations and Retained Earnings	89
Consolidated Balance Sheets	90
Consolidated Statements of Cash Flow	91
Consolidated Statements of Shareholders' Equity	92
Notes to the Consolidated Financial Statements	93
Supplementary Data (Unaudited)	113

(2) Financial Statement Schedules

None.

(3) Exhibits

See the Exhibit Index which follows the signature page of this Annual Report on Form 10-K, which is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GRAN TIERRA ENERGY INC.

Date: February 26, 2013

/s/ Dana Coffield

By: Dana Coffield
Chief Executive Officer and President
(Principal Executive Officer)

Date: February 26, 2013

/s/ James Rozon

By: James Rozon
Chief Financial Officer
(Principal Financial and Accounting Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Dana Coffield and James Rozon, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

<u>Name</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Dana Coffield</u> Dana Coffield	Chief Executive Officer and President (Principal Executive Officer)	February 26, 2013
<u>/s/ James Rozon</u> James Rozon	Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2013
<u>/s/ Jeffrey Scott</u> Jeffrey Scott	Chairman of the Board, Director	February 26, 2013
<u>/s/ Verne Johnson</u> Verne Johnson	Director	February 26, 2013
<u>/s/ Nicholas G. Kirton</u> Nicholas G. Kirton	Director	February 26, 2013
<u>/s/ J. Scott Price</u> J. Scott Price	Director	February 26, 2013
<u>/s/ Ray Antony</u> Ray Antony	Director	February 26, 2013
<u>/s/ Gerry Macey</u> Gerry Macey	Director	February 26, 2013

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1	Arrangement Agreement, dated as of July 28, 2008, by and among Gran Tierra Energy Inc., Solana Resources Limited and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (SEC File No. 001-34018), filed with the SEC on August 1, 2008.
2.2	Amendment No. 2 to Arrangement Agreement, which supersedes Amendment No. 1 thereto and includes the Plan of Arrangement, including appendices.	Incorporated by reference to Exhibit 2.2 to the Registration Statement on Form S-3 (SEC File No. 333-153376), filed with the SEC on October 10, 2008.
2.3	Arrangement Agreement, dated January 17, 2011, by and between Gran Tierra Energy Inc. and Petrolifera Petroleum Limited. †	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (SEC File No. 001-34018).
3.1	Amended and Restated Articles of Incorporation.	Incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q/A (SEC File No. 001-34018), filed with the SEC on January 6, 2010.
3.2	Amended and Restated Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed with the SEC on September 22, 2008 (SEC File No. 000-52594).
4.1	Reference is made to Exhibits 3.1 to 3.2.	
4.2	Details of the Goldstrike Special Voting Share.	Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.3	Goldstrike Exchangeable Share Provisions.	Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005 and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.4	Provisions Attaching to the GTE–Solana Exchangeable Shares.	Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the SEC on October 14, 2008 (SEC File No. 001-34018).
10.1	Voting Exchange and Support Agreement by and between Goldstrike, Inc., 1203647 Alberta Inc., Gran Tierra Goldstrike Inc. and Olympia Trust Company dated as of November 10, 2005.	Incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (SEC File No. 333-111656).
10.2	Voting and Exchange Trust Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Exchangeco Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2008 (SEC File No. 001-34018).
10.3	Support Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Callco ULC and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on November 17, 2008 (SEC File No. 001-34018).
10.4	Amended and Restated 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2012 (SEC File No. 001-34018).
10.5	Form of Option Agreement under the Company's 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 99.1 to the current report on Form 8-K filed with the Securities and Exchange Commission on December 21, 2007 (SEC File No. 000-52594).
10.6	Form of Grant Notice under the Company's 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 99.2 to the current report on Form 8-K filed with the Securities and Exchange Commission on December 21, 2007 (SEC File No. 000-52594).

10.7	Form of Exercise Notice under the Company's 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 99.3 to the current report on Form 8-K filed with the Securities and Exchange Commission on December 21, 2007 (SEC File No. 000-52594).
10.8	Form of Indemnity Agreement. *	Incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 2, 2008 (SEC File No. 000-52594).
10.9	2005 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.11 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (SEC File No. 333-111656).
10.10	2011 Executive Officer Cash Bonus Compensation and 2012 Cash Compensation Arrangements. *	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K/A, filed with the SEC on April 3, 2012, with respect to 2011 Cash Bonus Compensation, and to Exhibit 10.7 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012, with respect to 2012 Cash Compensation Arrangements (SEC File No. 001-34018).
10.11	2010 Executive Officer Cash Bonus Compensation and 2011 Cash Compensation Arrangements. *	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 9, 2011, with respect to the 2010 Executive Officer Cash Bonus Compensation, and incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 with respect to 2011 Cash Compensation Arrangements (in each case, SEC File No. 001-34018).
10.12	Employment Agreement, dated November 4, 2008, between Gran Tierra Energy Inc. and Dana Coffield. *	Incorporated by reference to Exhibit 10.57 to the Annual Report on Form 10-K, filed with the SEC on February 27, 2009 (SEC File No. 001-34018).
10.13	Employment Agreement, dated June 17, 2008, between Gran Tierra Energy Inc. and Martin Eden. *	Incorporated by reference to Exhibit 10.58 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.14	Employment Agreement, dated June 17, 2008, between Gran Tierra Energy Inc. and Rafael Orunesu. *	Incorporated by reference to Exhibit 10.61 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.15	Offer Letter between Gran Tierra Energy Inc. and Shane P. O'Leary dated January 26, 2009. *	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on February 4, 2009 (SEC File No. 001-34018).
10.16	Employment Agreement between Gran Tierra Energy Inc. and Shane P. O'Leary dated as of January 26, 2009. *	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on February 4, 2009 (SEC File No. 001-34018).
10.17	Employment Agreement, dated July 1, 2009, between Gran Tierra Energy Inc. and Julio César Moreira. *	Incorporated by reference to Exhibit 10.62 to the Annual Report on Form 10-K for the period ended December 31, 2009, and filed with the Securities and Exchange on February 26, 2010 (SEC File No. 001-34018).
10.18	Colombian Participation Agreement, dated as of June 22, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.55 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 333-111656).
10.19	Amendment No. 1 to Colombian Participation Agreement, dated as of November 1, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.56 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.20	Amendment No. 2 to Colombian Participation Agreement, dated as of July 3, 2008, between Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q/A, filed with the SEC on November 19, 2008 (SEC File No. 001-34018).

10.21	Amendment No. 3 to Participation Agreement, dated as of December 31, 2008, by and among Gran Tierra Energy Colombia, Ltd., Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 7, 2009 (SEC File No. 001-34018).
10.22	Form of Voting Support Agreement Respecting the Arrangement Involving Petrolifera Petroleum Limited and Gran Tierra Energy Inc. (Petrolifera Directors and Officers)	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (SEC File No. 001-34018).
10.23	Form of Voting Support Agreement Respecting the Arrangement Involving Petrolifera Petroleum Limited and Gran Tierra Energy Inc. (Petrolifera largest stockholder)	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (SEC File No. 001-34018).
10.24	Credit Agreement, dated as of July 30, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., the Lenders party thereto, and BNP Paribas.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on August 5, 2010 (SEC File No. 001-34018).
10.25	First Amendment to Credit Agreement, dated as of August 30, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2010 (SEC File No. 001-34018).
10.26	Second Amendment to Credit Agreement, dated as of November 5, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders.	Incorporated by reference to Exhibit 10.46 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (SEC File No. 001-34018).
10.27	Third Amendment to Credit Agreement, dated as of January 20, 2011, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders.	Incorporated by reference to Exhibit 10.47 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (SEC File No. 001-34018).
10.28	Agreement between Gran Tierra Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 15, 2010 (SEC File No. 001-34018).
10.29	Amendment No. 1, executed November 8, 2010, to Agreement between Gran Tierra Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 15, 2010 (SEC File No. 001-34018).
10.30	Addendum, entered into between Gran Tierra Colombia Ltd. and Ecopetrol S.A. on December 30, 2010, amending the Agreement between those parties dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (SEC File No. 001-34018).
10.31	Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (SEC File No. 001-34018).
10.32	Amendment No. 1, executed November 8, 2010, to Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (SEC File No. 001-34018).

10.33	Addendum, entered into between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A. on December 30, 2010, amending the Agreement between those parties dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (SEC File No. 001-34018).
10.34	Addendum No. 2, entered into between Gran Tierra Colombia Ltd. and Ecopetrol S.A. on December 30, 2010, amending the Agreement between those parties dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (SEC File No. 001-34018).
10.35	Addendum No. 2, entered into between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A. on June 30, 2011, amending the Agreement between those parties dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (SEC File No. 001-34018).
10.36	Contract, dated July 27, 2011, between Gran Tierra Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (SEC File No. 001-34018).
10.37	Contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (SEC File No. 001-34018).
10.38	Executive Employment Agreement dated July 30, 2009, between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (SEC File No. 001-34018).
10.39	Expatriate Assignment Agreement to Gran Tierra Colombia Ltd., dated December 7, 2010, between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (SEC File No. 001-34018).
10.40	Employment Contract dated January 31, 2011, between Gran Tierra Colombia Ltd. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (SEC File No. 001-34018).
10.41	Amendment to Expatriate Assignment Agreement, dated October 13, 2011, between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (SEC File No. 001-34018).
10.42	Consulting Services Agreement, between David Hardy and Gran Tierra Energy Inc. *	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 (SEC File No. 001-34018).
10.43	Executive Employment Agreement, dated January 20, 2010, between Gran Tierra Energy Inc. and David Hardy. *	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 (SEC File No. 001-34018).
10.44	Notice of termination of contract dated December 2, 2011, regarding the contract dated July 27, 2011, between Gran Tierra Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).

10.45	Notice of termination of contract dated December 2, 2011, regarding the contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).
10.46	Amendment dated December 22, 2011, to notice of termination of contract dated December 2, 2011, regarding the contract dated July 27, 2011, between Gran Tierra Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.55 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).
10.47	Amendment dated December 22, 2011, to notice of termination of contract dated December 2, 2011, regarding the contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.56 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).
10.48	Employment Agreement between Gran Tierra Energy Inc. and James Rozon dated as of September 10, 2007. *	Incorporated by reference to Exhibit 10.57 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).
10.49	Amendment dated January 30, 2012, to contract, dated July 27, 2011, between Gran Tierra Colombia Ltd and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.58 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).
10.50	Amendment dated January 30, 2012, to contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.59 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 27, 2012 (SEC File No. 001-34018).
10.51	Amendment No. 4 dated June 13, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.52	Amendment No. 5 dated February 10, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.53	Agreement between Gran Tierra Colombia Ltd and Ecopetrol S.A., dated January 30, 2012, with respect to the transportation of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.54	Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., dated January 30, 2012, with respect to the transportation of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.55	Fourth Amendment to Credit Agreement, dated as of February 14, 2012, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders.	Incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.56	Amendment No. 6 dated March 1, 2012, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).

10.57	Amendment to Employment Agreement dated May 2, 2012, between Gran Tierra Energy Inc. and Martin Eden.	Incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.58	Amendment to Employment Agreement dated May 2, 2012, between Gran Tierra Energy Inc. and David Hardy.	Incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.59	Executive Employment Agreement dated May 2, 2012, between Gran Tierra Energy Inc. and James Rozon.	Incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.60	Resignation, Consent and Appointment Agreement and Amendment Agreement, effective May 17, 2012, assigning the Credit Agreement among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Lenders, to Wells Fargo Bank, National Association.	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2012 (SEC File No. 001-34018).
10.61	Fifth Amendment to Credit Agreement, dated as of May 18, 2012, among Solana Resources Limited, Gran Tierra Energy Inc. Wells Fargo Bank, National Association, and the Lenders.	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2012 (SEC File No. 001-34018).
10.62	Addendum No. 2 to the Purchase Agreement between Gran Tierra Energy Colombia, Ltd. and Ecopetrol S.A. with respect to the sale of crude oil from the Chaza Block, Santana Block and Guayuyaco Block.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 7, 2012 (SEC File No. 001-34018).
10.63	Addendum No. 2 to the Purchase Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A. with respect to the sale of crude oil from the Chaza Block, Santana Block and Guayuyaco Block.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 7, 2012 (SEC File No. 001-34018).
10.64	Addendum No. 1 to the Transportation Agreement between Gran Tierra Energy Colombia, Ltd. and Ecopetrol S.A.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 7, 2012 (SEC File No. 001-34018).
10.65	Addendum No. 1 to the Transportation Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A.	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 7, 2012 (SEC File No. 001-34018).
10.66	Sixth Amendment to Credit Agreement, dated as of October 9, 2012, among Solana Resources Limited, Gran Tierra Energy Inc., Wells Fargo Bank, National Association, and the Lenders.	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 7, 2012 (SEC File No. 001-34018).
10.67	Agreement between Gran Tierra Energy Colombia, Ltd and Ecopetrol S.A., dated December 1, 2012, with respect to the sale of crude oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.
10.68	Agreement between Petrolifera Petroleum Exploration (Colombia) Limited and Ecopetrol S.A., dated December 1, 2012, with respect to the sale of crude oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.
10.69	Agreement between Gran Tierra Colombia Ltd and Gunvor Colombia SAS, dated December 3, 2012, with respect to the sale of crude oil.	Filed herewith.
10.70	Agreement between Petrolifera Petroleum Exploration (Colombia) Limited and Gunvor Colombia SAS, dated December 3, 2012, with respect to the sale of crude oil.	Filed herewith.

10.71	Seventh Amendment to Credit Agreement, dated as of January 17, 2013, among Solana Resources Limited, Gran Tierra Energy Inc., Wells Fargo Bank, National Association, and the Lenders.	Filed herewith.
10.72	Addendum No. 3 to the Transportation Agreement between Gran Tierra Energy Colombia, Ltd. and Ecopetrol S.A.	Filed herewith.
10.73	Addendum No. 3 to the Transportation Agreement between Petrolifera Petroleum (Colombia) Ltd. and Ecopetrol S.A.	Filed herewith.
10.74	Notice dated February 15, 2013, from Wells Fargo Bank that the borrowing base amount for the Solana Resources Ltd credit facility has been increased and the increase is effective.	Filed herewith.
10.75	2012 Executive Officer Cash Bonus Compensation and 2013 Cash Compensation Arrangements. *	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 13, 2013, with respect to 2012 Cash Bonus Compensation and 2012 Cash Compensation Arrangements (SEC File No. 001-34018).
10.76	Chaza Block Hydrocarbons Exploration and Exploitation Agreement between Argosy Energy International and the National Hydrocarbons Agency dated June 25, 2005.	Filed herewith.
10.77	Addendum No. 1 to the Chaza Block Hydrocarbons Exploration and Exploitation Agreement between Argosy Energy International and the National Hydrocarbons Agency.	Filed herewith.
21.1	List of subsidiaries.	Filed herewith.
23.1	Consent of Deloitte LLP.	Filed herewith.
23.2	Consent of GLJ Petroleum Consultants.	Filed herewith.
24.1	Power of Attorney.	See signature page.
31.1	Certification of Principal Executive Officer.	Filed herewith.
31.2	Certification of Principal Financial Officer.	Filed herewith.
32.1	Section 1350 Certifications.	Filed herewith.
99.1	Gran Tierra Energy Inc. Reserves Assessment and Evaluation of Colombian, Argentina and Brazilian Oil and Gas Properties Corporate Summary, effective December 31, 2012.	Filed herewith.
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	

+ Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Gran Tierra undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

* Management contract or compensatory plan or arrangement.

CONTRACT: VSM-GPS-050-2012

PURPOSE: PURCHASE - SALE OF CRUDE CHAZA, SANTANA and GUAYUYACO

SELLER: GRAN TIERRA ENERGY COLOMBIA LTD

VALUE: UNDETERMINED

The contracting parties, namely: **ECOPETROL S.A.**, national decentralized entity, created through Law 165 of 1948, with TIN 899.999.068-1, organized as Mixed Economy Corporation, based on the provisions of Article 2 of Law 1118 of 2006, ascribed to the Ministry of Mines and Energy, with main domicile in Bogotá D.C., which By-Laws are integrally contained in Public Deed No. 5314 of December 14, 2007, issued at Notary Public Office Two of the Bogota D.C. Notary Circle and registered at the Chamber of Commerce of Bogota D.C., which shall hereinafter for all purposes be referred to as the **BUYER**, represented herein by **BERNARDO CASTRO CASTRO** of age, and resident of this city, identified with Colombian Identity Card No. 79.295.921 issued in Bogotá, who in his condition of **Planning and Supply Manager** and in furtherance of the authorization contained in the Authority Delegations Manual of ECOPEPETROL S.A. acts on behalf of, and in representation of this Company and, on the other, **GRAN TIERRA ENERGY COLOMBIA LTD**, with TIN 860.516.431-7, hereinafter the **SELLER** and jointly represented herein by **DUNCAN NIGHTINGALE**, identified with passport No. BA286341, acting in his capacity of Legal Representative and **ALEJANDRA ESCOBAR HERRERA**, identified with Colombian Identity Card No. 52.646.943 who acts in her capacity of Legal Representative and are duly authorized to enter into this Contract, as evidenced in the Certificate of Good Standing attached hereto, and who have stated that neither of them, or the company they represent are involved in any grounds for inability or incompatibility foreseen in the Political Constitution or in the Law, which may prevent them from entering into this Agreement.

In the foregoing conditions, **the BUYER** and the **SELLER**, who shall jointly be referred to as the Parties and individually the Party, agree to subscribe to this Contract, prior the following:

CONSIDERATIONS AND REPRESENTATIONS

1. That on June 27, 2005, the **Agencia Nacional de Hidrocarburos (ANH)** and the **SELLER** entered into a Hydrocarbon Exploration and Production Contract denominated Chaza.
2. That on September 30, 2002, **ECOPETROL S.A.** and **the SELLER** entered into an Association Contract denominated Guayuyaco.
3. That on July 27, 1987, **ECOPETROL S.A.** and **the SELLER** entered into a Risk Share Contract (CPR-Santana).

4. That the **SELLER** declares under oath, which is understood as made upon signing this document, that it holds fifty percent (50%) of the crude production from the Chaza field, thirty five percent (35%) of the Guayuyaco field and thirty five percent (35%) of the Santana field; (hereinafter the "Fields"), which shall be committed herein after deducting the percentage corresponding to royalties.
5. That for the purposes herein, the **SELLER** has signed contracts with the **VICE PRESIDENCY OF TRANSPORT AND LOGISTICS OF ECOPETROL S.A.**, the purpose of which is to render liquid hydrocarbon transport services through the **Oleoducto Transandino - OTA**.
6. That the contract signed by the **SELLER** and the **VICE PRESIDENCY OF TRANSPORT AND LOGISTICS OF ECOPETROL S.A.** is an essential consideration to subscribe to this Agreement.
7. That for purposes of carrying out this Contract, the **SELLER** has or will enter into a contract with the **VICE PRESIDENCY OF PRODUCTION OF ECOPETROL S.A.**, the purpose of which is to unload at the Dina Station and this contract is an essential consideration for the subscription of this Contract.
8. That for purposes of subscribing to this Contract, the **BUYER** previously verified in the Taxpayer Bulletin prepared and published by the General Comptroller's Office of the Republic, that the **SELLER** is not listed in such bulletin as one of the persons having a firm taxpayer liability verdict in force, and who have not fulfilled the obligation therein contained. Likewise, the **BUYER** implemented the control mechanisms related to asset laundering prevention and developed the instruments for the correct enforcement thereof, in furtherance of the Asset Laundering Prevention and Terrorism Financing Policy.
9. That on November 9, 2012, **the BUYER** held a meeting to review the crude purchasing negotiation conditions derived from the Santana Risk Share Contract (CPR-Santana), the Guayuyaco Association Contract and the Chaza Block **to GRAN TIERRA ENERGY COLOMBIA LTD.**
10. That as provided for in the Authority Delegations Manual of **ECOPETROL S.A.**, the **Planning and Supply Manager** is competent to subscribe to this Contract.
11. That the **BUYER** in its expenditure budget, owns the respective budget availability to execute the Contract referred to in this document.
12. That pursuant to the provisions of the Contracting Manual of **ECOPETROL S.A.** and after analyzing the nature and the form of execution of the provisions in charge of the Parties in furtherance of this Contract, the Authorized Official has qualified the risk as low and, consequently, abstains from requesting a security to **the SELLER**.

13. That based on the contractual planning made, consultation was made with the Tax Consultancy and Management Coordination of **ECOPETROL S.A.**, in order to avoid any tax risk that could be accrued for the Company as a consequence of the entering into and execution of this Contract.
14. That the **BUYER** verified compliance of its obligations with the social security system by the **SELLER** through a certificate signed by the statutory auditor of the **SELLER**.
15. In furtherance of the Asset Laundering Prevention and Terrorism Financing Policy adopted by the **BUYER**, the Legal Representative of the **SELLER** declares, under oath, subject to the sanctions set out in the Penal Code:
- I. That my funds (or the funds of the entity I represent) are derived from legal activities and are related to the normal course of my activities (or the activities inherent to the corporate purpose of the company I represent) and that they are not derived from any of the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it.
 - II. That I (or the entity I represent) have not made any transactions or operations aimed at the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it, or in favor of persons related to such activities.
 - III. That the resources committed in the contract or legal relation with the **BUYER** are not derived from any of the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it.
 - IV. That in furtherance of the contract execution or legal relation with the **BUYER**, I will not engage nor will I have relations with third parties carrying out operations or whose resources are derived from the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it.
 - V. That the entity I represent complies with the norms regarding asset laundering prevention and control and terrorism financing (LA/FT in Spanish), as applicable (as the case may be), after implementing the policies, procedures and mechanisms to prevent and control LA/FT, as derived from such legal provisions. Certification model is attached as Annex 1.
 - VI. That neither I or the entity I represent, or its shareholders, partners or associates who directly or indirectly own FIVE PERCENT (5%) or more of the capital stock, contribution or share, its legal representatives and members of the Board of Directors are included in international lists which may be binding for Colombia, pursuant to the international law (UN lists) or in the OFAC lists, being the **BUYER** empowered to make the verifications deemed convenient and to terminate any commercial or legal relation if confirming that any of such persons are included in such lists. Certification model is attached as Annex 2.
 - VII. That against me, or against the entity I represent or its shareholders, associates or partners who directly or indirectly have FIVE PERCENT (5%) or more of the capital stock, contribution or share, its legal representatives and members of the Board of Directors, there are no investigations or criminal processes for INTENTIONAL CRIMES, being the **BUYER** empowered to make the verifications deemed convenient in databases or national or international public information and to terminate any commercial or legal relation if confirming that any of such persons are involved

- in such investigations or processes or if such databases include information that may expose the **BUYER** to a legal or reputation risk.
- VIII. That in the event that any of the circumstances described in the two above paragraphs, I undertake to communicate it forthwith to the **BUYER**.
- IX. That upon signing this document, it is understood that both I, and the individual or company I represent, grant our informed consent and, therefore, authorize the **BUYER** to communicate to the national authorities or to the authorities of any of the countries where the **BUYER** conducts operations about any of the situations described herein, as well as to furnish to the pertinent authorities of such countries every personal, public, private or semi-private information about myself or about the individual or company I represent, as required. Likewise, for the **BUYER** to issue the reports to the competent authorities deemed convenient, pursuant to their regulations and manuals related to the asset laundering and terrorism financing risk prevention and /or administration system, releasing it from any liability derived from the event.
- X. That every documentation and information furnished to enter into and execute the contract or legal business with the **BUYER** is true and accurate, being the **BUYER** empowered to make the verifications deemed convenient and to terminate the contract or legal business upon verifying or confirming otherwise.
- XI. That no other individual or company has an illegitimate interest on the contract or legal business that leads to the subscription of this statement.
- XII. That I know, declare and accept that the **BUYER** is legally obliged to request the clarifications deemed convenient in the event of circumstances where the **BUYER** can have reasonable doubts regarding my operations or the operations of the individual or company I represent, as well as the origin of our assets, case in which we undertake to provide the respective clarifications. If not satisfactory in the opinion of the **BUYER**, we authorize the termination of any commercial or legal business.

Based on the foregoing, the Parties,

AGREE

CLAUSE ONE. PURPOSE AND QUANTITIES: The **BUYER** undertakes to acquire up to one hundred percent (100%) of the crude owned by the **SELLER** produced in the Santana Shared Risk Contract (CPR-Santana), the Guayuyaco Association Contract and the Chaza E&P Contract owned by the **SELLER** and the latter, on its part, undertakes to sell and deliver up to one hundred percent (100%) of its crude produced in the aforementioned contracts. This Contract excludes the crude of volume derived from royalties.

For the purposes of this Contract, one barrel is equivalent to one hundred fifty eight thousand nine hundred and eighty-eight (158,988) liters.

PARAGRAPH ONE: CRUDE OIL DESTINATION The **BUYER** shall use the crude oil acquired at the Tumaco Station for the export, through the Tumaco port, the crude acquired in Orito, for the export through Ecuador, and the crude oil received at the Dina Station for the export through the Coveñas Port or for

Refining purposes. **The BUYER** may also: i) use the crude oil hereunder for the export through other ports and / or ii) for refining purposes by notifying the **SELLER** in writing.

PARAGRAPH TWO: The receipt of volumes to comply with the purpose of this Contract is subject to:

- i. The subscription of the respective transport contract through pipelines with the Vice-presidency of Transport and Logistics (VIT) of Ecopetrol S.A., or whoever acts as such.
- ii. The availability of receipt and transport facilities scheduled by the Vice-presidency of Transport and Logistics (VIT) of Ecopetrol S.A., or whoever acts as such.

CLAUSE TWO. PRICE: The price payable for the crude hereunder, placed at the Point(s) of Delivery set out in Clause Six herein shall be established as indicated below for the different components, part of the following formula(s):

A. For crude oil exported as Southblend through the Tumaco port and received at the Tumaco Plant:

Crude Oil Price = Indicator – Port Operation Rate – Marketability Rate

Below we define each of the foregoing terms:

Indicator: Corresponds to the average price of South Blend Crude exports in USD/bl made by the Foreign Trade Management of Ecopetrol S.A. (including crude oil negotiated on behalf of affiliates) in the month of deliveries through the Tumaco Port. This price shall be reported by the **BUYER**. Should no exports have been made in the delivery month, the parties shall apply the provisions set out in Paragraph One of Clause Three herein. The South Blend reference quality is 29.3° API and 0.62% Sulphur (S).

Port Operation Rate: Corresponds to a value of seven thousand sixteen ten-thousandth US dollars per barrel (US\$ / Bl 0,7016).

Marketability Rate: Corresponds to one dollar and fifty cents of a US Dollar per barrel (US\$ / Bl 1,50).

B. For crude exported as Eastern Crude through Ecuador:

Crude Oil Price = Indicator – Transport (Delivery Site /Shipping Port) – Transport Tax – Marketability Rate

Below we define each of the foregoing terms:

Indicator: Corresponds to the actual weighted average price of exports made by the **BUYER** of Eastern Crude in the month of deliveries or including crude oil shipped by the **BUYER** through the Balao port, associated with the deliveries. If during the delivery month, no exports are made through the Balao port, the price of the following export made, which includes crude oil owned by the **SELLER** shall be applied.

Transport (Delivery Site/ Shipping Port): Determined by adding the following rates:

Section	MME Resolution	Base100% MME Rate US\$/Bl
Orito – San Miguel (OSO)	124572	2,3472
La Ye - Orito (OMO)	124560	0,5387
Total Transport		2,8859

- Furthermore, the rate charged by PETROECUADOR for transporting crude between San Miguel and the port of Balao.

Transport Tax: Determined as provided for in Article 52 of the Colombian Petroleum Code for domestic systems set out in the prior section. For the Ecuadorian section, the respective tax, if applicable, shall be considered from the delivery site to the shipping port.

Section	MME Rate US\$/Bl	Transport Tax %	Transport Tax US\$/Bl
Orito – San Miguel (OSO)	2,3472	2%	0,0469
La Ye – Orito (OMO)	0,5387	2%	0,0108
Total Tax			0,0577

Marketability Rate: Corresponds to one dollar and fifty cents of a US Dollar per barrel (US\$ / Bl 1,50).

C. For the crude delivered to the Dina Station for export through the Coveñas port or for refining purposes:

Crude Oil Price = Indicator – Transport (Delivery Site /Shipping Port) – Transport Tax – Marketability Rate - Port Operation Rate

Below we define each of the foregoing terms:

Indicator: Corresponds to the average export price of the Crude Corporate Group in the Vasconia export blend through the Coveñas Port, negotiated in the crude oil delivery month. This price shall be reported by the **BUYER**. The Vasconia export blend Crude reference quality is 24.8° API and 0.97 % Sulphur (S). In the event that Ecopetrol's Corporate Group fails to make the exports in the delivery month, the indicator shall correspond to the Vasconia Crude export average reported by Argus & Platts for the delivery month. This value shall be reported every month by the **BUYER**.

Transport (Delivery Site/ Shipping Port): Determined as the sum of the rates set out by the Ministry of Mines and Energy for the pipeline between Tenay and Coveñas. Pipeline transport rates shall be adjusted each year through the "Phi" Factor, as provided for by the Ministry of Mines and Energy. The rates applicable in 2012 are:

Section	Sanctioning Resolution	Base100% MME Rate US\$/BI
Tenay –Vasconia	OAM	2,6035
Vasconia – Coveñas ODC	ODC	1,7053
Total Transport		4,3088

Transport Tax: Determined as provided for in Article 52 of the Colombian Petroleum Code (or the norm that amends it) for domestic systems set out in the prior section, based on the following details:

Section	MME Rate US\$/BI	Transport Tax %	Transport Tax US\$/BI
Tenay –Vasconia	2,6035	2%	0,0521
Vasconia – Coveñas ODC	1,7053	2%	0,0341
Total Tax	4,3088		0,0862

Marketability Rate: Corresponds to one dollar and fifty cents of a US Dollar per barrel (US\$ / BI 1,50).

Port Operation Rate: Corresponds to a value of six thousand one hundred and ten ten-thousandth US dollars per barrel (US\$ / BI 0,6110).

PARAGRAPH ONE: The price determined through the aforementioned formula includes the different transport, handling, metering and transport tax costs payable by the **SELLER**, accrued up to the delivery of crude oil hereunder at the Points of Delivery; therefore, the **BUYER** shall make no further payments for the aforementioned concepts.

PARAGRAPH TWO: When the Parties agree Points of Delivery other than those set out in Clause Six, the price formula provided for in this Clause shall be amended in the transport item, taking into account

the crude transport rates and taxes via pipeline in force between the Point of Delivery and the applicable export port. Likewise, the indicator shall be modified, as applicable, prior agreement between the parties.

PARAGRAPH THREE: Receipt and metering costs, in the case of stations agreed by the Parties, and which are not operated by **ECOPETROL S.A.** shall be directly paid by the **SELLER** to the respective operating company. **The BUYER** shall make no additional payments whatsoever for such concepts. The Unloading rate value at the Dina Station corresponds to the value charged by the Vice-Presidency of Production or the corresponding area, as agreed in the Unloading contract.

PARAGRAPH FOUR: PRICE RENEGOTIATION. Any of the Parties may request a review of the prices set out herein, provided any of the following events takes place:

- a) A change of nearly two (2) API grades in the quality of crude oil produced on the field / area / block / contract.
- b) A change of nearly two (2) API grades in the quality of the Indicator Crude during three (3) consecutive months. In this case, the review request must be made during the month following the period of three (3) consecutive months.
- c) In case that the Indicator Crude disappears and a new Indicator is to be defined.

The Parties shall have a thirty (30) business day-term to negotiate. Should an agreement be reached, evidence thereof shall be recorded by signing an amendment by the **BUYER** and the **SELLER** and the provisions therein shall apply as of the day following the date in which such amendment is signed.

If at the end of the thirty (30) business-day term, no agreement is reached, the **BUYER** or the **SELLER** may notify the other party its intent to terminate the Contract, as provided for in Clause Twenty One of this Contract.

The termination shall not release the Parties from complying with the obligations already accrued.

PARAGRAPH FIVE: QUALITY SPECIFICATIONS. The quality of crude received shall be guaranteed by the Seller up to the Point of Delivery; however, it shall be verified by the **BUYER** at the Point of Delivery set out in Clause Six and shall comply with the following quality specifications:

Field	° API Minimum	SULPHUR (% weight) Maximum	BSW (% in volume) Maximum	SAL (Lb/1000Bl) Maximum
Santana and Guayuyaco	25,0°	0,70	0,50	20,0
Chaza	29,0°	0,41	0,50	20,0

- Crude density shall be determined through the ASTM-D-1298 Lab method (Method to determine density, specific density (specific gravity) or API Gravity of crude and liquid oil products through the Hydrometer method).
 - The water and sediment content, BSW, shall be determined through the methods:
Suspended water ASTM-D4377 “Standard Test Method for Water in Crude Oils by Potentiometric Karl Fischer Titration and ASTM-D473 Sediments” and “Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method”. For the water and sediment content in crude, the following shall be accepted as maximum individual values: 0.50% water volume and 0.01% sediment volume.
 - The sulphur content shall be determined through method ASTM-D4294 “Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy Dispersive X-ray Fluorescence Spectrometry”.
 - The salt content shall be determined through ASTM-D3230 "Standard Test Method for Salts in Crude Oil through Electrometric Method".
- When the BSW, Salt and Sulfur specifications herein established are not within the margin allowed, the **BUYER** reserves its right to receive crude oil and to buy them at a BSW and Salt-adjusted price. In these cases, the crude price shall be adjusted, based on the following tables:

BSW Content % Volume	Correction(US\$/Barrel)	In charge of
0.51 to 0.80	0,10	THE SELLER
0.81 to 1.00	0,20	THE SELLER
1.01 to 1.20	0,30	THE SELLER
1.21 to 1.50	0,40	THE SELLER
>a 1,51	Not received	
Salt Content Pounds for every thousand Barrels	Correction (US\$/Barrel)	In charge of
20.1 to 30.0	160	THE SELLER
30.1 to 40.0	180	THE SELLER
40.1 to 60.0	200	THE SELLER
60.1 to 80.0	220	THE SELLER
80.1 to 100.0	240	THE SELLER
>a 100.0	Not received	

It is understood that the **SELLER** shall make sure it delivers the crude oil hereunder with the BSW and Salt content within the parameters agreed. These corrections shall be applied to daily deliveries or to each batch delivered.

In case that crude deliveries exceed the maximum values set out in the table (1.51 BSW and 100.0 lbs of salt for every thousand barrels) and if the **BUYER** decides to receive the crude, the Parties shall agree the value of the corresponding correction and evidence thereof shall be included in an Amendment signed by the parties. Should no agreement be reached, the **BUYER** may reject the crude.

PARAGRAPH SIX: Reimbursable expenses: Reimbursable expenses may not exceed forty million pesos (COP 40,000,000), VAT excluded per year, and shall be previously authorized and approved by the **BUYER**. In this case, the cost of the independent inspector shall be solely and exclusively paid, as referred to in Paragraph Two of Clause Five herein.

The amount of the reimbursable expenses shall not be part of the Contract value. The management of reimbursable expenditures shall be made in accordance with the procedures in force implemented by the **BUYER** for this type of expenditures (annex 3).

CLAUSE THREE. INVOICING AND PAYMENT: The **SELLER** shall invoice and collect from the **BUYER** the cost of the crude sold, as provided for herein, in his Accounts Payable offices in Bogotá, within the first ten (10) business days of the month following the crude delivery(ies) to the **BUYER**. Within the first six (6) business days of the month following the deliveries, the **BUYER** shall provide to the **SELLER** the information it requires to issue the corresponding invoice. Invoices must be filed at the Accounts Payable offices of the **BUYER** in Bogotá and its valid submittal date for payment shall be that set out as receipt at the Accounts Payable office of the **BUYER** in Bogota. Invoicing shall be made based on net volumes, water and sediment-free, corrected at sixty (60) Fahrenheit degrees, received at the Point(s) of Delivery. For invoice approval, they must be submitted in the official forms of Chart No. 4 and/or Form No. 9SH of the Ministry of Mines and Energy. In the event that the Ministry of Mines and Energy fails to deliver the signed Charts No. 4 and /or Form No. 9SH corresponding to the month being invoiced, Charts No. 4 and / or Form No. 9SH submitted to the Ministry of Mines and Energy pending signature shall be temporarily accepted, but every quarter, the **VENDOR** shall submit to the **BUYER** a copy of Charts No. 4 and /or Form No. 9SH of the immediately previous quarter, duly completed and signed by the Ministry of Mines and Energy.

Taking into account the foreign currency payment authorization set out in Article 51 of External Resolution No. 8 of 2000 of the Board of Directors of the Central Bank, which provides that domestically-produced crude oil and natural gas purchase-sales made by the **BUYER** and other entities devoted to the oil refining industrial activity can be paid in foreign currency, the invoicing that the **SELLER** issues for the supply of crude to the **BUYER** may be made in dollars of the United States of America.

In every case, payment shall be made 100% in dollars and shall be made thirty (30) calendar days following the submittal of invoices duly completed, prior legal withholdings, if applicable. **The SELLER** shall notify the **BUYER** in advance and in writing the bank account where the respective payment is to be made.

PARAGRAPH ONE: Invoicing for deliveries to the Port of Tumaco: Crude deliveries shall be invoiced in accordance with the volumes and prices notified by the Ecopetrol S.A. Crude Procurement Coordination during the first six (6) business days following the end of the delivery month; such volumes shall be subsequently adjusted based on the compensated volumes of the official volumetric offset compensation prepared by the Vice-Presidency of Transport and Logistics of Ecopetrol or whoever acts as such.

Once the volumetric compensation is received, the **SELLER** shall be responsible for invoicing and filing at the Accounts Payable office of the **BUYER** the respective adjustments within the three (3) business days following the receipt of the volumetric compensation, taking into account the receipt dates at Ecopetrol's Accounts Payable offices.

For those months where South Blend exports are not made through the Tumaco Port, the price to be used shall correspond to the weighted average of the volume reported in the commercial meter corresponding to the last month in which South Blend exports had been made, or the blend exported through the port of Tumaco; such price shall be adjusted to the average price weighted by export volume of the South Blend or the blend exported through the Port of Tumaco in the month of deliveries or, if no exports were made in the month of deliveries, with the price for the following month in which exports are carried out.

Based on the conditions set out herein, no payments corresponding to volumes not received at the Tumaco plant shall be made.

PARAGRAPH TWO. For deliveries to the Orito Station for export through Ecuador: In the event that by the date to invoice the export crude through the Balao port, no final export price, volumes exported or rates collected by Petroecuador in formation is available, invoicing shall proceed in accordance with the crude volume shipped from the Orito Station, prorated by the volumes delivered by each operator. The price to be used shall correspond to the arithmetical average of the daily quotes of Eastern crude reported by the Platt's Agency shall be used, during the days in which crude was pumped to Lago Agrio.

Invoicing shall be adjusted once final information of volumes and prices of the East Blend crude exported by Petroecuador with volumes pumped from Colombia is available, notifying the presence of crude oil delivered by the **SELLER**.

Once the information of East Crude exports made through the Balao Port with crude volumes from Colombia, and specifically hereunder is received, the **SELLER** shall be responsible for invoicing and submitted to the accounts payable office of the **BUYER** the respective adjustments within the following three (3) business

days after the respective information is received, taking into account the accounts payable receipt dates Ecopetrol.

PARAGRAPH THREE: The **BUYER** shall have a term of ten (10) business days, counted as of the receipt of the crude sales invoices to review them or object them. Should invoices be questioned, the receipt date shall be that of the filing of the new invoice. The **BUYER** shall notify the **SELLER** within the term foreseen about any invoice questioned, for it to be adjusted and corrected, by clearly indicating the items to be adjusted or corrected and the corresponding reasons thereof. The **SELLER** shall respond to the objection within ten (10) business days following the receipt thereof, counted as of the time in which the **BUYER** submits to the **BUYER** all the documents that gave rise to the objection, unless the Parties determine by common consent to extend the term if the objection complexity or if any reasonable circumstance so requires.

In the event that the **SELLER** fails to respond to the objection within the aforementioned term the objection shall be considered accepted by the **SELLER**. Should the **SELLER** resolve the objection in favor of the **BUYER**, it shall be understood that there was no payment obligation over the invoice originally filed, subjected to objection. Should the **SELLER** resolve the objection in its favor, the **BUYER** shall endeavour to solve the dispute forthwith, based on the provisions of this contract, in order to make the payment of the unpaid amount. To solve any discrepancy, each of the Parties shall submit to the other a copy of the documents that gave rise to the invoice and to the objection. In the event that the **BUYER** disagrees with the decision of the **SELLER**, it may apply the provisions set out in Clause Seventeen of the Contract.

PARAGRAPH FOUR: In the event of unjustified delay on the payment of invoices not objected in due time by the **BUYER**, as foreseen in Paragraph Three herein, the **BUYER** shall pay to the **SELLER**, as interest rate payable in pesos, the maximum arrears interest rate authorized by the Financial Superintendence during the arrears days effectively elapsed.

For purposes of calculating late interests, the amount of dollar invoice(s) in arrears shall be converted first into Colombian pesos, at the market representative exchange rate in force on the date of issuance, as certified by the Financial Superintendence of Colombia.

Invoices for interest collection shall be paid by the **BUYER** thirty (30) calendar days following the receipt thereof by the **BUYER**.

Both the **BUYER** and the **SELLER** understand that invoices issued, as well as this Contract shall give right of execution and the **BUYER** and **SELLER** expressly waive to the private or legal requisites to be declared in arrears.

PARAGRAPH FIVE: In case that the **SELLER** becomes interested in doing factoring with the invoices issued with respect to this Contract, it shall first offer the option to the **BUYER**.

CLAUSE FOUR. CONTRACT TERM: The Contract term shall begin with its formalization and shall include the execution and liquidation term.

The Contract execution term shall begin upon signing this document and shall end on November 30, 2013.

Within a term of four (4) months counted as of the date of Contract Execution term ending, the parties shall sign the respective liquidation minutes.

In the event that the **SELLER** fails to attend to the liquidation or if no agreement is reached on the contents thereof within the aforementioned term, it shall expressly empower the **BUYER** to proceed with the unilateral liquidation within two (2) months.

CLAUSE FIVE. INSPECTION AND METERING. The quantity and quality shall be measured at the Point(s) of Delivery defined in Clause Six, and shall be made following the operative procedures, instructions, recommendations and methods set out in the Hydrocarbons Metering Manual of **ECOPETROL S.A.**, (hereinafter the "MMH"), attached hereto as Annex 4. In the event of amendments, additions or deletions to the MMH, the **BUYER** shall notify the **SELLER** of such changes, which shall be mandatory upon notice. Quantity and quality metering shall be made by qualified personnel. The stations and / or dependencies of the **BUYER** and/or associates where crude is received shall certify the volume and quality (API, BSW and SAL) of the crude received every day therein. In case of deliveries at Tumaco, volumes and quality are determined through volumetric compensation.

PARAGRAPH ONE: QUANTITY METERING. The volume shall be calculated as the Net Standard Volume (NSV) and shall be understood as the total volume of all oil liquids, excluding sediment and water (BSW) at a standard temperature of 60° F. Metering can be made through static or dynamic metering, applying the methods described in the MMH. The volume used to calculate the crude delivered by the **SELLER** at the inlet flange at the Tumaco Plant shall be the volume resulting after the application of the volumetric compensation and sent by the Transport and Logistics Vice-Presidency. For crude delivered at the inlet Flange to the Orito Station tanks for crude exported as Eastern Crude through Ecuador and for crude delivered at the Dina Station, it shall be made in accordance with the invoicing and payment Clause.

PARAGRAPH TWO: QUALITY METERING. Quality metering shall allow determining the actual characteristics of crude hereunder. In determining the above, a representative sample of the total volume shall be available, as described in MMH, Chapters 8, 9, 10 and 14, and shall serve to establish the deviations that may affect hydrocarbon price.

The crude sulphur content for invoicing purposes shall be that reported by the Colombian Oil Institute (ICP), based on the semester analyses made for each crude. **The BUYER** shall update this information every six months and shall deliver it to the **SELLER**. In the event that the sulfur content analysis made by ICP is not available, the sulfur content shall be, for invoicing purposes, that set out in Paragraph Five of Clause Two

of this document, which shall be in force until the ICP makes a new analysis and it is reported to the **SELLER** by the **BUYER**. As of the day following the receipt of the information analysis made by the ICP by the **SELLER**, the crude sulfur content for invoicing purposes shall be that set out by the **BUYER** in such report. Any of the Parties, when deemed convenient, can request a new sulfur content analysis by the ICP.

Any of the Parties may designate, as required, an independent inspector to certify the quality and quantity, verify the capacity of tanks or the calibration of the volume metering instruments. The cost of the analyses or inspections shall be equally shared by the **BUYER** and the **SELLER**.

The SELLER shall be responsible for paying the fees of the external inspector. **The BUYER** shall pay to the **SELLER** half of its share of the invoices issued by the external inspector as a reimbursable expenditure, as per Paragraph Six of Clause Two.

CLAUSE SIX. POINTS OF DELIVERY: **The BUYER** and the **SELLER** agree that the Point(s) of Delivery and transfer of crude ownership hereunder shall be: i) Inlet flange to the main tanks at the Tumaco Plant for crude exported as South Blend, ii) Inlet flange to the Orito Station tanks for crude exported as Eastern Crude through Ecuador and iii) Unloading line flange of tanker trucks at the Dina Station for crude bought for export through the Coveñas port or for refining purposes. At all of these points, delivery shall be made by metering tanks and/or with a flow meter, following the procedures set out in Clause Five of this document.

The SELLER transfers to the **BUYER** the ownership over the Crude at the Point(s) of Delivery. **The SELLER** guarantees that upon delivery, crude shall be free of any lien or economic burdens by any government entity of any level or natural person or corporation, for any concept including, among others, those derived from taxes, rates, contributions, shares or royalties, encumbrance or any legal or out-of-court measure that may restrict or limit the use or disposal of crude by the **BUYER**. The costs related to the transport of crude to the Point(s) of Delivery as well as the costs associated with crude delivery shall be paid by the **SELLER**.

PARAGRAPH ONE: Any of the Parties may propose the change or addition of a Point of Delivery; in such case, the Parties, by mutual consent, shall define the new Point(s) of Delivery and the conditions governing over them through an amendment to be signed by the legal representatives of the Parties.

PARAGRAPH TWO: The volumes to be received at each of the stations defined in this clause shall be established on a monthly basis, based on the official transport schedule established by the **BUYER**.

CLAUSE SEVEN. DELIVERY SCHEDULE: For deliveries at the inlet flange of the Tumaco Plant tanks for crude exported as South Blend, the parties acknowledge and accept that the delivery program provided for by virtue of this Contract is subjected to the commitments agreed in the transport contract, which includes the Operation and Transport Regulation signed by the **SELLER** and the **VICE-PRESIDENCY OF TRANSPORT AND LOGISTICS OF ECOPETROL S.A.** Consequently, the **SELLER** shall nominate

crude to be transported and delivered, pursuant to the terms and conditions defined in Clause 8 of the Ecopetrol Pipeline Transporter Manual. Likewise, the volumes to be received by the **BUYER** shall be those approved by the **TRANSPORTER**, pursuant to Clause 8, Number 8.4.1 of the Ecopetrol Pipeline Transporter Manual.

In the event of a force majeure case, the delivery schedule shall be redefined. This new schedule shall be agreed between the **BUYER** and the **SELLER**.

It is the **SELLER's** obligation to furnish and maintain field information on the production, calculation of royalties, shipments through tanker trucks and / or pipelines, indicating share and ownership of each one and the official receipt at the receipt station. To such end, it shall submit on a daily basis to the **BUYER** the information requested through the volumetric integrator of the **BUYER** available through the Web page, for which the User Manual is attached as Annex 5.

It is the **SELLER's** obligation to complete the respective transport document (as applicable), indicating fields and volumes dispatched on each tanker truck and describing on the "Observations" field that the crude corresponds to a sale to Ecopetrol S.A.

In the event that within the term agreed, the **BUYER** cannot receive all the crude at the Point(s) of Delivery, it shall so notify it to the **SELLER** minimum three (3) calendar days in advance and as soon as the contingency is solved, it shall announce the date to reactivate receipts.

Likewise, in the event that for reasons inherent to the field operation, the **SELLER** cannot deliver to the **BUYER** the crude in any of the dates determined in the schedule, it shall notify the **BUYER** in writing three (3) calendar days prior to the respective delivery date and as soon as the contingency is solved, it shall announce the date to reactivate deliveries.

Should a place other than that set out for crude receipt is indicated, the parties shall make the adjustments established in the transport item and in the transport tax, in the formulas defined in Clause Two of this document, pursuant to the highest or lowest value required for transport to the new Point(s) of Delivery defined by the **BUYER**, considering for the purpose the transport rates in force when the situation takes place. All of the above shall be evidenced in minutes or amendment, which shall be signed by the Parties for the purpose.

CLAUSE EIGHT. SAFETY - HSE: It is a special obligation of the **SELLER** to have a hygiene, safety and occupational health program for the Crude transport operation to the Point(s) of Delivery.

CLAUSE NINE. CONTRACT ADMINISTRATION AND MANAGEMENT: The Authorized Official of **ECOPETROL S.A.** shall designate the Contract administration and management; those assigned with such responsibility shall have the powers and obligations foreseen in the Guideline for Contract and / or

Agreement Administration and Management of **ECOPETROL S.A.**, which is incorporated hereto as Annex 6.

The BUYER shall evaluate vendor's performance as Contractor at the end of the Contract, pursuant to the "Contractor Performance Evaluation" guideline, which shall be furnished by the **CONTRACTOR** to the **SELLER** once the Contract is formalized.

CLAUSE TEN. ASSIGNMENT: **The SELLER** may not assign, sell or transfer all or part of its rights and obligations herein contracted to a third party, without the prior, written consent of the **BUYER**.

CLAUSE ELEVEN. FORFEITURE: **The BUYER** shall terminate the Contract and order its liquidation, regardless of the status, when the **SELLER** incurs in the conducts forbidden in article 25 of Law 40 of 1993 (payment of sums of money to extortionists or hide or cooperate by any executive or delegate of the **SELLER** in the payment for the release of a kidnapped person, who is an official or employee of the **SELLER** or any of its affiliates).

If forfeiture is declared, there shall be no grounds to pay indemnification to the **VENDOR**, who shall become responsible for the sanctions and inabilities foreseen in the Law. The forfeiture declaration shall constitute grounds for default. **ECOPETROL S.A.** shall declare forfeiture through grounded resolution that will be notified in due time to the **SELLER**, who may file any legal remedies. **The SELLER** shall be entitled, prior deductions applicable pursuant to the clauses of this Contract, to receive payment for the part of the goods or services received at satisfaction by the **BUYER** up to the date of the forfeiture declaration.

CLAUSE TWELVE. FORCE MAJEURE, ACT OF GOD AND THIRD PARTY EVENTS: The obligations of any of the Parties derived herefrom, which may not be fulfilled due to Force Majeure, Act of God or Third Party Event, total or partial, shall be suspended during the time the effects thereof last.

The party invoking the occurrence of a Force Majeure, Act of God or Third Party Event shall notify the other Party about such situation, including commencement date and time, immediately over the phone and in writing on the business day following the occurrence of the event, submitting the evidence that prove the occurrence thereof. The Party notified about the Force Majeure, Act of God or Third Party Event may request the submittal of additional information to support the declaration, and the affected party shall submit it within five (5) business days following the request thereof. Should there be differences between the Parties as to the event set-up, the parties shall proceed in accordance with the dispute settlement mechanisms foreseen in Clause Sixteen herein.

The Party invoking the occurrence of a Force Majeure, Act of God or Third Party event shall endeavour to correct the cause that led to the declaration thereof, and shall notify the other Party about the date and time in which such event was resolved.

For the purposes of this Contract, Force Majeure or Act of God event is every event that may be classified as such according to the Applicable Law, whether unforeseen and irresistible, duly proven, and provided it is beyond the reach of the Parties and if it takes place without their fault or negligence.

Force Majeure or Act of God events include, among others, the following acts or events: a) Epidemic outbreak, landslides, hurricanes, floods, avalanches, lightning, earthquakes, tidal waves, shipwreck, disaster during ground, air, railway, river and sea transportation, which directly or indirectly contribute or result in any of the Party's impossibility to fulfill its obligations. b) Acts or lack of acts by the Government and the Legislative and Judicial branches of it, including laws, orders, regulations, decrees, rulings, judicial actions, regulations, issuance denial, renewal or confirmation of permits and licenses made by the Government or the competent authority having jurisdiction over the production, treatment, collection, transport, distribution and purchase-sale of crude and / or product activities, and which directly or indirectly contribute to, or result in the failure by any of the Parties to meet its obligations, or which seriously or unfairly affect the interests of any of the Parties, or seriously affect their financial capacity. c) Civil riots, including war, blockages, insurrection, massive protests and serious threat of any of the above, fully demonstrated, and actions of military forces related to, or in response to any act of civil upset, which directly or indirectly contribute or result in the Parties' failure to comply with their obligations.

Third Party events include: a) Total or partial impossibility to operate and manage the facilities and installations for the production, management, transport, delivery or receipt of crude and / or products, and of the pipelines, tanker trucks, vessels or any other means used for the transportation thereof, as well as the connections or the facilities of any of the Parties, due to willful acts of third parties beyond the control and direct management of the **SELLER** or the **BUYER** without their fault, such as terrorist or guerrilla attacks or sabotage or the serious public order upset, among others, which directly or indirectly contribute or result in, or lead to any of the Party's failure to comply with its obligations, b) Emergency shutdown at the facilities of the **SELLER** or the **BUYER** c) Industrial riots including the illegal suspension of activities and strikes when these acts contribute to affecting the **BUYER's** ability to comply with their obligations and d) Industrial upset acts, including activity suspension, strikes and blockages, when these acts contribute to, or result in the **SELLER's** inability to meet its obligations.

PARAGRAPH ONE: In no case shall the financial condition changes of the **BUYER** or the **SELLER** constitute a Third Party Event hereunder.

Neither the **BUYER** nor the **SELLER** shall be liable for the default or partial default of each and every obligation hereunder, if such default is caused by events that constitute Force Majeure, Act of God or Third Party events duly proven.

The Force Majeure, Act of God and/or Third Party events shall not release the **BUYER** from its obligation to pay to the **SELLER** those invoices for the sale of crude delivered by **SELLER**, in accordance with the terms set out in this CONTRACT.

The occurrence of any of the events foreseen herein shall not release or prevent, in any case, the Parties from complying with their obligations acquired and / or accrued prior to the occurrence of the events referred to in this clause.

CLAUSE THIRTEEN. COLOMBIAN LAW ENFORCEMENT: This Contract is governed by the Colombian laws.

CLAUSE FOURTEEN. TAXES: Each of the parties in this purchase-sale declares to know and accept the taxes and/or withholdings applicable, pursuant to the Laws in force. The payment of all national, departmental and municipal taxes, liens, rates, contributions, quotas or similar, accrued or to be accrued hereunder including, without limitation, those incurred in due to the entering into, formalization, execution and termination or liquidation of this Contract, or which may arise after the execution of this Contract shall be paid by the respective taxpayer, who shall pay them in accordance with the laws and regulations in force.

CLAUSE FIFTEEN. FORMALIZATION: This Contract is formalized upon the execution thereof. For publication purposes, strict compliance of the provisions of Ecopetrol in this regard, foreseen in the Contracting Manual.

CLAUSE SIXTEEN. CONFLICT RESOLUTION: In case of differences, conflicts or disputes related to the interpretation, execution and enforcement of this contract, the Parties shall refer to the alternate conflict resolution mechanisms legally regulated.

CLAUSE SEVENTEEN. SPANISH LANGUAGE: This Contract shall be written in Spanish and constitutes the sole form of obligations between the Parties. Any translation to another language shall be considered a reference for the Parties, and in no case shall this affect the meaning or interpretation of the Spanish version.

CLAUSE EIGHTEEN. CONTRACT VALUE: The Contract value is undetermined.

CLAUSE NINETEEN. INFORMATION CONFIDENTIALITY: For the purposes herein, the Party that communicates or discloses information shall be hereinafter referred to as the Disclosing Party and the party that receives the information shall be hereinafter referred to as the Receiving Party. The Parties agree that all technical, commercial, industrial or financial information furnished, exchanged and / or prepared by the Parties in furtherance of this Contract, or developed, received or obtained by any of the Parties with respect to this Contract (hereinafter the "Confidential Information" or the "Information") shall be subjected to strict reserve and confidentiality during the Contract term, and for three (3) years following the date of termination thereof.

For the purposes of this Contract, Confidential Information is: (i) is of public domain upon disclosure or becomes known after the disclosure thereof, through different acts or omissions by the Receiving Party; (ii) is known by the Receiving Party before, upon it is received or obtained hereunder, without such knowledge being derived from the breach of a confidentiality obligation, (iii) is developed by the Receiving Party independently, or based on the information or documentation received from a third party, without the latter being considered, in turn, a breach of a confidentiality obligation; (iv) is received or obtained, in good faith, by the Receiving Party, from a third party, without this implying, in turn, a breach of a confidentiality obligation; (v) its dissemination and/or disclosure is required by the Receiving Party in furtherance of the legislation in force, legal provision, firm administrative act, competent legal and / or government authority with jurisdiction over the Parties or their affiliates, or by norms of any Stock Exchange, where the actions of the Parties or corporations related are registered, under the terms and to the extent required..

The Receiving Party may disclose the Confidential Information to its management, officials, employees, executives, agents, partners, representatives or associates, affiliates and subordinates (generically denominated Representatives).

It is requested or demanded by a judicial or administrative authority that the Receiving Party, by virtue of the law, regulation or judicial resolution, furnish any part of the Information; such Receiving Party may request cooperation of the Disclosing Party and, if convenient, shall enquire with it the measures to be taken to maintain confidentiality.

CLAUSE TWENTY. SPECIAL OBLIGATIONS OF THE SELLER RELATED TO THE PREVENTION AND CONTROL OF ASSET LAUNDERING AND TERRORISM FINANCING (LA/FT)

- a. To fully comply with the legal provisions on asset laundering prevention and control and terrorism financing (LA/FT) applicable by efficiently and timely implementing the policies and procedures needed for the purpose.
- b. To abstain from carrying out operations with persons or entities whose funds are derived from the illegal activities set out in the Penal Colombian Code or in any norm that replaces it, adds to it or amends it, or on those having grounded concerns about the origin of the resources, based on public information.
- c. To respect and adhere to the Good Governance Code, the Integral Responsibility Policies and the Corporate Social Responsibility Policy of Ecopetrol, the Code of Ethics and the policies to prevent, control and administer the asset laundering risk and terrorism financing (LA/FT) of the **BUYER**. For such purposes, the **SELLER** declares to know such documents.
- d. In such cases where activities are carried out, which are considered high LA/FT risk, it undertakes to adopt LA/FT prevention systems.

- e. To abstain from using its operations as instrument to conceal, manage, invest or utilize, in any way, cash or other goods derived from criminal activities or to try to convey legality in the transactions and funds related therewith, or aimed at carrying out illegal activities.
- f. To report to the **BUYER** (Telephones 018000917045 – (57-1-2343345 – 57-1-2344092) and to denounce to the competent authorities the crimes it becomes aware of (corruption, extortion, document forgery, asset laundering, terrorism financing and others), as provided for in Article 67 of the Criminal Procedure Code (Law 906 of 2004 and those that add to it or replace it).
- g. To report to the **BUYER** the incidents or events that may affect its image or reputation and / or that of the **BUYER** within three (3) business days following the occurrence thereof, in order to adequately manage them.
- h. To timely respond to the information requirements and clarifications requested by the **BUYER** in furtherance of this contract.

CLAUSE TWENTY ONE. EARLY TERMINATION:

21.1 The **SELLER** or the **BUYER** may terminate, at any time, this Purchase - Sale Contract, without it being obliged to indemnify for any type of prejudice to the other party, provided the party wishing to terminate the Contract in advance submits to the other a written communication within thirty (30) calendar days in advance to the date in which the Contract is to be terminated.

21.2. Likewise, those events related to asset laundering prevention and control and terrorism financing shall be considered grounds for early contract termination without this implying indemnification in favor of the **SELLER**, as well as the following:

1. When **the SELLER** fails to comply with the legal provisions related to asset laundering prevention and control and terrorism financing, as applicable.
2. When **the SELLER** or any of its shareholders, associates or partners who directly or indirectly own FIVE PERCENT (5%) or more of the stock capital, contribution or share, are included in the international lists which are binding for Colombia, pursuant to the international law (UN lists) or in the OFAC lists.
3. When the **SELLER** or its shareholders, associates or partners, having directly or indirectly FIVE PERCENT (5%) or more of the stock capital, contribution or share, its legal representatives and members of the Board of Directors are involved in investigations or criminal processes for willful acts, or if there is public information about such persons, which may expose the **BUYER** to a legal or reputation risk.

4. When situations take place, which may represent to the **BUYER** reputation, legal, operative or contagious risks related to asset laundering and / or terrorism financing.
5. When situations take place, which lead to founded concerns about the legality of the operations of the **SELLER**, the legal nature of the funds or if the **SELLER** has carried out transactions or operations aimed at such activities or in favor of persons related therewith.
6. When mistakes, inconsistencies, discrepancies or forgeries take place in the documentation and information furnished by the **SELLER** in entering into and executing this contract.

21.3 Likewise the **BUYER** may terminate the contractual relation when the **SELLER** incurs in any of the following conducts:

1. Unjustifiably give way to threats proffered by outlawed groups.
2. Receive, supply, administer, invest, finance, transfer, keep, transport, store or preserve monies or goods derived from, or targeted to such groups, and to provide support to such groups.
3. Build, assign, lease, make available, facilitate or transfer under any title goods to be used to conceal persons or to store or keep the belongings of such groups.
4. Paralyze, suspend or significantly reduce the compliance of its contractual obligations to follow the instructions of such groups.
5. Failing to denounce criminal events, the commission of which is imputable to such groups, known in furtherance of the Contract.

For the purposes of the above, the conduct of agents or dependents known to the Seller constitute an event imputable to it.

CLAUSE TWENTY TWO. NOTICES: All notices, requests, communications or notices that the Parties must exchange by virtue of this Contract shall be made in writing and shall be considered served upon the document's presentation at the address set out herein below.

THE BUYER

ECOPETROL S.A.
Planning and Supply Management
Bernardo Castro Castro
Carrera 7 No. 37-69 Piso 7, Bogotá D.C.
Telephone (+57) 1 234 4606
Fax (+57) 1 234 4869

THE SELLER

GRAN TIERRA ENERGY COLOMBIA LTD.
 Carlos Felipe Marín / Juan Carlos Buitrago
 Commercial Management
 Calle 113 No. 7-80, piso 17
 Telephone (+57) 6585757
 Fax (+57) 2139327

Communications sent by fax shall be deemed served once the successful communication message from the machine where the communication is submitted is received.

CLAUSE TWENTY THREE. DOMICILE: For all legal purposes, the contractual domicile is established in the city of Bogota, D.C.

In witness whereof, this document is signed in Bogotá D.C. on December 1st, 2012, in two identical counterparts.

THE SELLER	THE BUYER
<p style="text-align: center;"><u>/s/ Duncan Nightingale</u></p> <p style="text-align: center;">DUNCAN NIGHTINGALE Legal Representative</p> <p style="text-align: center;"><u>/s/ Alejandra Escobar Herrera</u></p> <p style="text-align: center;">ALEJANDRA ESCOBAR HERRERA Legal Representative</p>	<p style="text-align: center;"><u>/s/ Bernardo Castro Castro</u></p> <p style="text-align: center;">BERNARDO CASTRO CASTRO Planning and Supply Management</p>

CONTRACT: VSM-GPS-053-2012

PURPOSE: PURCHASE - SALE OF CRUDE CHAZA and GUAYUYACO

SELLER: PETROLIFERA PETROLEUM (COLOMBIA) LIMITED

VALUE: UNDETERMINED

The contracting parties, namely: **ECOPETROL S.A.**, national decentralized entity, created through Law 165 of 1948, with TIN 899.999.068-1, organized as Mixed Economy Corporation, based on the provisions of Article 2 of Law 1118 of 2006, ascribed to the Ministry of Mines and Energy, with main domicile in Bogotá D.C., which By-Laws are integrally contained in Public Deed No. 5314 of December 14, 2007, issued at Notary Public Office Two of the Bogota D.C. Notary Circle and registered at the Chamber of Commerce of Bogota D.C., which shall hereinafter for all purposes be referred to as the **BUYER**, represented herein by **BERNARDO CASTRO CASTRO** of age, and resident of this city, identified with Colombian Identity Card No. 79.295.921 issued in Bogotá, who in his condition of **Planning and Supply Manager** and in furtherance of the authorization contained in the Authority Delegations Manual of ECOPEPETROL S.A. acts on behalf of, and in representation of this Company and, on the other, **PETROLIFERA PETROLEUM (COLOMBIA) LIMITED**, with TIN 900.139.306-1, hereinafter the **SELLER** and jointly represented herein by **DUNCAN NIGHTINGALE**, identified with passport No. BA286341, acting in his capacity of Legal Representative and **ALEJANDRA ESCOBAR HERRERA**, identified with Colombian Identity Card No. 52.646.943 who acts in her capacity of Legal Representative and are duly authorized to enter into this Contract, as evidenced in the Certificate of Good Standing attached hereto, and who have stated that neither of them, or the company they represent are involved in any grounds for inability or incompatibility foreseen in the Political Constitution or in the Law, which may prevent them from entering into this Agreement.

In the foregoing conditions, **the BUYER** and the **SELLER**, who shall jointly be referred to as the Parties and individually the Party, agree to subscribe to this Contract, prior the following:

CONSIDERATIONS AND REPRESENTATIONS

1. That on June 27, 2005, the **Agencia Nacional de Hidrocarburos (ANH)** and the **SELLER** entered into a Hydrocarbon Exploration and Production Contract denominated Chaza.

2. That on September 30, 2002, **ECOPETROL S.A.** and **the SELLER** entered into an Association Contract denominated Guayuyaco.
3. That the **SELLER** declares under oath, which is understood as made upon signing this document, that it holds fifty percent (50%) of the crude production from the Chaza field and thirty five percent (35%) of the Guayuyaco field; (hereinafter the "Fields"), which shall be committed herein after deducting the percentage corresponding to royalties.
4. That through Public document No. 1682 of Notary Public Six (6) of Bogotá D.C., from March 2, 2007, registered on March 7, 2007 under number 144736 of Book 06, authentic copies of the company **PETROLIFERA PETROLEUM (COLOMBIA) LIMITED** creation were formalized, which is domiciled in Barbados, as well as copies of its by-laws and the resolution that provides for the establishment of a branch office in Colombia.
5. That through Public document No. 7814 of Notary Public Office Nine (9) of Bogotá D.C. dated November 1, 2012, registered on November 8, 2012 under number 00216638 of book IX, by virtue of the merger between the parent company **SOLANA PETROLEUM EXPLORATION (COLOMBIA) LIMITED (ABSORBED)** and the parent company **PETROLIFERA PETROLEUM (COLOMBIA) LIMITED (ABSORBING COMPANY)**, the branch office **SOLANA PETROLEUM EXPLORATION (COLOMBIA) LIMITED** is incorporated in the reference branch.
6. That for the purposes herein, the **SELLER** has signed contracts with the **VICE PRESIDENCY OF TRANSPORT AND LOGISTICS OF ECOPETROL S.A.**, the purpose of which is to render liquid hydrocarbon transport services through the **Oleoducto Transandino - OTA**.
7. That the contract signed by the **SELLER** and the **VICE PRESIDENCY OF TRANSPORT AND LOGISTICS OF ECOPETROL S.A.** is an essential consideration to subscribe to this Agreement.
8. That for purposes of carrying out this Contract, the **SELLER** has or will enter into a contract with the **VICE PRESIDENCY OF PRODUCTION OF ECOPETROL S.A.**, the purpose of which is to unload at the Dina Station and this contract is an essential consideration for the subscription of this Contract.
9. That for purposes of subscribing to this Contract, the **BUYER** previously verified in the Taxpayer Bulletin prepared and published by the General Comptroller's Office of the Republic, that the **SELLER** is not listed in such bulletin as one of the persons having a firm taxpayer liability verdict in force, and who have not fulfilled the obligation therein contained. Likewise, the **BUYER** implemented the control mechanisms related to asset laundering prevention and developed the instruments for the correct enforcement thereof, in furtherance of the Asset Laundering Prevention and Terrorism Financing Policy.
10. That on November 9, 2012, **the BUYER** held a meeting to review the crude purchasing negotiation conditions derived from the Guayuyaco Association Contract and the Chaza Block to **PETROLIFERA PETROLEUM (COLOMBIA) LIMITED** .

11. That as provided for in the Authority Delegations Manual of **ECOPETROL S.A.**, the **Planning and Supply Manager** is competent to subscribe to this Contract.
12. That the **BUYER** in its expenditure budget, owns the respective budget availability to execute the Contract referred to in this document.
13. That pursuant to the provisions of the Contracting Manual of **ECOPETROL S.A.** and after analyzing the nature and the form of execution of the provisions in charge of the Parties in furtherance of this Contract, the Authorized Official has qualified the risk as low and, consequently, abstains from requesting a security to **the SELLER**.
14. That based on the contractual planning made, consultation was made with the Tax Consultancy and Management Coordination of **ECOPETROL S.A.**, in order to avoid any tax risk that could be accrued for the Company as a consequence of the entering into and execution of this Contract.
15. That the **BUYER** verified compliance of its obligations with the social security system by the **SELLER** through a certificate signed by the statutory auditor of the **SELLER**.
16. In furtherance of the Asset Laundering Prevention and Terrorism Financing Policy adopted by the **BUYER**, the Legal Representative of the **SELLER** declares, under oath, subject to the sanctions set out in the Penal Code:
 - I. That my funds (or the funds of the entity I represent) are derived from legal activities and are related to the normal course of my activities (or the activities inherent to the corporate purpose of the company I represent) and that they are not derived from any of the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it.
 - II. That I (or the entity I represent) have not made any transactions or operations aimed at the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it, or in favor of persons related to such activities.
 - III. That the resources committed in the contract or legal relation with the **BUYER** are not derived from any of the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it.
 - IV. That in furtherance of the contract execution or legal relation with the **BUYER**, I will not engage nor will I have relations with third parties carrying out operations or whose resources are derived from the illegal activities set out in the Colombian Penal Code or in any norm that replaces it, adds to it or amends it.
 - V. That the entity I represent complies with the norms regarding asset laundering prevention and control and terrorism financing (LA/FT in Spanish), as applicable (as the case may be), after implementing the policies, procedures and mechanisms to prevent and control LA/FT, as derived from such legal provisions. Certification model is attached as Annex 1.

- VI. That neither I or the entity I represent, or its shareholders, partners or associates who directly or indirectly own FIVE PERCENT (5%) or more of the capital stock, contribution or share, its legal representatives and members of the Board of Directors are included in international lists which may be binding for Colombia, pursuant to the international law (UN lists) or in the OFAC lists, being the **BUYER** empowered to make the verifications deemed convenient and to terminate any commercial or legal relation if confirming that any of such persons are included in such lists. Certification model is attached as Annex 2.
- VII. That against me, or against the entity I represent or its shareholders, associates or partners who directly or indirectly have FIVE PERCENT (5%) or more of the capital stock, contribution or share, its legal representatives and members of the Board of Directors, there are no investigations or criminal processes for INTENTIONAL CRIMES, being the **BUYER** empowered to make the verifications deemed convenient in databases or national or international public information and to terminate any commercial or legal relation if confirming that any of such persons are involved in such investigations or processes or if such databases include information that may expose the **BUYER** to a legal or reputation risk.
- VIII. That in the event that any of the circumstances described in the two above paragraphs, I undertake to communicate it forthwith to the **BUYER**.
- IX. That upon signing this document, it is understood that both I, and the individual or company I represent, grant our informed consent and, therefore, authorize the **BUYER** to communicate to the national authorities or to the authorities of any of the countries where the **BUYER** conducts operations about any of the situations described herein, as well as to furnish to the pertinent authorities of such countries every personal, public, private or semi-private information about myself or about the individual or company I represent, as required. Likewise, for the **BUYER** to issue the reports to the competent authorities deemed convenient, pursuant to their regulations and manuals related to the asset laundering and terrorism financing risk prevention and /or administration system, releasing it from any liability derived from the event.
- X. That every documentation and information furnished to enter into and execute the contract or legal business with the **BUYER** is true and accurate, being the **BUYER** empowered to make the verifications deemed convenient and to terminate the contract or legal business upon verifying or confirming otherwise.
- XI. That no other individual or company has an illegitimate interest on the contract or legal business that leads to the subscription of this statement.
- XII. That I know, declare and accept that the **BUYER** is legally obliged to request the clarifications deemed convenient in the event of circumstances where the **BUYER** can have reasonable doubts regarding my operations or the operations of the individual or company I represent, as well as the origin of our assets, case in which we undertake to provide the respective clarifications. If not satisfactory in the opinion of the **BUYER**, we authorize the termination of any commercial or legal business.

Based on the foregoing, the Parties,

AGREE

CLAUSE ONE. PURPOSE AND QUANTITIES: The **BUYER** undertakes to acquire up to one hundred percent (100%) of the crude owned by the **SELLER** produced in the Guayuyaco Association Contract and the Chaza E&P Contract owned by the **SELLER** and the latter, on its part, undertakes to sell and deliver up to one hundred percent (100%) of its crude produced in the aforementioned contracts. This Contract excludes the crude of volume derived from royalties.

For the purposes of this Contract, one barrel is equivalent to one hundred fifty eight thousand nine hundred and eighty-eight (158,988) liters.

PARAGRAPH ONE: CRUDE OIL DESTINATION The **BUYER** shall use the crude oil acquired at the Tumaco Station for the export, through the Tumaco port, the crude acquired in Orito for the export through Ecuador, and the crude oil received at the Dina Station for the export through the Coveñas Port or for Refining purposes. The **BUYER** may also: i) use the crude oil hereunder for the export through other ports and / or ii) for refining purposes by notifying the **SELLER** in writing.

PARAGRAPH TWO: The receipt of volumes to comply with the purpose of this Contract is subject to:

- i. The subscription of the respective transport contract through pipelines with the Vice-presidency of Transport and Logistics (VIT) of Ecopetrol S.A., or whoever acts as such.
- ii. The availability of receipt and transport facilities scheduled by the Vice-presidency of Transport and Logistics (VIT) of Ecopetrol S.A., or whoever acts as such.

CLAUSE TWO. PRICE: The price payable for the crude hereunder, placed at the Point(s) of Delivery set out in Clause Six herein shall be established as indicated below for the different components, part of the following formula(s):

A. For crude oil exported as Southblend through the Tumaco port and received at the Tumaco Plant:

Crude Oil Price = Indicator – Port Operation Rate – Marketability Rate

Below we define each of the foregoing terms:

Indicator: Corresponds to the average price of South Blend Crude exports in USD/bl made by the Foreign Trade Management of Ecopetrol S.A. (including crude oil negotiated on behalf of affiliates) in the month of deliveries through the Tumaco Port. This price shall be reported by the **BUYER**. Should no exports have

been made in the delivery month, the parties shall apply the provisions set out in Paragraph One of Clause Three herein. The South Blend reference quality is 29.3° API and 0.62% Sulphur (S).

Port Operation Rate: Corresponds to a value of seven thousand sixteen ten-thousandth US dollars per barrel (US\$ / BI 0,7016).

Marketability Rate: Corresponds to one dollar and fifty cents of a US Dollar per barrel (US\$ / BI 1,50).

B. For crude exported as Eastern Crude through Ecuador:

Crude Oil Price = Indicator – Transport (Delivery Site /Shipping Port) – Transport Tax – Marketability Rate

Below we define each of the foregoing terms:

Indicator: Corresponds to the actual weighted average price of exports made by the **BUYER** of Eastern Crude in the month of deliveries or including crude oil shipped by the **BUYER** through the Balao port, associated with the deliveries. If during the delivery month, no exports are made through the Balao port, the price of the following export made, which includes crude oil owned by the **SELLER** shall be applied.

Transport (Delivery Site/ Shipping Port): Determined by adding the following rates:

Section	MME Resolution	Base100% MME Rate US\$/BI
Orito – San Miguel (OSO)	124572	2,3472
La Ye - Orito (OMO)	124560	0,5387
Total Transport		2,8859

- Furthermore, the rate charged by PETROECUADOR for transporting crude between San Miguel and the port of Balao.

Transport Tax: Determined as provided for in Article 52 of the Colombian Petroleum Code for domestic systems set out in the prior section. For the Ecuadorian section, the respective tax, if applicable, shall be considered from the delivery site to the shipping port.

Section	MME Rate US\$/BI	Transport Tax %	Transport Tax US\$/BI
Orito – San Miguel (OSO)	2,3472	2%	0,0469
La Ye – Orito (OMO)	0,5387	2%	0,0108
Total Tax			0,0577

Marketability Rate: Corresponds to one dollar and fifty cents of a US Dollar per barrel (US\$ / BI 1,50).

C. For the crude delivered to the Dina Station for export through the Coveñas port or for refining purposes:

Crude Oil Price = Indicator – Transport (Delivery Site /Shipping Port) – Transport Tax – Marketability Rate - Port Operation Rate

Below we define each of the foregoing terms:

Indicator: Corresponds to the average export price of the Crude Corporate Group in the Vasconia export blend through the Coveñas Port, negotiated in the crude oil delivery month. This price shall be reported by the **BUYER**. The Vasconia export blend Crude reference quality is 24.8° API and 0.97 % Sulphur (S). In the event that Ecopetrol's Corporate Group fails to make the exports in the delivery month, the indicator shall correspond to the Vasconia Crude export average reported by Argus & Platts for the delivery month. This value shall be reported every month by the **BUYER**.

Transport (Delivery Site/ Shipping Port): Determined as the sum of the rates set out by the Ministry of Mines and Energy for the pipeline between Tenay and Coveñas. Pipeline transport rates shall be adjusted each year through the "Phi" Factor, as provided for by the Ministry of Mines and Energy. The rates applicable in 2012 are:

Section	Sanctioning Resolution	Base100% MME Rate US\$/BI
Tenay –Vasconia	OAM	2,6035
Vasconia – Coveñas ODC	ODC	1,7053
Total Transport		4,3088

Transport Tax: Determined as provided for in Article 52 of the Colombian Petroleum Code (or the norm that amends it) for domestic systems set out in the prior section, based on the following details:

Section	MME Rate US\$/BI	Transport Tax %	Transport Tax US\$/BI
Tenay –Vasconia	2,6035	2%	0,0521
Vasconia – Coveñas ODC	1,7053	2%	0,0341
Total Tax	4,3088		0,0862

Marketability Rate: Corresponds to one dollar and fifty cents of a US Dollar per barrel (US\$ / BI 1,50).

Port Operation Rate: Corresponds to a value of six thousand one hundred and ten ten-thousandth US dollars per barrel (US\$ / BI 0,6110).

PARAGRAPH ONE: The price determined through the aforementioned formula includes the different transport, handling, metering and transport tax costs payable by the **SELLER**, accrued up to the delivery of crude oil hereunder at the Points of Delivery; therefore, the **BUYER** shall make no further payments for the aforementioned concepts.

PARAGRAPH TWO: When the Parties agree Points of Delivery other than those set out in Clause Six, the price formula provided for in this Clause shall be amended in the transport item, taking into account the crude transport rates and taxes via pipeline in force between the Point of Delivery and the applicable export port. Likewise, the indicator shall be modified, as applicable, prior agreement between the parties.

PARAGRAPH THREE: Receipt and metering costs, in the case of stations agreed by the Parties, and which are not operated by **ECOPETROL S.A.** shall be directly paid by the **SELLER** to the respective operating company. **The BUYER** shall make no additional payments whatsoever for such concepts. The Unloading rate value at the Dina Station corresponds to the value charged by the Vice-Presidency of Production or the corresponding area, as agreed in the Unloading contract.

PARAGRAPH FOUR: PRICE RENEGOTIATION. Any of the Parties may request a review of the prices set out herein, provided any of the following events takes place:

- a) A change of nearly two (2) API grades in the quality of crude oil produced on the field / area / block / contract.
- b) A change of nearly two (2) API grades in the quality of the Indicator Crude during three (3) consecutive months. In this case, the review request must be made during the month following the period of three (3) consecutive months.
- c) In case that the Indicator Crude disappears and a new Indicator is to be defined.

The Parties shall have a thirty (30) business day-term to negotiate. Should an agreement be reached, evidence thereof shall be recorded by signing an amendment by the **BUYER** and the **SELLER** and the provisions therein shall apply as of the day following the date in which such amendment is signed.

If at the end of the thirty (30) business-day term, no agreement is reached, the **BUYER** or the **SELLER** may notify the other party its intent to terminate the Contract, as provided for in Clause Twenty One of this Contract.

The termination shall not release the Parties from complying with the obligations already accrued.

PARAGRAPH FIVE: QUALITY SPECIFICATIONS. The quality of crude received shall be guaranteed by the Seller up to the Point of Delivery; however, it shall be verified by the **BUYER** at the Point of Delivery set out in Clause Six and shall comply with the following quality specifications:

Field	° API Minimum	SULPHUR (% weight) Maximum	BSW (% in volume) Maximum	SAL (Lb/1000Bls) Maximum
Guayuyaco	25.0°	0,70	0,50	20,0
Chaza	29.0°	0,41	0,50	20,0

1. Crude density shall be determined through the ASTM-D-1298 Lab method (Method to determine density, specific density (specific gravity) or API Gravity of crude and liquid oil products through the Hydrometer method).
2. The water and sediment content, BSW, shall be determined through the methods:
Suspended water ASTM-D4377 “Method to determine water in crude oil through Karl Fisher titrimeter and ASTM-D473 Sediments” and “Method to determine sediments in crude and fuel oils by extraction”. For the water and sediment content in crude, the following shall be accepted as maximum individual values: 0.50% water volume and 0.01% sediment volume.
3. The sulphur content shall be determined through method ASTM-D4294 “Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy Dispersive X-ray Fluorescence Spectrometry”.
4. The salt content shall be determined through ASTM-D3230 "Standard Test Method for Salts in Crude Oil through Electrometric Method".

When the BSW, Salt and Sulfur specifications herein established are not within the margin allowed, the **BUYER** reserves its right to receive crude oil and to buy them at a BSW and Salt-adjusted price. In these cases, the crude price shall be adjusted, based on the following tables:

BSW Content % Volume	Correction(US\$/Barrel)	In charge of
0.51 to 0.80	0,10	THE SELLER
0.81 to 1.00	0,20	THE SELLER
1.01 to 1.20	0,30	THE SELLER
1.21 to 1.50	0,40	THE SELLER
>a 1,51	Not received	
Salt Content Pounds for every thousand Barrels	Correction (US\$/Barrel)	In charge of
20.1 to 30.0	160	THE SELLER
30.1 to 40.0	180	THE SELLER
40.1 to 60.0	200	THE SELLER
60.1 to 80.0	220	THE SELLER
80.1 to 100.0	240	THE SELLER
>a 100.0	Not received	

It is understood that the **SELLER** shall make sure it delivers the crude oil hereunder with the BSW and Salt content within the parameters agreed. These corrections shall be applied to daily deliveries or to each batch delivered.

In case that crude deliveries exceed the maximum values set out in the table (1.51 BSW and 100.0 lbs of salt for every thousand barrels) and if the **BUYER** decides to receive the crude, the Parties shall agree the value of the corresponding correction and evidence thereof shall be included in an Amendment signed by the parties. Should no agreement be reached, the **BUYER** may reject the crude.

PARAGRAPH SIX: Reimbursable expenses: Reimbursable expenses may not exceed forty million pesos (COP 40,000,000), VAT excluded per year, and shall be previously authorized and approved by the **BUYER**. In this case, the cost of the independent inspector shall be solely and exclusively paid, as referred to in Paragraph Two of Clause Five herein.

The amount of the reimbursable expenses shall not be part of the Contract value. The management of reimbursable expenditures shall be made in accordance with the procedures in force implemented by the **BUYER** for this type of expenditures (annex 3).

CLAUSE THREE. INVOICING AND PAYMENT: The **SELLER** shall invoice and collect from the **BUYER** the cost of the crude sold, as provided for herein, in his Accounts Payable offices in Bogotá, within the first ten (10) business days of the month following the crude delivery(ies) to the **BUYER**. Within the first six (6) business days of the month following the deliveries, the **BUYER** shall provide to the **SELLER** the information it requires to issue the corresponding invoice. Invoices must be filed at the Accounts Payable

offices of the **BUYER** in Bogotá and its valid submittal date for payment shall be that set out as receipt at the Accounts Payable office of the **BUYER** in Bogota. Invoicing shall be made based on net volumes, water and sediment-free, corrected at sixty (60) Fahrenheit degrees, received at the Point(s) of Delivery. For invoice approval, they must be submitted in the official forms of Chart No. 4 and/or Form No. 9SH of the Ministry of Mines and Energy. In the event that the Ministry of Mines and Energy fails to deliver the signed Charts No. 4 and /or Form No. 9SH corresponding to the month being invoiced, Charts No. 4 and/ or Form No. 9SH submitted to the Ministry of Mines and Energy pending signature shall be temporarily accepted, but every quarter, the **VENDOR** shall submit to the **BUYER** a copy of Charts No. 4 and /or Form No. 9SH of the immediately previous quarter, duly completed and signed by the Ministry of Mines and Energy.

Taking into account the foreign currency payment authorization set out in Article 51 of External Resolution No. 8 of 2000 of the Board of Directors of the Central Bank, which provides that domestically-produced crude oil and natural gas purchase-sales made by the **BUYER** and other entities devoted to the oil refining industrial activity can be paid in foreign currency, the invoicing that the **SELLER** issues for the supply of crude to the **BUYER** may be made in dollars of the United States of America.

In every case, payment shall be made 100% in dollars and shall be made thirty (30) calendar days following the submittal of invoices duly completed, prior legal withholdings, if applicable. **The SELLER** shall notify the **BUYER** in advance and in writing the bank account where the respective payment is to be made.

PARAGRAPH ONE: Invoicing for deliveries to the Port of Tumaco: Crude deliveries shall be invoiced in accordance with the volumes and prices notified by the Ecopetrol S.A. Crude Procurement Coordination during the first six (6) business days following the end of the delivery month; such volumes shall be subsequently adjusted based on the compensated volumes of the official volumetric offset compensation prepared by the Vice-Presidency of Transport and Logistics of Ecopetrol or whoever acts as such.

Once the volumetric compensation is received, the **SELLER** shall be responsible for invoicing and filing at the Accounts Payable office of the **BUYER** the respective adjustments within the three (3) business days following the receipt of the volumetric compensation, taking into account the receipt dates at Ecopetrol's Accounts Payable offices.

For those months where South Blend exports are not made through the Tumaco Port, the price to be used shall correspond to the weighted average of the volume reported in the commercial meter corresponding to the last month in which South Blend exports had been made, or the blend exported through the port of Tumaco; such price shall be adjusted to the average price weighted by export volume of the South Blend or the blend exported through the Port of Tumaco in the month of deliveries or, if no exports were made in the month of deliveries, with the price for the following month in which exports are carried out.

Based on the conditions set out herein, no payments corresponding to volumes not received at the Tumaco plant shall be made.

PARAGRAPH TWO. For deliveries to the Orito Station for export through Ecuador: In the event that by the date to invoice the export crude through the Balao port, no final export price, volumes exported or rates collected by Petroecuador in formation is available, invoicing shall proceed in accordance with the crude volume shipped from the Orito Station, prorated by the volumes delivered by each operator. The price to be used shall correspond to the arithmetical average of the daily quotes of Eastern crude reported by the Platt's Agency shall be used, during the days in which crude was pumped to Lago Agrio.

Invoicing shall be adjusted once final information of volumes and prices of the East Blend crude exported by Petroecuador with volumes pumped from Colombia is available, notifying the presence of crude oil delivered by the **SELLER**.

Once the information of East Crude exports made through the Balao Port with crude volumes from Colombia, and specifically hereunder is received, the **SELLER** shall be responsible for invoicing and submitted to the accounts payable office of the **BUYER** the respective adjustments within the following three (3) business days after the respective information is received, taking into account the accounts payable receipt dates Ecopetrol.

PARAGRAPH THREE: The BUYER shall have a term of ten (10) business days, counted as of the receipt of the crude sales invoices to review them or object them. Should invoices be questioned, the receipt date shall be that of the filing of the new invoice. **The BUYER** shall notify the **SELLER** within the term foreseen about any invoice questioned, for it to be adjusted and corrected, by clearly indicating the items to be adjusted or corrected and the corresponding reasons thereof. **The SELLER** shall respond to the objection within ten (10) business days following the receipt thereof, counted as of the time in which the **BUYER** submits to the **BUYER** all the documents that gave rise to the objection, unless the Parties determine by common consent to extend the term if the objection complexity or if any reasonable circumstance so requires.

In the event that the **SELLER** fails to respond to the objection within the aforementioned term the objection shall be considered accepted by the **SELLER**. Should the **SELLER** resolve the objection in favor of the **BUYER**, it shall be understood that there was no payment obligation over the invoice originally filed, subjected to objection. Should the **SELLER** resolve the objection in its favor, the **BUYER** shall endeavour to solve the dispute forthwith, based on the provisions of this contract, in order to make the payment of the unpaid amount. To solve any discrepancy, each of the Parties shall submit to the other a copy of the documents that gave rise to the invoice and to the objection. In the event that the **BUYER** disagrees with the decision of the **SELLER**, it may apply the provisions set out in Clause Seventeen of the Contract.

PARAGRAPH FOUR: In the event of unjustified delay on the payment of invoices not objected in due time by the **BUYER**, as foreseen in Paragraph Three herein, the **BUYER** shall pay to the **SELLER**, as interest rate payable in pesos, the maximum arrears interest rate authorized by the Financial Superintendence during the arrears days effectively elapsed.

For purposes of calculating late interests, the amount of dollar invoice(s) in arrears shall be converted first into Colombian pesos, at the market representative exchange rate in force on the date of issuance, as certified by the Financial Superintendence of Colombia.

Invoices for interest collection shall be paid by the **BUYER** thirty (30) calendar days following the receipt thereof by the **BUYER**.

Both the **BUYER** and the **SELLER** understand that invoices issued, as well as this Contract shall give right of execution and the **BUYER** and **SELLER** expressly waive to the private or legal requisites to be declared in arrears.

PARAGRAPH FIVE: In case that the **SELLER** becomes interested in doing factoring with the invoices issued with respect to this Contract, it shall first offer the option to the **BUYER**.

CLAUSE FOUR. CONTRACT TERM: The Contract term shall begin with its formalization and shall include the execution and liquidation term.

The Contract execution term shall begin upon signing this document and shall end on November 30, 2013.

Within a term of four (4) months counted as of the date of Contract Execution term ending, the parties shall sign the respective liquidation minutes.

In the event that the **SELLER** fails to attend to the liquidation or if no agreement is reached on the contents thereof within the aforementioned term, it shall expressly empower the **BUYER** to proceed with the unilateral liquidation within two (2) months.

CLAUSE FIVE. INSPECTION AND METERING. The quantity and quality shall be measured at the Point(s) of Delivery defined in Clause Six, and shall be made following the operative procedures, instructions, recommendations and methods set out in the Hydrocarbons Metering Manual of **ECOPETROL S.A.**, (hereinafter the "MMH"), attached hereto as Annex 4. In the event of amendments, additions or deletions to the MMH, the **BUYER** shall notify the **SELLER** of such changes, which shall be mandatory upon notice. Quantity and quality metering shall be made by qualified personnel. The stations and / or dependencies of the **BUYER** and/or associates where crude is received shall certify the volume and quality (API, BSW and SAL) of the crude received every day therein. In case of deliveries at Tumaco, volumes and quality are determined through volumetric compensation.

PARAGRAPH ONE: QUANTITY METERING. The volume shall be calculated as the Net Standard Volume (NSV) and shall be understood as the total volume of all oil liquids, excluding sediment and water (BSW) at a standard temperature of 60° F. Metering can be made through static or dynamic metering, applying the methods described in the MMH. The volume used to calculate the crude delivered by the

SELLER at the inlet flange at the Tumaco Plant shall be the volume resulting after the application of the volumetric compensation and sent by the Transport and Logistics Vice-Presidency. For crude delivered at the inlet Flange to the Orito Station tanks for crude exported as Eastern Crude through Ecuador and for crude delivered at the Dina Station, it shall be made in accordance with the invoicing and payment Clause.

PARAGRAPH TWO: QUALITY METERING. Quality metering shall allow determining the actual characteristics of crude hereunder. In determining the above, a representative sample of the total volume shall be available, as described in MMH, Chapters 8, 9, 10 and 14, and shall serve to establish the deviations that may affect hydrocarbon price.

The crude sulphur content for invoicing purposes shall be that reported by the Colombian Oil Institute (ICP), based on the semester analyses made for each crude. **The BUYER** shall update this information every six months and shall deliver it to the **SELLER**. In the event that the sulfur content analysis made by ICP is not available, the sulfur content shall be, for invoicing purposes, that set out in Paragraph Five of Clause Two of this document, which shall be in force until the ICP makes a new analysis and it is reported to the **SELLER** by the **BUYER**. As of the day following the receipt of the information analysis made by the ICP by the **SELLER**, the crude sulfur content for invoicing purposes shall be that set out by the **BUYER** in such report. Any of the Parties, when deemed convenient, can request a new sulfur content analysis by the ICP.

Any of the Parties may designate, as required, an independent inspector to certify the quality and quantity, verify the capacity of tanks or the calibration of the volume metering instruments. The cost of the analyses or inspections shall be equally shared by the **BUYER** and the **SELLER**.

The SELLER shall be responsible for paying the fees of the external inspector. **The BUYER** shall pay to the **SELLER** half of its share of the invoices issued by the external inspector as a reimbursable expenditure, as per Paragraph Six of Clause Two.

CLAUSE SIX. POINTS OF DELIVERY: **The BUYER** and the **SELLER** agree that the Point(s) of Delivery and transfer of crude ownership hereunder shall be: i) Inlet flange to the main tanks at the Tumaco Plant for crude exported as South Blend, ii) Inlet flange to the Orito Station tanks for crude exported as Eastern Crude through Ecuador and iii) Unloading line flange of tanker trucks at the Dina Station for crude bought for export through the Coveñas port or for refining purposes. At all of these points, delivery shall be made by metering tanks and/or with a flow meter, following the procedures set out in Clause Five of this document.

The SELLER transfers to the **BUYER** the ownership over the Crude at the Point(s) of Delivery. **The SELLER** guarantees that upon delivery, crude shall be free of any lien or economic burdens by any government entity of any level or natural person or corporation, for any concept including, among others, those derived from taxes, rates, contributions, shares or royalties, encumbrance or any legal or out-of-court measure that may restrict or limit the use or disposal of crude by the **BUYER**. The costs related to the

transport of crude to the Point(s) of Delivery as well as the costs associated with crude delivery shall be paid by the **SELLER**.

PARAGRAPH ONE: Any of the Parties may propose the change or addition of a Point of Delivery; in such case, the Parties, by mutual consent, shall define the new Point(s) of Delivery and the conditions governing over them through an amendment to be signed by the legal representatives of the Parties.

PARAGRAPH TWO: The volumes to be received at each of the stations defined in this clause shall be established on a monthly basis, based on the official transport schedule established by the **BUYER**.

CLAUSE SEVEN. DELIVERY SCHEDULE: For deliveries at the inlet flange of the Tumaco Plant tanks for crude exported as South Blend, the parties acknowledge and accept that the delivery program provided for by virtue of this Contract is subjected to the commitments agreed in the transport contract, which includes the Operation and Transport Regulation signed by the **SELLER** and the **VICE-PRESIDENCY OF TRANSPORT AND LOGISTICS OF ECOPETROL S.A.** Consequently, the **SELLER** shall nominate crude to be transported and delivered, pursuant to the terms and conditions defined in Clause 8 of the Ecopetrol Pipeline Transporter Manual. Likewise, the volumes to be received by the **BUYER** shall be those approved by the **TRANSPORTER**, pursuant to Clause 8, Number 8.4.1 of the Ecopetrol Pipeline Transporter Manual.

In the event of a force majeure case, the delivery schedule shall be redefined. This new schedule shall be agreed between the **BUYER** and the **SELLER**.

It is the **SELLER's** obligation to furnish and maintain field information on the production, calculation of royalties, shipments through tanker trucks and / or pipelines, indicating share and ownership of each one and the official receipt at the receipt station. To such end, it shall submit on a daily basis to the **BUYER** the information requested through the volumetric integrator of the **BUYER** available through the Web page, for which the User Manual is attached as Annex 5.

It is the **SELLER's** obligation to complete the respective transport document (as applicable), indicating fields and volumes dispatched on each tanker truck and describing on the "Observations" field that the crude corresponds to a sale to Ecopetrol S.A.

In the event that within the term agreed, the **BUYER** cannot receive all the crude at the Point(s) of Delivery, it shall so notify it to the **SELLER** minimum three (3) calendar days in advance and as soon as the contingency is solved, it shall announce the date to reactivate receipts.

Likewise, in the event that for reasons inherent to the field operation, the **SELLER** cannot deliver to the **BUYER** the crude in any of the dates determined in the schedule, it shall notify the **BUYER** in writing

three (3) calendar days prior to the respective delivery date and as soon as the contingency is solved, it shall announce the date to reactivate deliveries.

Should a place other than that set out for crude receipt is indicated, the parties shall make the adjustments established in the transport item and in the transport tax, in the formulas defined in Clause Two of this document, pursuant to the highest or lowest value required for transport to the new Point(s) of Delivery defined by the **BUYER**, considering for the purpose the transport rates in force when the situation takes place. All of the above shall be evidenced in minutes or amendment, which shall be signed by the Parties for the purpose.

CLAUSE EIGHT. SAFETY - HSE: It is a special obligation of the **SELLER** to have a hygiene, safety and occupational health program for the Crude transport operation to the Point(s) of Delivery.

CLAUSE NINE. CONTRACT ADMINISTRATION AND MANAGEMENT: The Authorized Official of **ECOPETROL S.A.** shall designate the Contract administration and management; those assigned with such responsibility shall have the powers and obligations foreseen in the Guideline for Contract and / or Agreement Administration and Management of **ECOPETROL S.A.**, which is incorporated hereto as Annex 6.

The BUYER shall evaluate vendor's performance as Contractor at the end of the Contract, pursuant to the "Contractor Performance Evaluation" guideline, which shall be furnished by the **CONTRACTOR** to the **SELLER** once the Contract is formalized.

CLAUSE TEN. ASSIGNMENT: **The SELLER** may not assign, sell or transfer all or part of its rights and obligations herein contracted to a third party, without the prior, written consent of the **BUYER**.

CLAUSE ELEVEN. FORFEITURE: **The BUYER** shall terminate the Contract and order its liquidation, regardless of the status, when the **SELLER** incurs in the conducts forbidden in article 25 of Law 40 of 1993 (payment of sums of money to extortionists or hide or cooperate by any executive or delegate of the **SELLER** in the payment for the release of a kidnapped person, who is an official or employee of the **SELLER** or any of its affiliates).

If forfeiture is declared, there shall be no grounds to pay indemnification to the **VENDOR**, who shall become responsible for the sanctions and inabilities foreseen in the Law. The forfeiture declaration shall constitute grounds for default. **ECOPETROL S.A.** shall declare forfeiture through grounded resolution that will be notified in due time to the **SELLER**, who may file any legal remedies. **The SELLER** shall be entitled, prior deductions applicable pursuant to the clauses of this Contract, to receive payment for the part of the goods or services received at satisfaction by the **BUYER** up to the date of the forfeiture declaration.

CLAUSE TWELVE. FORCE MAJEURE, ACT OF GOD AND THIRD PARTY EVENTS: The obligations of any of the Parties derived herefrom, which may not be fulfilled due to Force Majeure, Act of God or Third Party Event, total or partial, shall be suspended during the time the effects thereof last.

The party invoking the occurrence of a Force Majeure, Act of God or Third Party Event shall notify the other Party about such situation, including commencement date and time, immediately over the phone and in writing on the business day following the occurrence of the event, submitting the evidence that prove the occurrence thereof. The Party notified about the Force Majeure, Act of God or Third Party Event may request the submittal of additional information to support the declaration, and the affected party shall submit it within five (5) business days following the request thereof. Should there be differences between the Parties as to the event set-up, the parties shall proceed in accordance with the dispute settlement mechanisms foreseen in Clause Sixteen herein.

The Party invoking the occurrence of a Force Majeure, Act of God or Third Party event shall endeavour to correct the cause that led to the declaration thereof, and shall notify the other Party about the date and time in which such event was resolved.

For the purposes of this Contract, Force Majeure or Act of God event is every event that may be classified as such according to the Applicable Law, whether unforeseen and irresistible, duly proven, and provided it is beyond the reach of the Parties and if it takes place without their fault or negligence.

Force Majeure or Act of God events include, among others, the following acts or events: a) Epidemic outbreak, landslides, hurricanes, floods, avalanches, lightning, earthquakes, tidal waves, shipwreck, disaster during ground, air, railway, river and sea transportation, which directly or indirectly contribute or result in any of the Party's impossibility to fulfill its obligations. b) Acts or lack of acts by the Government and the Legislative and Judicial branches of it, including laws, orders, regulations, decrees, rulings, judicial actions, regulations, issuance denial, renewal or confirmation of permits and licenses made by the Government or the competent authority having jurisdiction over the production, treatment, collection, transport, distribution and purchase-sale of crude and / or product activities, and which directly or indirectly contribute to, or result in the failure by any of the Parties to meet its obligations, or which seriously or unfairly affect the interests of any of the Parties, or seriously affect their financial capacity. c) Civil riots, including war, blockages, insurrection, massive protests and serious threat of any of the above, fully demonstrated, and actions of military forces related to, or in response to any act of civil upset, which directly or indirectly contribute or result in the Parties' failure to comply with their obligations.

Third Party events include: a) Total or partial impossibility to operate and manage the facilities and installations for the production, management, transport, delivery or receipt of crude and / or products, and of the pipelines, tanker trucks, vessels or any other means used for the transportation thereof, as well as the connections or the facilities of any of the Parties, due to willful acts of third parties beyond the control and direct management of the **SELLER** or the **BUYER** without their fault, such as terrorist or guerrilla attacks or sabotage or the serious public order upset, among others, which directly or indirectly contribute or result

in, or lead to any of the Party's failure to comply with its obligations, b) Emergency shutdown at the facilities of the **SELLER** or the **BUYER** c) Industrial riots including the illegal suspension of activities and strikes when these acts contribute to affecting the **BUYER's** ability to comply with their obligations and d) Industrial upset acts, including activity suspension, strikes and blockages, when these acts contribute to, or result in the **SELLER's** inability to meet its obligations.

PARAGRAPH ONE: In no case shall the financial condition changes of the **BUYER** or the **SELLER** constitute a Third Party Event hereunder.

Neither the **BUYER** nor the **SELLER** shall be liable for the default or partial default of each and every obligation hereunder, if such default is caused by events that constitute Force Majeure, Act of God or Third Party events duly proven.

The Force Majeure, Act of God and/or Third Party events shall not release the **BUYER** from its obligation to pay to the **SELLER** those invoices for the sale of crude delivered by **SELLER**, in accordance with the terms set out in this CONTRACT.

The occurrence of any of the events foreseen herein shall not release or prevent, in any case, the Parties from complying with their obligations acquired and / or accrued prior to the occurrence of the events referred to in this clause.

CLAUSE THIRTEEN. COLOMBIAN LAW ENFORCEMENT: This Contract is governed by the Colombian laws.

CLAUSE FOURTEEN. TAXES: Each of the parties in this purchase-sale declares to know and accept the taxes and/or withholdings applicable, pursuant to the Laws in force. The payment of all national, departmental and municipal taxes, liens, rates, contributions, quotas or similar, accrued or to be accrued hereunder including, without limitation, those incurred in due to the entering into, formalization, execution and termination or liquidation of this Contract, or which may arise after the execution of this Contract shall be paid by the respective taxpayer, who shall pay them in accordance with the laws and regulations in force.

CLAUSE FIFTEEN. FORMALIZATION: This Contract is formalized upon the execution thereof.

CLAUSE SIXTEEN. CONFLICT RESOLUTION: In case of differences, conflicts or disputes related to the interpretation, execution and enforcement of this contract, the Parties shall refer to the alternate conflict resolution mechanisms legally regulated.

CLAUSE SEVENTEEN. SPANISH LANGUAGE: This Contract shall be written in Spanish and constitutes the sole form of obligations between the Parties. Any translation to another language shall be

considered a reference for the Parties, and in no case shall this affect the meaning or interpretation of the Spanish version.

CLAUSE EIGHTEEN. CONTRACT VALUE: The Contract value is undetermined.

CLAUSE NINETEEN. INFORMATION CONFIDENTIALITY: For the purposes herein, the Party that communicates or discloses information shall be hereinafter referred to as the Disclosing Party and the party that receives the information shall be hereinafter referred to as the Receiving Party. The Parties agree that all technical, commercial, industrial or financial information furnished, exchanged and / or prepared by the Parties in furtherance of this Contract, or developed, received or obtained by any of the Parties with respect to this Contract (hereinafter the "Confidential Information" or the "Information") shall be subjected to strict reserve and confidentiality during the Contract term, and for three (3) years following the date of termination thereof.

For the purposes of this Contract, Confidential Information is: (i) is of public domain upon disclosure or becomes known after the disclosure thereof, through different acts or omissions by the Receiving Party; (ii) is known by the Receiving Party before, upon it is received or obtained hereunder, without such knowledge being derived from the breach of a confidentiality obligation, (iii) is developed by the Receiving Party independently, or based on the information or documentation received from a third party, without the latter being considered, in turn, a breach of a confidentiality obligation; (iv) is received or obtained, in good faith, by the Receiving Party, from a third party, without this implying, in turn, a breach of a confidentiality obligation; (v) its dissemination and/or disclosure is required by the Receiving Party in furtherance of the legislation in force, legal provision, firm administrative act, competent legal and / or government authority with jurisdiction over the Parties or their affiliates, or by norms of any Stock Exchange, where the actions of the Parties or corporations related are registered, under the terms and to the extent required.

The Receiving Party may disclose the Confidential Information to its management, officials, employees, executives, agents, partners, representatives or associates, affiliates and subordinates (generically denominated Representatives).

It is requested or demanded by a judicial or administrative authority that the Receiving Party, by virtue of the law, regulation or judicial resolution, furnish any part of the Information; such Receiving Party may request cooperation of the Disclosing Party and, if convenient, shall enquire with it the measures to be taken to maintain confidentiality.

CLAUSE TWENTY. SPECIAL OBLIGATIONS OF THE SELLER RELATED TO THE PREVENTION AND CONTROL OF ASSET LAUNDERING AND TERRORISM FINANCING (LA/FT)

- a. To fully comply with the legal provisions on asset laundering prevention and control and terrorism financing (LA/FT) applicable by efficiently and timely implementing the policies and procedures needed for the purpose.
- b. To abstain from carrying out operations with persons or entities whose funds are derived from the illegal activities set out in the Penal Colombian Code or in any norm that replaces it, adds to it or amends it, or on those having grounded concerns about the origin of the resources, based on public information.
- c. To respect and adhere to the Good Governance Code, the Integral Responsibility Policies and the Corporate Social Responsibility Policy of Ecopetrol, the Code of Ethics and the policies to prevent, control and administer the asset laundering risk and terrorism financing (LA/FT) of the **BUYER**. For such purposes, the **SELLER** declares to know such documents.
- d. In such cases where activities are carried out, which are considered high LA/FT risk, it undertakes to adopt LA/FT prevention systems.
- e. To abstain from using its operations as instrument to conceal, manage, invest or utilize, in any way, cash or other goods derived from criminal activities or to try to convey legality in the transactions and funds related therewith, or aimed at carrying out illegal activities.
- f. To report to the **BUYER** (Telephones 018000917045 – (57-1-2343345 – 57-1-2344092) and to denounce to the competent authorities the crimes it becomes aware of (corruption, extortion, document forgery, asset laundering, terrorism financing and others), as provided for in Article 67 of the Criminal Procedure Code (Law 906 of 2004 and those that add to it or replace it).
- g. To report to the **BUYER** the incidents or events that may affect its image or reputation and / or that of the **BUYER** within three (3) business days following the occurrence thereof, in order to adequately manage them.
- h. To timely respond to the information requirements and clarifications requested by the **BUYER** in furtherance of this contract.

CLAUSE TWENTY ONE. EARLY TERMINATION:

21.1 The **SELLER** or the **BUYER** may terminate, at any time, this Purchase - Sale Contract, without it being obliged to indemnify for any type of prejudice to the other party, provided the party wishing to terminate the Contract in advance submits to the other a written communication within thirty (30) calendar days in advance to the date in which the Contract is to be terminated.

21.2. Likewise, those events related to asset laundering prevention and control and terrorism financing shall be considered grounds for early contract termination without this implying indemnification in favor of the **SELLER**, as well as the following:

1. When **the SELLER** fails to comply with the legal provisions related to asset laundering prevention and control and terrorism financing, as applicable.
2. When **the SELLER** or any of its shareholders, associates or partners who directly or indirectly own FIVE PERCENT (5%) or more of the stock capital, contribution or share, are included in the international lists which are binding for Colombia, pursuant to the international law (UN lists) or in the OFAC lists.
3. When the **SELLER** or its shareholders, associates or partners, having directly or indirectly FIVE PERCENT (5%) or more of the stock capital, contribution or share, its legal representatives and members of the Board of Directors are involved in investigations or criminal processes for wilfull acts, or if there is public information about such persons, which may expose the **BUYER** to a legal or reputation risk.
4. When situations take place, which may represent to the **BUYER** reputation, legal, operative or contagious risks related to asset laundering and / or terrorism financing.
5. When situations take place, which lead to founded concerns about the legality of the operations of the **SELLER**, the legal nature of the funds or if the **SELLER** has carried out transactions or operations aimed at such activities or in favor of persons related therewith.
6. When mistakes, inconsistencies, discrepancies or forgeries take place in the documentation and information furnished by the **SELLER** in entering into and executing this contract.

21.3 Likewise **the BUYER** may terminate the contractual relation when the **SELLER** incurs in any of the following conducts:

1. Unjustifiably give way to threats proffered by outlawed groups.
2. Receive, supply, administer, invest, finance, transfer, keep, transport, store or preserve monies or goods derived from, or targeted to such groups, and to provide support to such groups.
3. Build, assign, lease, make available, facilitate or transfer under any title goods to be used to conceal persons or to store or keep the belongings of such groups.
4. Paralyze, suspend or significantly reduce the compliance of its contractual obligations to follow the instructions of such groups.
5. Failing to denounce criminal events, the commission of which is imputable to such groups, known in furtherance of the Contract.

For the purposes of the above, the conduct of agents or dependents known to the Seller constitute an event imputable to it.

CLAUSE TWENTY TWO. NOTICES: All notices, requests, communications or notices that the Parties must exchange by virtue of this Contract shall be made in writing and shall be considered served upon the document's presentation at the address set out herein below.

THE BUYER

ECOPETROL S.A.
Planning and Supply Management
Bernardo Castro Castro
Carrera 7 No. 37-69 Piso 7, Bogotá D.C.
Telephone (+57) 1 234 4606
Fax (+57) 1 234 4869

THE SELLER

PETROLIFERA PETROLEUM COLOMBIA LIMITED
Carlos Felipe Marín / Juan Carlos Buitrago
Commercial Management
Calle 113 No. 7-80, piso 17
Telephone (+57) 6585757
Fax (+57) 2139327

Communications sent by fax shall be deemed served once the successful communication message from the machine where the communication is submitted is received.

CLAUSE TWENTY THREE. DOMICILE: For all legal purposes, the contractual domicile is established in the city of Bogotá, D.C.

In witness whereof, this document is signed in Bogotá D.C. on December 1st, 2012, in two identical counterparts.

THE SELLER	THE BUYER
<p style="text-align: center;"><u>/s/ Duncan Nightingale</u></p> <p style="text-align: center;">DUNCAN NIGHTINGALE Legal Representative</p> <p style="text-align: center;"><u>/s/ Alejandra Escobar Herrera</u></p> <p style="text-align: center;">ALEJANDRA ESCOBAR HERRERA Legal Representative</p>	<p style="text-align: center;"><u>/s/ Bernardo Castro Castro</u></p> <p style="text-align: center;">BERNARDO CASTRO CASTRO Planning and Supply Management</p>



GUNVOR COLOMBIA SAS

Carrera 7 No. 83-29, Oficina 304 Bogotá, Colombia
Phone +57-1 - 6227978 / 6364768

Exhibit 10.69

Date: December 3, 2012

COSTAYACO CRUDE OIL SALES / PURCHASE AGREEMENT

This **CRUDE OIL SALES / PURCHASE AGREEMENT** (hereinafter the "Agreement") is entered into on December 3, 2012 and shall be in effect as of this date, by and between GRAN TIERRA ENERGY COLOMBIA LTD a limited liability company organized under the Laws of the State of Utah, acting through its duly registered Colombian branch (hereinafter the "SELLER"), jointly represented by Alejandra Escobar Herrera, identified with Citizenship Card No. 52.646.943 and Manuel Antonio Buitrago Vives, identified with Citizenship Card No 72.191.666, duly authorized to enter into this Agreement pursuant to the Certificate of Incorporation and Legal Representation attached hereto, issued by the Chamber of Commerce, and GUNVOR COLOMBIA SAS, a company organized under the Laws of the Republic of Colombia (hereinafter the "BUYER"), represented by Jaime Alejandro Hoyos Juliao, bearer of Citizenship Card No. 80.082.474, duly authorized to enter into this Agreement pursuant to the vote in writing dated November 30, 2012 of the sole shareholder of Gunvor SAS, attached hereto. SELLER and BUYER shall be hereinafter individually referred to as a "PARTY", and collectively as the "PARTIES".

RECITALS:

1. **WHEREAS** SELLER is a company whose main purpose is exploring and producing crude oil in the Republic of Colombia.
2. **WHEREAS** SELLER is a party to the Chaza E&P Agreement entered into with the ANH (*Agencia Nacional de Hidrocarburos*), in the area located in the Department of Putumayo, Republic of Colombia.
3. **WHEREAS** SELLER is interested in selling the crude oil produced in Campo Costayaco (the "Crude"), located in the area of the Chaza E&P Agreement.
4. **WHEREAS** BUYER is a company whose main purpose is the purchase and subsequent sale of crude oil.
5. **WHEREAS** SELLER is interested in selling and BUYER is interested in purchasing SELLER's Crude, produced in *Campo Costayaco* located in Putumayo, Colombia, in an estimated amount of 3,650 BPD +10%.

NOW THEREFORE, in consideration of the premises and of the representations, warranties, pacts, agreements and mutual commitments established herein or those referred to herein, the PARTIES agree as follows:

1. PURPOSE

Subject to and pursuant to the terms and conditions herein, SELLER may sell and deliver, and BUYER may purchase and load when SELLER so nominates, up to a maximum amount of 3,650 barrels of crude + 10% per day during the term of the Agreement. SELLER undertakes to sell and deliver the Crude at the Delivery

Point (term defined in Clause 7 hereunder) in accordance with the technical specifications and conditions established herein. BUYER agrees to purchase and load the Crude at the Delivery Point and to pay SELLER the price agreed upon for the nominal volume received from SELLER at the Delivery Point, in accordance with the price conditions established in the Agreement.

SELLER shall make his best effort to deliver to BUYER no later than the last day of each month, an estimation of the amount of Crude it expects to deliver on a daily basis during the following month. Notwithstanding the aforesaid, SELLER, with prior notice of not less than 48 hours before any day that SELLER chooses to sell the Crude to BUYER, shall nominate the quantity of Crude (hereinafter the "Daily Nominated Quantity") that will be sold to SELLER at the Delivery Point on the day stated in such nomination. SELLER shall not be obliged to nominate a Daily Nominated Quantity for each day, to have a minimum amount of Crude available for sale during any day or month or during the term of this Agreement and SELLER will be authorized to make assignment nomination for the sale of the Daily Nominated Quantity at any moment during the term of this Agreement.

Nominations made by SELLER may only be rejected by BUYER under Extenuating Circumstances (as defined below).

The PARTIES accept that BUYER will be held liable for all acts, omissions and activities including all the arrangements for transportation and logistics required for the transportation of the Crude from the Delivery Point to the Atlantic Oil Terminal ("AOT") located in Barranquilla (the "Final Delivery Point").

The PARTIES acknowledge and accept that the Crude purchased by BUYER under this Agreement is purchased for the purpose of exportation.

2. TERM

The Term of this Agreement shall be one (1) year counted as of the date both PARTIES enter into same. The PARTIES may extend the term of the Agreement for another year by entering into an addendum at least thirty (30) calendar days before the expiry of the initial term.

3. CONFIDENTIALITY

Unless otherwise provided by Law or for the fulfillment of this Agreement, the PARTIES to this Agreement represent and warrant and mutually agree that neither of them shall disclose or communicate to anyone who is not a party to this Agreement, nor use or exploit for any purpose, any information related to the transaction foreseen herein, especially with regard to the purchase, transportation and sale of crude which is known to or may be known by them as the result of entering into this Agreement (the "Confidential Information"), and shall make all reasonable efforts to ensure that their employees, directors and related companies abstain from doing so. Notwithstanding the above, the obligation to confidentiality does not apply to:

(i) any information that must be disclosed in order to comply with any applicable legal requirement or legal process, issued by any competent judge or government authority or rules or regulations or policies of any relevant regulatory body (including regulations of any stock exchange or security regulation authority) considering that, if not forbidden by applicable laws, the disclosing PARTY shall notify the other PARTIES with sufficient prior notice regarding a requirement to disclose information by virtue of a court order or administrative procedure in order that the other PARTY may procure a protection warrant regarding such disclosure; or

(ii) information to be submitted to potential investors, advisors and consultants of the PARTY.

Notwithstanding the above, Confidential Information shall not include information that:

- (i) is already known by the receiving PARTY on the date this Agreement is entered into and is not under any confidentiality obligation;
- (ii) is or becomes available to general public without requirement of act or omission by the receiving PARTY or any of its representatives;
- (iii) is independently acquired, after the date this Agreement is entered into, by a third party who states he has the right to disclose such information when it is received by the receiving PARTY, or
- (iv) is developed by the receiving PARTY independently of the Confidential Information received from the disclosing PARTY.

4. PRICING

The Price of the Crude sold by SELLER and purchased by BUYER shall be calculated by multiplying the total volume of Crude sold, by the unit Price established in Clause 5 of this Agreement, without including VAT which shall be invoiced at the applicable legal rate.

As soon as BUYER acquires the qualification of International Trader "*Comercializadora Internacional*" BUYER will provide SELLER the certificate evidencing such qualification in accordance with Colombian legislation. SELLER shall apply the corresponding exemption and not charge VAT on any sale of Crude made on or after the effective date of such certificate.

5. PRICES OF CRUDE

The PARTIES agree that the Price of Crude sold and purchased will be calculated at the Delivery Point according to the following formula for each net barrel delivered (for purposes of this Agreement, net means Net Standard Volume or NSV).

The Price of Crude will be calculated as follows:

$$P = (A + B) + X - T$$

The price must be calculated based on the month the corresponding trucks are loaded. The value of the price for future payment will be that of West Texas Intermediate (WTI) first line in the New York Mercantile Exchange (NYMEX), according to Platts publication / quote. The Marker will be declared by BUYER for any of the following dates, no later than 4:00 pm, Bogotá, Colombia time, on the 15th day of each month. Pursuant to Colombian legislation, if the 15th day of each month is not a working day, the declaration will be made the following working day before 9 am, Bogotá, Colombia time. For all purposes related hereto, Saturdays and Sundays are not considered working days. The Marker options will be the following:

- 1st to 15th of the month in which the loading takes place
- 15th to 30th (or 31st, depending on the month) of the month in which the loading takes place
- Average of the month in which the loading takes place

In which:

- P = Price, expressed in United States Dollars, which BUYER will pay to SELLER for each net barrel of Crude loaded at the Delivery Point.
- A = Reference Value: The Price for future payment of West Texas Intermediate (WTI) first line on the New York Mercantile Exchange (NYMEX), according to Platts publication / quote, corresponding to one of the above-mentioned ranges of declaration dates.
- B = Vasconia Blend: will be calculated as the average of the Vasconia differential according to the publication / quote of Platts Latin American Wire, corresponding to the above-mentioned price ranges.
- X = Is the differential offered by BUYER, expressed in United States Dollars per net Barrel and equivalent to USD \$ 1 per barrel. This amount includes all the costs incurred by BUYER from the Delivery Point to the Final Delivery Point. Such costs include: overhead, marketing, treatment, loading, unloading and final disposition both of the Crude itself, and of the additional components of the blend received, (water, sediment and impurities).
- T = Is the value of the freight of the tanker truck. This is agreed at 0.62 COP/km/gl gross from the Delivery Point to the Final Delivery Point.

BUYER will make its best efforts regarding the negotiation of the tanker truck freight with reliable counterparts in order to attain the best possible freight costs. To such effects, BUYER shall deliver to SELLER, at latter's request, a description of the different efforts made towards obtaining such prices and the different prices offered by the transportation companies, evidencing that BUYER has complied with its contractual obligation.

Each element of the price and the final price will be calculated to three (3) decimal points; the following arithmetical rules will be applied:

- If the fourth decimal is five (5) or higher than five (5), then the third decimal point will be rounded up to the following digit;
- If the fourth decimal is four (4) or lower than four (4), then the third decimal will not change.

6. TECHNICAL CHARACTERISTICS AND CONDITION OF THE CRUDE SOLD

- a) Delivery volume: A maximum estimated volume of 3,650 net barrels of Crude per day + 10%, during the term of the Agreement. In any event, the Daily Nominated Quantity for each day will be determined as established in Clause 1 of this Agreement.

The quantity of Crude sold by SELLER to BUYER will be measured at the Delivery Point. The PARTIES may use an independent laboratory at the Delivery Point to measure the physical properties of the samples. The costs resulting from such inspection services will be exclusively for account of BUYER.

A Truck Way Bill) will be issued for each tanker truck loaded. The PARTIES will make their best efforts to include in the Truck Way Bill all the information regarding volume (gross and net corrected at 60 degrees Fahrenheit), quality (BSW and API), temperature and seal numbers.

- b) Loading Conditions

BUYER undertakes to purchase, receive and load the Crude when the following guaranteed quality specifications are fulfilled:

Crude

Degrees API [Min. 27 – Max 30]; Sulfur Content [Min. 0.416 – Max. 0.55] % Wt; Viscosity @ 50 F [Min. 6.76 – Max 11.97]; BSW [Min. 0.2 – Max 0.5] % vol.

BUYER expressly declares that it is aware of the quality of the Crude being purchased and / or negotiated and thus accepts to hold SELLER harmless from any liability derived from the physical – chemical conditions of the Crude.

7. DELIVERY POINT

The Delivery Point and of transfer of the ownership of the Crude subject to this Agreement will take place:

- When the Crude passes from the inlet flange to the tank of the tanker truck being loaded.

The PARTIES agree that BUYER shall enter into all the transportation and logistics contracts required for the transportation of the Crude from Delivery Point to the Final Delivery Point. In this respect, BUYER shall enter into all the agreements that may be necessary with the shipper who is to load and unload and transport the Crude from the Delivery Point to the Final Delivery Point. BUYER shall ensure that the shipper complies with all the applicable regulations relating to the transportation of crude oil in Colombia and all the insurance requirements set forth by the Colombian authorities for such purpose.

Once ownership and risk have passed to BUYER, SELLER shall not be held liable by BUYER or by any third party for damages or accidents that may occur during transportation of the Crude, including without limitation crude oil spills that may occur during transportation of the Crude to the Final Delivery Point. Consequently, any loss of Crude that may occur after loading at the Delivery Point will be entirely assumed by BUYER.

The Net Sales Value (NSV) of the Crude will be corrected to meet standard conditions (60° F).

8. DELIVERY AND OWNERSHIP

The Crude will be loaded at the Delivery Point. The Crude's ownership and risk will pass from SELLER to BUYER when the Crude passes the inlet flange to the tank of the tanker truck being loaded. All the Crude delivered to BUYER (or to the entity designated by BUYER to transport the Crude) and duly loaded will be deemed transferred to BUYER and therefore SELLER will be entitled to issue the corresponding invoice and BUYER will be obligated to pay the delivered amounts of Crude. Any loss suffered after the ownership and risk are transferred to BUYER pursuant to this Clause 8 will be directly assumed by BUYER and BUYER shall have no claim or appeal against SELLER and shall hold SELLER harmless from any loss or damage caused.

The Crude and its derivatives shall not be re-sold or supplied, directly nor indirectly, to any country, territory or company in which such sale or supply is a breach of applicable law, regulations and / or rulings.

9. LIABILITY

BUYER shall be liable for the final destination and disposition given to the Crude. In no case shall SELLER be liable before third parties to whom BUYER has sold the Crude.

Neither of the PARTIES shall be liable before the other PARTY for any indirect or consequential damage.

Additionally, BUYER undertakes to release, hold harmless and indemnify SELLER for any damage, legal breach, crude spill and in general, for any claim or damage that may arise after delivery of the Crude to BUYER at the Delivery Point, even resulting from the transportation of the Crude from the Delivery Point to the Final Delivery Point and from the subsequent sale of the Crude by BUYER.

10. FREIGHT

If the PARTIES agree to designate a Delivery Point other than the one stipulated in Clause 7 of this Agreement, they must enter into an addendum describing how transportation costs for such events will be assumed.

In the event that a change of price and conditions for freight is agreed, the PARTIES will meet, discuss and agree upon a new price. In the event that the PARTIES fail to reach an agreement in a period of ten (10) calendar days, they may terminate the agreement by giving prior written notice of at least thirty (30) days. The termination does not generate any indemnity or payment of any kind by either of the PARTIES, except for outstanding invoices and / or sales that have been made and which shall be paid independently of the termination.

Nevertheless, the PARTIES may mutually agree to review the freight price at any time due to changing market conditions that may affect the viability of the operation.

Such freight price negotiations will be made bearing in mind that BUYER has a contractual obligation to employ its best efforts to obtain the best possible freight costs.

11. DELIVERY VOLUMES

SELLER may sell to BUYER a total amount of 3,650 barrels of crude + 10% per day during the term of the Agreement at the Delivery Point. BUYER will purchase and take from the Delivery Point the Daily Nominated Quantity that was nominated in accordance with Clause 1 except when Extenuating Circumstances occur.

12. DELIVERY PROGRAM

SELLER will establish the Daily Nominated Quantity for any day in the manner described in Clause 1 of this Agreement. Except in the case of Extenuating Circumstances (as defined in Clause 22) SELLER shall deliver the Daily Nominated Quantity that was nominated.

Except for Extenuating Circumstances, BUYER shall fully comply with the obligation of purchasing and loading the accepted Daily Nominated Quantity. BUYER shall immediately notify SELLER in writing if such Extenuating Circumstances occur, whereupon SELLER will be free to dispose of the Crude. SELLER will re-establish supply once BUYER returns operations to normal conditions. SELLER will reestablish supply once BUYER's operations return to normal. If BUYER's inability to receive the Crude lasts more than thirty (30) calendar days, SELLER may consider the Agreement unilaterally terminated without application of any sanctions, indemnities or compensation for the account of either of the PARTIES.

In the event that SELLER is not able to supply the Crude nominated in the Daily Nominated Quantity due to Extenuating Circumstances, SELLER shall immediately inform BUYER in writing of such circumstances and in any event shall do everything possible to report the issue within a maximum term of forty-eight (48) hours. Once the emergency has been resolved, SELLER will announce the date for reactivation of the nominations and sales of Crude. If the lack of delivery of the Crude included in the Daily Nominated Quantity that has been nominated in accordance with Clause 1 of this Agreement extends beyond a term of thirty (30) calendar days, BUYER may consider the Agreement unilaterally terminated without this generating any sanctions, indemnities or compensation for the account of either of the PARTIES.

13. INVOICING AND TERMS OF PAYMENT

BUYER shall make weekly payments for the received amount of Crude, in accordance with the Agreement, as follows:

SELLER shall issue a weekly invoice and deliver it to BUYER's office. The value to be invoiced will be the result of multiplying 80% of the quantity of net barrels received in one week by the price of each barrel loaded, using as a reference the average provisional price of Vasconia medium Blend according to Platts Latin American Wire publication / quote during the week before the week in which the tanker trucks were loaded.

Each provisional payment shall be made upon BUYER receiving in its office in Colombia the following original documents:

- Commercial Invoice pursuant to the terms and conditions established herein.
- Copies of the Truck Way Bill duly signed by the driver of the tank trucker and stamped by SELLER.
- Certificate of Origin for the weekly volumes.

The Barrels pending payment shall be taken into account when payments are reconciled at the end of each month.

Payments shall be reconciled as soon as all the barrels of Crude loaded during each month that have to be reconciled have been completely loaded at the Delivery Point.

Payments shall be made upon BUYER receiving in its office in Colombia the following original documents:

- Commercial Invoice for the value resulting from the monthly barrels of Crude delivered multiplied by the price of the Crude calculated as indicated in Clause 4 herein, minus the invoices issued by SELLER for the period.
- The Price of the commercial invoice shall be as mentioned in Clause 4 for all the barrels sold monthly.
- Complete copies of the Truck Way Bills.

All the loaded Volumes and price charged during the month shall be reconciled.

NO PAYMENTS WILL BE MADE UNTIL THE CRUDE HAS BEEN LOADED AT THE DELIVERY POINT.

If BUYER has any debts with SELLER for volumes of Crude delivered in any month, the total amount shall be paid no later than the 10th day of the following month.

Payments made as the result of the purchase and sale of the Crude may be made by BUYER or its parent company, Gunvor S.A.

The currency to be used in this Agreement will be Dollars of the United States and payments shall be made by electronic wire transfer to the account specified below or any other determined by SELLER in the corresponding invoice.

Correspondent Bank: HSBC Bank USA
 Swift Code: MRMDUS33
 ABA No.021001088

Consignee: HSBC Bank Bermuda Limited
 Swift Code: BBDA BMHM

Hamilton, Bermuda
Name of Beneficiary: Gran Tierra Energy Colombia Ltd.
Account of Beneficiary: No. 011-029527-501
Address of Beneficiary: 300, 625 -11 Avenue SW
Calgary, Alberta, T2R 0E1

14. STANDBY LETTER OF CREDIT

For the purpose of securing payment obligations, BUYER undertakes to obtain an irrevocable Standby Letter of Credit ("SLOC") issued by a financial institution approved by SELLER for an insured value of USD \$ 4,000,000. Such SLOC shall be valid for one (1) year counted as of the date of entering into this Agreement and shall be duly issued and in force within 10 days following the date of entering into this Agreement.

The SLOC shall remain in force during the term of the Agreement therefore, in the event that the Agreement is extended, the SLOC shall also be extended or a new letter of credit for a term equal to that of the extension(s) shall be issued.

15. NATURE OF THE AGREEMENT

The PARTIES expressly agree and accept that this Agreement does not constitute a labor contract or a labor relationship between SELLER and BUYER's personnel in charge of fulfilling the purpose of this Agreement.

Similarly, the PARTIES expressly establish that this Agreement does not constitute a labor contract or a labor relationship between BUYER and SELLER's personnel in charge of fulfilling the purpose of this Agreement.

According to the above, it shall be understood that the PARTIES are independent companies and are not agents, representatives, employees or intermediaries of the other PARTY with regard to the personnel employed for the execution of this Agreement.

It is expressly understood and stipulated that each and every officer, technician and other personnel appointed by each PARTY to fulfill this Agreement has a specific relationship with that PARTY, thus it is up to each of such PARTIES to make the payments associated with fees, salaries and legal and extra-legal benefits, indemnities, overtime, social benefits, allowances, insurance, etc. and in general shall fulfill all the payments for affiliations and contributions to the Integrated Social Security System and other parafiscal payments (ICBF, SENA, Family Compensation Funds, etc.), set forth in the Colombian legislation.

If, due to a breach of any of the above-mentioned legal and contractual obligations, or due to a breach of Article 34 of the Colombian Substantive Labor Code with its additions and amendments, or if by a court ruling it is determined that the other PARTY shall be jointly and severally liable for the payments and indemnities that correspond to the other PARTY, with regard to one or several employees, the liable PARTY shall reimburse the other PARTY all the amounts it may have paid within three (3) working days following the date of payment.

16. TAXES

Each of the PARTIES shall be liable for the payment of its corresponding taxes in accordance with the Colombian legislation.

17. APPLICABLE LAW

This Agreement shall be governed and construed in accordance with the Laws of the Republic of Colombia.

18. ARBITRATION

The PARTIES agree that in the event of a conflict or dispute in relation to any aspect of this Agreement, they will attempt to resolve their differences by mutual agreement, for which they will have a term of thirty (30) calendar days. If upon expiry of this period the PARTIES have failed to reach an agreement, the matter will be referred to Arbitration, which will be held in the Arbitration and Conciliation Center of Bogotá Chamber of Commerce according to the following rules:

- (i) The Arbitration Tribunal shall be composed of three (3) arbitrators who will be Colombian lawyers, appointed by mutual agreement by the PARTIES, or, if they fail to reach an agreement, by the Bogota Chamber of Commerce.
- (ii) The seat of the Tribunal shall be the city of Bogotá, at the Arbitration and Conciliation Center of Bogotá Chamber of Commerce.
- (iii) The internal organization of the Tribunal will be subject to the rules of the Arbitration and Conciliation Center of Bogotá Chamber of Commerce.
- (iv) The Tribunal shall decide according to law.
- (v) The costs of the Tribunal shall be determined according to the Rules of the Arbitration and Conciliation Center of Bogotá Chamber of Commerce.

19. AMENDMENTS

This Agreement contains all the agreements between the PARTIES regarding the matters which constitute its purpose and it repeals any prior, written or oral agreement, contract and understanding. No amendment, change or extension of this Agreement shall be binding unless it is in writing and is signed by the PARTIES.

20. ASSIGNMENT

Neither of the PARTIES may assign, in whole or in part, this Agreement or the rights, liabilities and obligations of the same without the prior written acceptance of the other PARTY (which acceptance shall not be unreasonably denied).

In the event of assignment, both the assignor and the assignee will be jointly and severally liable for all obligations arising herefrom.

21. NOTICES

The PARTIES establish the following addresses to which any information may be sent or communicated:

GRAN TIERRA ENERGY COLOMBIA LTD

Calle 113 No. 7 – 80 Piso 17

Torre AR

Bogotá - Colombia

GUNVOR COLOMBIA SAS (BUYER):
CARRERA 7 #83 -29
OFC 304 CENTRO EMPRESARIAL LA CABRERA
BOGOTÁ - COLOMBIA

Changes of domicile or representatives of the PARTIES shall be notified to the other PARTY in writing within five (5) business days following the date of the change; otherwise, any communication addressed to the last registered address or name of the latest recorded representative shall have identical consequences in law.

22. FORCE MAJEURE, ACT OF GOD, ACTS OF THIRD PARTIES AND ACTS OF THE AUTHORITIES.

The PARTIES shall comply with all the obligations arising from this Agreement, except in cases of *force majeure*, acts of God, acts of third parties or acts of the authorities (hereinafter "Extenuating Circumstances") which shall be duly proven.

Force Majeure and acts of God are understood to be unforeseen events that cannot be resisted and that the PARTIES cannot predict, such as shipwrecks, earthquakes, floods, etc. that prevent either of the PARTIES from meeting their obligations under the Agreement.

Acts of third parties are those acts that prevent compliance in whole or in part with this Agreement and that in addition the PARTIES do not have the legal duty to confront, such as revolts, rebellions, terrorist actions and civil unrest.

Acts of the authorities are activities or decisions stemming from the competent authorities, whether local, regional or national that substantially affects the performance of the obligations arising from this Agreement.

It is understood that Extenuating Circumstances occur under circumstances that are beyond the control of the PARTIES, despite the fact that the PARTIES may have taken the necessary corrective measures that seek to eliminate the causes of the delay or the exclusion.

If as a result of an Extenuating Circumstance, a PARTY is unable to comply in whole or in part with its obligations under this Agreement, the obligations of the PARTY giving such notice, as and to the extent that such obligations may be affected by an Extenuating Circumstance, will be suspended while any inability to meet them persists during the reasonable time that may be required in order that the PARTY can once again meet its obligations, but not for a longer period.

The PARTY that invokes an Extenuating Circumstance shall notify the other PARTY regarding the Extenuating Circumstance as soon as reasonably practicable after the occurrence of the relevant facts and shall keep the other PARTY informed of all aspects. Such notice shall include reasonably full details of the Extenuating Circumstance and the measures that the affected PARTY intends to take to mitigate and remedy the Extenuating Circumstance and shall also contain an estimate of the time period that the PARTY considers will be required to remedy the Extenuating Circumstance.

The affected PARTY shall use reasonable diligence to mitigate and remove or overcome the Extenuating Circumstance as soon as possible in a commercially reasonable manner but will not be obliged to settle any labor dispute except in terms that are acceptable to therefor. All of these disputes shall be handled with discretion by the affected PARTY.

23. TERMINATION OF THE AGREEMENT

In addition to the other causes of termination described herein, either of the PARTIES may terminate this Agreement, by written notice, as a result of any of the following events:

- a) By unilateral decision of either of the PARTIES to terminate this Agreement before the expiry of its term, giving prior written notice to the other PARTY of ninety (90) working days.

The unilateral termination of this Agreement does not relieve the PARTIES of their undertakings and obligations contracted herein with respect to the confidentiality of the information.
- b) By voluntary or forced dissolution or liquidation of either of the PARTIES;
- c) By the financial insolvency of either of the PARTIES, which shall be presumed once the above-mentioned PARTY incurs in cessation of payments of its obligations or the total or partial attachment of its property.
- d) As a result of the material breach of any of the substantial obligations of the PARTIES under this Agreement.
- e) If either of the PARTIES is subject to receivership.
- f) If either of the PARTIES loses its licenses and the administrative authorizations which give it the right to meet the purpose of this Agreement.
- g) Due to the gross negligence or willful misconduct of the PARTIES in the execution of the Agreement.
- h) Breach by the BUYER (and or conveyor) concerning the HSE policies of the SELLER.
- i) Inability to collect or deliver the volumes of Crude agreed under this Agreement within the terms and times agreed upon between the PARTIES.

If any of the events referred to in this clause occurs, either of the PARTIES may terminate the Agreement within the following thirty (30) calendar days (with the exception of the case referred to in subsection a) of this clause), having the right to exercise the legal actions required to obtain any indemnity in its favor in accordance with Colombian law. For purposes of clarity, it is agreed that any claim or pretension arising from a breach of this Agreement occurring prior to the termination of this Agreement will survive such termination.

Each of the PARTIES undertakes to return to the other, within five (5) days following the notice of termination of the Agreement, if applicable, all documents (in written or electronic form), files and other materials that had been delivered in fulfillment of the purpose of this Agreement.

24. STATEMENT OF LEGITIMACY AND ORIGIN OF THE RESOURCES

By entering into this Agreement, each of the PARTIES declares that it has not engaged in illegal activities or operations, and

- a- That the resources do not originate, directly or indirectly, from an illegal activity provided as such in Colombian law, especially in the Colombian Criminal Code, in supra-legal or international regulations or other regulations that add to them or change them, particularly with respect to activities related to drug trafficking or the laundering of assets.
- b- That neither of the companies that enter into this Agreement, nor its representatives, partners, officials or employees is included by the Office of Foreign Assets Control of the Department of the

Treasury of the United States of America in the list of Specially Designated Narcotics Traffickers referred to by the Department of the Treasury ("Clinton List") or any other similar list issued by any Government.

- c- That neither of the companies that are a PARTY to this Agreement, nor its representatives, partners, officers or employees are involved in processes related to illegal activities such as the transport, traffic, processing or negotiation of illegal materials, laundering of assets and / or related activities, terrorism and or similar activities.
- d- That neither of the PARTIES to this Agreement nor its representatives, partners, officers or employees are contributors and / or are linked to armed groups or groups whose conduct is classified as terrorist activities.

25. SEVERABILITY

If at any time one or more provisions of this Agreement is or is established as being illegal, invalid or unenforceable under applicable laws of any jurisdiction, neither the legality, validity or enforceability of the other provisions of the Agreement, nor the legality, validity or enforceability of such provision under the laws of any other jurisdiction shall be affected thereby. Without limiting the foregoing, the PARTIES shall negotiate in good faith to agree upon the terms of a mutually satisfactory provision to replace the invalid and unenforceable provision.

26. HEALTH AND SAFETY

BUYER shall strictly observe and comply (and shall ensure that the conveyor also complies) with the regulations currently in force regarding industrial safety and occupational health, whether they be of a legal or administrative nature.

Furthermore, BUYER shall observe and follow the instructions (and shall ensure that the conveyor does same) that SELLER issues at any time with respect to the fulfillment of the Agreement and the loading of the Crude.

In consideration of the foregoing, BUYER shall strictly observe (and shall ensure that the conveyor also observes) SELLER's HSE policies (which are attached to this Agreement or which may be submitted in writing to BUYER in the future) and any breach of such policies will lead to the termination of the Agreement. In addition, in the event that SELLER verifies that its HSE policies are not being observed, it may determine not to deliver Crude until BUYER complies with such policies.

27. ANTI-CORRUPTION

Neither BUYER nor its related companies have made, offered or authorized, nor will they make, offers, nor have they authorized any payment, gift, promise or other advantages, related in any way with any of their contracts or operations or matters that are material to this Agreement, whether directly or indirectly through any person or other entity, to or for the use or benefit of any public official (i.e. anyone in legislative, administrative or judicial office, including any person employed by or acting on behalf of a public entity, a public company or a public international organization) or any political party or official of a political party or candidate for office, when such payment, gift or pledge violates:

- (i) The laws / regulations of the country of operations;
- (ii) The laws / regulations of the country of incorporation of the PARTY and the parent company and ultimate beneficiary of such PARTY (or the headquarters of its business);
- (iii) Foreign Corrupt Practices Act (FCPA - U.S.A.); or

- (iv) The principles outlined in the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions, signed in Paris on December 17, 1997, which entered into force on February 15, 1999, and the Commentaries on the Convention.

28. WAIVER

No omission or delay by either of the PARTIES in the exercise of its rights under this Agreement will operate as a waiver thereof, or the single or partial exercise by either of the PARTIES of such right will prevent the further exercise or other exercise thereof or of other rights it may have.

29. CLAIMS

Claims between the PARTIES with respect to the quality and the quantity of the Crude or related to payments under the Agreement shall be delivered to the other PARTY with available support documentation within ninety (90) days following the date of loading of the Crude at the Delivery Point. The PARTY which receives the claim shall not be held liable for any claims received after such date.

30. ENFORCEABILITY

The PARTIES expressly established that this Agreement lends right of enforcement because it is a clear, explicit and enforceable obligation pursuant to the provisions of the Colombian Code of Civil Procedure.

31. LANGUAGE

This Agreement is drafted in Spanish and constitutes the only form of the obligations between the PARTIES. Any translation hereof into another language can only be used for reference purposes between the PARTIES and shall at no time affect the meaning or interpretation of the version in Spanish.

In witness whereof, this Agreement is signed in two (2) counterparts in Bogotá D.C., on the third (3rd) day of the month of December of the year two thousand twelve (2012).

SELLER: Gran Tierra Energy Colombia Ltd. BUYER: GUNVOR COLOMBIA S.A.S.

/s/ Alejandra Escobar Herrera /s/ Jaime Alejandro Hoyos Juliao

Alejandra Escobar Herrera **Jaime Alejandro Hoyos Juliao**
Legal Representative **Legal Representative**

/s/ Manuel Antonio Buitrago Vives

Manuel Antonio Buitrago Vives
Legal Representative



GUNVOR COLOMBIA SAS

Carrera 7 No. 83-29, Oficina 304 Bogotá, Colombia
Phone +57-1 - 6227978 / 6364768

Exhibit 10.70

Date: December 3, 2012

COSTAYACO CRUDE OIL SALES / PURCHASE AGREEMENT

This **CRUDE OIL SALES / PURCHASE AGREEMENT** (hereinafter the "Agreement") is entered into on December 3, 2012 and shall be in effect as of this date, by and between PETROLIFERA PETROLEUM (COLOMBIA) LIMITED a limited liability company organized under the Laws of Cayman Islands, acting through its duly registered Colombian branch (hereinafter the "SELLER"), jointly represented by Alejandra Escobar Herrera, identified with Citizenship Card No. 52.646.943 and Manuel Antonio Buitrago Vives, identified with Citizenship Card No 72.191.666, duly authorized to enter into this Agreement pursuant to the Certificate of Incorporation and Legal Representation attached hereto, issued by the Chamber of Commerce, and GUNVOR COLOMBIA SAS, a company organized under the Laws of the Republic of Colombia (hereinafter the "BUYER"), represented by Jaime Alejandro Hoyos Juliao, bearer of Citizenship Card No. 80.082.474, duly authorized to enter into this Agreement pursuant to the vote in writing dated November 30, 2012 of the sole shareholder of Gunvor SAS, attached hereto. SELLER and BUYER shall be hereinafter individually referred to as a "PARTY", and collectively as the "PARTIES".

RECITALS:

1. **WHEREAS** SELLER is a company whose main purpose is exploring and producing crude oil in the Republic of Colombia.
2. **WHEREAS** SELLER is a party to the Chaza E&P Agreement entered into with the ANH (*Agencia Nacional de Hidrocarburos*), in the area located in the Department of Putumayo, Republic of Colombia.
3. **WHEREAS** SELLER is interested in selling the crude oil produced in Campo Costayaco (the "Crude"), located in the area of the Chaza E&P Agreement.
4. **WHEREAS** BUYER is a company whose main purpose is the purchase and subsequent sale of crude oil.
5. **WHEREAS** SELLER is interested in selling and BUYER is interested in purchasing SELLER's Crude, produced in *Campo Costayaco* located in Putumayo, Colombia, in an estimated amount of 3,650 BPD +10%.

NOW THEREFORE, in consideration of the premises and of the representations, warranties, pacts, agreements and mutual commitments established herein or those referred to herein, the PARTIES agree as follows:

1. PURPOSE

Subject to and pursuant to the terms and conditions herein, SELLER may sell and deliver, and BUYER may purchase and load when SELLER so nominates, up to a maximum amount of 3,650 barrels of crude + 10% per day during the term of the Agreement. SELLER undertakes to sell and deliver the Crude at the Delivery Point (term defined in Clause 7 hereunder) in accordance with the technical specifications and conditions established herein. BUYER agrees to purchase and load the Crude at the Delivery Point and to pay SELLER the price agreed upon for the nominal volume received from SELLER at the Delivery Point, in accordance with the price conditions established in the Agreement.

SELLER shall make his best effort to deliver to BUYER no later than the last day of each month, an estimation of the amount of Crude it expects to deliver on a daily basis during the following month. Notwithstanding the aforesaid, SELLER, with prior notice of not less than 48 hours before any day that SELLER chooses to sell the Crude to BUYER, shall nominate the quantity of Crude (hereinafter the "Daily Nominated Quantity") that will be sold to SELLER at the Delivery Point on the day stated in such nomination. SELLER shall not be obliged to nominate a Daily Nominated Quantity for each day, to have a minimum amount of Crude available for sale during any day or month or during the term of this Agreement and SELLER will be authorized to make assignment nomination for the sale of the Daily Nominated Quantity at any moment during the term of this Agreement.

Nominations made by SELLER may only be rejected by BUYER under Extenuating Circumstances (as defined below).

The PARTIES accept that BUYER will be held liable for all acts, omissions and activities including all the arrangements for transportation and logistics required for the transportation of the Crude from the Delivery Point to the Atlantic Oil Terminal ("AOT") located in Barranquilla (the "Final Delivery Point").

The PARTIES acknowledge and accept that the Crude purchased by BUYER under this Agreement is purchased for the purpose of exportation.

2. TERM

The Term of this Agreement shall be one (1) year counted as of the date both PARTIES enter into same. The PARTIES may extend the term of the Agreement for another year by entering into an addendum at least thirty (30) calendar days before the expiry of the initial term.

3. CONFIDENTIALITY

Unless otherwise provided by Law or for the fulfillment of this Agreement, the PARTIES to this Agreement represent and warrant and mutually agree that neither of them shall disclose or communicate to anyone who is not a party to this Agreement, nor use or exploit for any purpose, any information related to the transaction foreseen herein, especially with regard to the purchase, transportation and sale of crude which is known to or may be known by them as the result of entering into this Agreement (the "Confidential Information"), and shall make all reasonable efforts to ensure that their employees, directors and related companies abstain from doing so. Notwithstanding the above, the obligation to confidentiality does not apply to:

- (i) any information that must be disclosed in order to comply with any applicable legal requirement or legal process, issued by any competent judge or government authority or rules or regulations or policies of any relevant regulatory body (including regulations of any stock exchange or security regulation authority) considering that, if not forbidden by applicable laws, the disclosing PARTY shall notify the other PARTIES with sufficient prior notice regarding a requirement to disclose information by virtue of a court order or administrative procedure in order that the other PARTY may procure a protection warrant regarding such disclosure; or
- (ii) information to be submitted to potential investors, advisors and consultants of the PARTY.

Notwithstanding the above, Confidential Information shall not include information that:

- (i) is already known by the receiving PARTY on the date this Agreement is entered into and is not under any confidentiality obligation;
- (ii) is or becomes available to general public without requirement of act or omission by the receiving PARTY or any of its representatives;
- (iii) is independently acquired, after the date this Agreement is entered into, by a third party who states he has the right to disclose such information when it is received by the receiving PARTY, or
- (iv) is developed by the receiving PARTY independently of the Confidential Information received from the disclosing PARTY.

4. PRICING

The Price of the Crude sold by SELLER and purchased by BUYER shall be calculated by multiplying the total volume of Crude sold, by the unit Price established in Clause 5 of this Agreement, without including VAT which shall be invoiced at the applicable legal rate.

As soon as BUYER acquires the qualification of International Trader "*Comercializadora Internacional*" BUYER will provide SELLER the certificate evidencing such qualification in accordance with Colombian legislation. SELLER shall apply the corresponding exemption and not charge VAT on any sale of Crude made on or after the effective date of such certificate.

5. PRICES OF CRUDE

The PARTIES agree that the Price of Crude sold and purchased will be calculated at the Delivery Point according to the following formula for each net barrel delivered (for purposes of this Agreement, net means Net Standard Volume or NSV).

The Price of Crude will be calculated as follows:

$$P = (A + B) + X - T$$

The price must be calculated based on the month the corresponding trucks are loaded. The value of the price for future payment will be that of West Texas Intermediate (WTI) first line in the New York Mercantile Exchange (NYMEX), according to Platts publication / quote. The Marker will be declared by BUYER for any of the following dates, no later than 4:00 pm, Bogotá, Colombia time, on the 15th day of each month. Pursuant to Colombian legislation, if the 15th day of each month is not a working day, the declaration will be made the following working day before 9 am, Bogotá, Colombia time. For all purposes related hereto, Saturdays and Sundays are not considered working days. The Marker options will be the following:

- 1st to 15th of the month in which the loading takes place
- 15th to 30th (or 31st, depending on the month) of the month in which the loading takes place
- Average of the month in which the loading takes place

In which:

- P = Price, expressed in United States Dollars, which BUYER will pay to SELLER for each net barrel of Crude loaded at the Delivery Point.
- A = Reference Value: The Price for future payment of West Texas Intermediate (WTI) first line on the New York Mercantile Exchange (NYMEX), according to Platts publication / quote, corresponding to one of the above-mentioned ranges of declaration dates.
- B = Vasconia Blend: will be calculated as the average of the Vasconia differential according to the publication / quote of Platts Latin American Wire, corresponding to the above-mentioned price ranges.
- X = Is the differential offered by BUYER, expressed in United States Dollars per net Barrel and equivalent to USD \$ 1 per barrel. This amount includes all the costs incurred by BUYER from the Delivery Point to the Final Delivery Point. Such costs include: overhead, marketing, treatment, loading, unloading and final disposition both of the Crude itself, and of the additional components of the blend received, (water, sediment and impurities).
- T = Is the value of the freight of the tanker truck. This is agreed at 0.62 COP/km/gal gross from the Delivery Point to the Final Delivery Point.

BUYER will make its best efforts regarding the negotiation of the tanker truck freight with reliable counterparts in order to attain the best possible freight costs. To such effects, BUYER shall deliver to SELLER, at latter's request, a description of the different efforts made towards obtaining such prices and the different prices offered by the transportation companies, evidencing that BUYER has complied with its contractual obligation.

Each element of the price and the final price will be calculated to three (3) decimal points; the following arithmetical rules will be applied:

- If the fourth decimal is five (5) or higher than five (5), then the third decimal point will be rounded up to the following digit;
- If the fourth decimal is four (4) or lower than four (4), then the third decimal will not change.

6. TECHNICAL CHARACTERISTICS AND CONDITION OF THE CRUDE SOLD

- a) Delivery volume: A maximum estimated volume of 3,650 net barrels of Crude per day + 10%, during the term of the Agreement. In any event, the Daily Nominated Quantity for each day will be determined as established in Clause 1 of this Agreement.

The quantity of Crude sold by SELLER to BUYER will be measured at the Delivery Point. The PARTIES may use an independent laboratory at the Delivery Point to measure the physical properties of the samples. The costs resulting from such inspection services will be exclusively for account of BUYER.

A Truck Way Bill) will be issued for each tanker truck loaded. The PARTIES will make their best efforts to include in the Truck Way Bill all the information regarding volume (gross and net corrected at 60 degrees Fahrenheit), quality (BSW and API), temperature and seal numbers.

- b) Loading Conditions

BUYER undertakes to purchase, receive and load the Crude when the following guaranteed quality specifications are fulfilled:

Crude

Degrees API [Min. 27 – Max 30]; Sulfur Content [Min. 0.416 – Max. 0.55] % Wt; Viscosity @ 50 F [Min. 6.76 – Max 11.97]; BSW [Min. 0.2 – Max 0.5] % vol.

BUYER expressly declares that it is aware of the quality of the Crude being purchased and / or negotiated and thus accepts to hold SELLER harmless from any liability derived from the physical – chemical conditions of the Crude.

7. DELIVERY POINT

The Delivery Point and of transfer of the ownership of the Crude subject to this Agreement will take place:

- When the Crude passes from the inlet flange to the tank of the tanker truck being loaded.

The PARTIES agree that BUYER shall enter into all the transportation and logistics contracts required for the transportation of the Crude from Delivery Point to the Final Delivery Point. In this respect, BUYER shall enter into all the agreements that may be necessary with the shipper who is to load and unload and transport the Crude from the Delivery Point to the Final Delivery Point. BUYER shall ensure that the shipper complies with all the applicable regulations relating to the transportation of crude oil in Colombia and all the insurance requirements set forth by the Colombian authorities for such purpose.

Once ownership and risk have passed to BUYER, SELLER shall not be held liable by BUYER or by any third party for damages or accidents that may occur during transportation of the Crude, including without limitation crude oil spills that may occur during transportation of the Crude to the Final Delivery Point. Consequently, any loss of Crude that may occur after loading at the Delivery Point will be entirely assumed by BUYER.

The Net Sales Value (NSV) of the Crude will be corrected to meet standard conditions (60° F).

8. DELIVERY AND OWNERSHIP

The Crude will be loaded at the Delivery Point. The Crude's ownership and risk will pass from SELLER to BUYER when the Crude passes the inlet flange to the tank of the tanker truck being loaded. All the Crude delivered to BUYER (or to the entity designated by BUYER to transport the Crude) and duly loaded will be deemed transferred to BUYER and therefore SELLER will be entitled to issue the corresponding invoice and BUYER will be obligated to pay the delivered amounts of Crude. Any loss suffered after the ownership and risk are transferred to BUYER pursuant to this Clause 8 will be directly assumed by BUYER and BUYER shall have no claim or appeal against SELLER and shall hold SELLER harmless from any loss or damage caused.

The Crude and its derivatives shall not be re-sold or supplied, directly nor indirectly, to any country, territory or company in which such sale or supply is a breach of applicable law, regulations and / or rulings.

9. LIABILITY

BUYER shall be liable for the final destination and disposition given to the Crude. In no case shall SELLER be liable before third parties to whom BUYER has sold the Crude.

Neither of the PARTIES shall be liable before the other PARTY for any indirect or consequential damage.

Additionally, BUYER undertakes to release, hold harmless and indemnify SELLER for any damage, legal breach, crude spill and in general, for any claim or damage that may arise after delivery of the Crude to BUYER at the Delivery Point, even resulting from the transportation of the Crude from the Delivery Point to the Final Delivery Point and from the subsequent sale of the Crude by BUYER.

10. FREIGHT

If the PARTIES agree to designate a Delivery Point other than the one stipulated in Clause 7 of this Agreement, they must enter into an addendum describing how transportation costs for such events will be assumed.

In the event that a change of price and conditions for freight is agreed, the PARTIES will meet, discuss and agree upon a new price. In the event that the PARTIES fail to reach an agreement in a period of ten (10) calendar days, they may terminate the agreement by giving prior written notice of at least thirty (30) days. The termination does not generate any indemnity or payment of any kind by either of the PARTIES, except for outstanding invoices and / or sales that have been made and which shall be paid independently of the termination.

Nevertheless, the PARTIES may mutually agree to review the freight price at any time due to changing market conditions that may affect the viability of the operation.

Such freight price negotiations will be made bearing in mind that BUYER has a contractual obligation to employ its best efforts to obtain the best possible freight costs.

11. DELIVERY VOLUMES

SELLER may sell to BUYER a total amount of 3,650 barrels of crude + 10% per day during the term of the Agreement at the Delivery Point. BUYER will purchase and take from the Delivery Point the Daily Nominated Quantity that was nominated in accordance with Clause 1 except when Extenuating Circumstances occur.

12. DELIVERY PROGRAM

SELLER will establish the Daily Nominated Quantity for any day in the manner described in Clause 1 of this Agreement. Except in the case of Extenuating Circumstances (as defined in Clause 22) SELLER shall deliver the Daily Nominated Quantity that was nominated.

Except for Extenuating Circumstances, BUYER shall fully comply with the obligation of purchasing and loading the accepted Daily Nominated Quantity. BUYER shall immediately notify SELLER in writing if such Extenuating Circumstances occur, whereupon SELLER will be free to dispose of the Crude. SELLER will re-establish supply once BUYER returns operations to normal conditions. SELLER will reestablish supply once BUYER's operations return to normal. If BUYER's inability to receive the Crude lasts more than thirty (30) calendar days, SELLER may consider the Agreement unilaterally terminated without application of any sanctions, indemnities or compensation for the account of either of the PARTIES.

In the event that SELLER is not able to supply the Crude nominated in the Daily Nominated Quantity due to Extenuating Circumstances, SELLER shall immediately inform BUYER in writing of such circumstances and in any event shall do everything possible to report the issue within a maximum term of forty-eight (48) hours. Once the emergency has been resolved, SELLER will announce the date for reactivation of the nominations and sales of Crude. If the lack of delivery of the Crude included in the Daily Nominated Quantity that has been nominated in accordance with Clause 1 of this Agreement extends beyond a term of thirty (30) calendar days, BUYER may consider the Agreement unilaterally terminated without this generating any sanctions, indemnities or compensation for the account of either of the PARTIES.

13. INVOICING AND TERMS OF PAYMENT

BUYER shall make weekly payments for the received amount of Crude, in accordance with the Agreement, as follows:

SELLER shall issue a weekly invoice and deliver it to BUYER's office. The value to be invoiced will be the result of multiplying 80% of the quantity of net barrels received in one week by the price of each barrel loaded, using as a reference the average provisional price of Vasconia medium Blend according to Platts Latin American Wire publication / quote during the week before the week in which the tanker trucks were loaded.

Each provisional payment shall be made upon BUYER receiving in its office in Colombia the following original documents:

- Commercial Invoice pursuant to the terms and conditions established herein.
- Copies of the Truck Way Bill duly signed by the driver of the tank trucker and stamped by SELLER.

- Certificate of Origin for the weekly volumes.

The Barrels pending payment shall be taken into account when payments are reconciled at the end of each month.

Payments shall be reconciled as soon as all the barrels of Crude loaded during each month that have to be reconciled have been completely loaded at the Delivery Point.

Payments shall be made upon BUYER receiving in its office in Colombia the following original documents:

- Commercial Invoice for the value resulting from the monthly barrels of Crude delivered multiplied by the price of the Crude calculated as indicated in Clause 4 herein, minus the invoices issued by SELLER for the period.
- The Price of the commercial invoice shall be as mentioned in Clause 4 for all the barrels sold monthly.
- Complete copies of the Truck Way Bills.

All the loaded Volumes and price charged during the month shall be reconciled.

NO PAYMENTS WILL BE MADE UNTIL THE CRUDE HAS BEEN LOADED AT THE DELIVERY POINT.

If BUYER has any debts with SELLER for volumes of Crude delivered in any month, the total amount shall be paid no later than the 10th day of the following month.

Payments made as the result of the purchase and sale of the Crude may be made by BUYER or its parent company, Gunvor S.A.

The currency to be used in this Agreement will be Dollars of the United States and payments shall be made by electronic wire transfer to the account specified below or any other determined by SELLER in the corresponding invoice.

Correspondent Bank: HSBC Bank USA
Swift Code: MRMDUS33
ABA No.021001088

Consignee: HSBC Bank Bermuda Limited
Swift Code: BBDA BMHM
Hamilton, Bermuda

Name of Beneficiary: Petrolifera Petroleum (Colombia) Limited
Account of Beneficiary: No. 011-058781-501
Address of Beneficiary: 300, 625 -11 Avenue SW
Calgary, Alberta, T2R 0E1

14. STANDBY LETTER OF CREDIT

For the purpose of securing payment obligations, BUYER undertakes to obtain an irrevocable Standby Letter of Credit (“SLOC”) issued by a financial institution approved by SELLER for an insured value of USD \$ 4,000,000. Such SLOC shall be valid for one (1) year counted as of the date of entering into this Agreement and shall be duly issued and in force within 10 days following the date of entering into this Agreement.

The SLOC shall remain in force during the term of the Agreement therefore, in the event that the Agreement is extended, the SLOC shall also be extended or a new letter of credit for a term equal to that of the extension(s) shall be issued.

15. NATURE OF THE AGREEMENT

The PARTIES expressly agree and accept that this Agreement does not constitute a labor contract or a labor relationship between SELLER and BUYER's personnel in charge of fulfilling the purpose of this Agreement.

Similarly, the PARTIES expressly establish that this Agreement does not constitute a labor contract or a labor relationship between BUYER and SELLER's personnel in charge of fulfilling the purpose of this Agreement.

According to the above, it shall be understood that the PARTIES are independent companies and are not agents, representatives, employees or intermediaries of the other PARTY with regard to the personnel employed for the execution of this Agreement.

It is expressly understood and stipulated that each and every officer, technician and other personnel appointed by each PARTY to fulfill this Agreement has a specific relationship with that PARTY, thus it is up to each of such PARTIES to make the payments associated with fees, salaries and legal and extra-legal benefits, indemnities, overtime, social benefits, allowances, insurance, etc. and in general shall fulfill all the payments for affiliations and contributions to the Integrated Social Security System and other parafiscal payments (ICBF, SENA, Family Compensation Funds, etc.), set forth in the Colombian legislation.

If, due to a breach of any of the above-mentioned legal and contractual obligations, or due to a breach of Article 34 of the Colombian Substantive Labor Code with its additions and amendments, or if by a court ruling it is determined that the other PARTY shall be jointly and severally liable for the payments and indemnities that correspond to the other PARTY, with regard to one or several employees, the liable PARTY shall reimburse the other PARTY all the amounts it may have paid within three (3) working days following the date of payment.

16. TAXES

Each of the PARTIES shall be liable for the payment of its corresponding taxes in accordance with the Colombian legislation.

17. APPLICABLE LAW

This Agreement shall be governed and construed in accordance with the Laws of the Republic of Colombia.

18. ARBITRATION

The PARTIES agree that in the event of a conflict or dispute in relation to any aspect of this Agreement, they will attempt to resolve their differences by mutual agreement, for which they will have a term of thirty (30) calendar days. If upon expiry of this period the PARTIES have failed to reach an agreement, the matter will be referred to Arbitration, which will be held in the Arbitration and Conciliation Center of Bogotá Chamber of Commerce according to the following rules:

- (i) The Arbitration Tribunal shall be composed of three (3) arbitrators who will be Colombian lawyers, appointed by mutual agreement by the PARTIES, or, if they fail to reach an agreement, by the Bogota Chamber of Commerce.
- (ii) The seat of the Tribunal shall be the city of Bogotá, at the Arbitration and Conciliation Center of Bogotá Chamber of Commerce.
- (iii) The internal organization of the Tribunal will be subject to the rules of the Arbitration and Conciliation Center of Bogotá Chamber of Commerce.
- (iv) The Tribunal shall decide according to law.
- (v) The costs of the Tribunal shall be determined according to the Rules of the Arbitration and Conciliation Center of Bogotá Chamber of Commerce.

19. AMENDMENTS

This Agreement contains all the agreements between the PARTIES regarding the matters which constitute its purpose and it repeals any prior, written or oral agreement, contract and understanding. No amendment, change or extension of this Agreement shall be binding unless it is in writing and is signed by the PARTIES.

20. ASSIGNMENT

Neither of the PARTIES may assign, in whole or in part, this Agreement or the rights, liabilities and obligations of the same without the prior written acceptance of the other PARTY (which acceptance shall not be unreasonably denied).

In the event of assignment, both the assignor and the assignee will be jointly and severally liable for all obligations arising herefrom.

21. NOTICES

The PARTIES establish the following addresses to which any information may be sent or communicated:

PETROLIFERA PETROLEUM (COLOMBIA) LIMITED

Calle 113 No. 7 – 80 Piso 17
Torre AR
Bogotá - Colombia

GUNVOR COLOMBIA SAS (BUYER):

CARRERA 7 #83 -29
OFC 304 CENTRO EMPRESARIAL LA CABRERA
BOGOTÁ - COLOMBIA

Changes of domicile or representatives of the PARTIES shall be notified to the other PARTY in writing within five (5) business days following the date of the change; otherwise, any communication addressed to the last registered address or name of the latest recorded representative shall have identical consequences in law.

22. FORCE MAJEURE, ACT OF GOD, ACTS OF THIRD PARTIES AND ACTS OF THE AUTHORITIES.

The PARTIES shall comply with all the obligations arising from this Agreement, except in cases of *force majeure*, acts of God, acts of third parties or acts of the authorities (hereinafter "Extenuating Circumstances") which shall be duly proven.

Force Majeure and acts of God are understood to be unforeseen events that cannot be resisted and that the PARTIES cannot predict, such as shipwrecks, earthquakes, floods, etc. that prevent either of the PARTIES from meeting their obligations under the Agreement.

Acts of third parties are those acts that prevent compliance in whole or in part with this Agreement and that in addition the PARTIES do not have the legal duty to confront, such as revolts, rebellions, terrorist actions and civil unrest.

Acts of the authorities are activities or decisions stemming from the competent authorities, whether local, regional or national that substantially affects the performance of the obligations arising from this Agreement.

It is understood that Extenuating Circumstances occur under circumstances that are beyond the control of the PARTIES, despite the fact that the PARTIES may have taken the necessary corrective measures that seek to eliminate the causes of the delay or the exclusion.

If as a result of an Extenuating Circumstance, a PARTY is unable to comply in whole or in part with its obligations under this Agreement, the obligations of the PARTY giving such notice, as and to the extent that such obligations may be affected by an Extenuating Circumstance, will be suspended while any inability to meet them persists during the reasonable time that may be required in order that the PARTY can once again meet its obligations, but not for a longer period.

The PARTY that invokes an Extenuating Circumstance shall notify the other PARTY regarding the Extenuating Circumstance as soon as reasonably practicable after the occurrence of the relevant facts and shall keep the other PARTY informed of all aspects. Such notice shall include reasonably full details of the Extenuating Circumstance and the measures that the affected PARTY intends to take to mitigate and remedy the

Extenuating Circumstance and shall also contain an estimate of the time period that the PARTY considers will be required to remedy the Extenuating Circumstance.

The affected PARTY shall use reasonable diligence to mitigate and remove or overcome the Extenuating Circumstance as soon as possible in a commercially reasonable manner but will not be obliged to settle any labor dispute except in terms that are acceptable to therefor. All of these disputes shall be handled with discretion by the affected PARTY.

23. TERMINATION OF THE AGREEMENT

In addition to the other causes of termination described herein, either of the PARTIES may terminate this Agreement, by written notice, as a result of any of the following events:

- a) By unilateral decision of either of the PARTIES to terminate this Agreement before the expiry of its term, giving prior written notice to the other PARTY of ninety (90) working days.

The unilateral termination of this Agreement does not relieve the PARTIES of their undertakings and obligations contracted herein with respect to the confidentiality of the information.

- b) By voluntary or forced dissolution or liquidation of either of the PARTIES;
- c) By the financial insolvency of either of the PARTIES, which shall be presumed once the above-mentioned PARTY incurs in cessation of payments of its obligations or the total or partial attachment of its property.
- d) As a result of the material breach of any of the substantial obligations of the PARTIES under this Agreement.
- e) If either of the PARTIES is subject to receivership.
- f) If either of the PARTIES loses its licenses and the administrative authorizations which give it the right to meet the purpose of this Agreement.
- g) Due to the gross negligence or willful misconduct of the PARTIES in the execution of the Agreement.
- h) Breach by the BUYER (and or conveyor) concerning the HSE policies of the SELLER.

- i) Inability to collect or deliver the volumes of Crude agreed under this Agreement within the terms and times agreed upon between the PARTIES.

If any of the events referred to in this clause occurs, either of the PARTIES may terminate the Agreement within the following thirty (30) calendar days (with the exception of the case referred to in subsection a) of this clause), having the right to exercise the legal actions required to obtain any indemnity in its favor in accordance with Colombian law. For purposes of clarity, it is agreed that any claim or pretension arising from a breach of this Agreement occurring prior to the termination of this Agreement will survive such termination.

Each of the PARTIES undertakes to return to the other, within five (5) days following the notice of termination of the Agreement, if applicable, all documents (in written or electronic form), files and other materials that had been delivered in fulfillment of the purpose of this Agreement.

24. STATEMENT OF LEGITIMACY AND ORIGIN OF THE RESOURCES

By entering into this Agreement, each of the PARTIES declares that it has not engaged in illegal activities or operations, and

- a- That the resources do not originate, directly or indirectly, from an illegal activity provided as such in Colombian law, especially in the Colombian Criminal Code, in supra-legal or international regulations or other regulations that add to them or change them, particularly with respect to activities related to drug trafficking or the laundering of assets.
- b- That neither of the companies that enter into this Agreement, nor its representatives, partners, officials or employees is included by the Office of Foreign Assets Control of the Department of the Treasury of the United States of America in the list of Specially Designated Narcotics Traffickers referred to by the Department of the Treasury ("Clinton List") or any other similar list issued by any Government.
- c- That neither of the companies that are a PARTY to this Agreement, nor its representatives, partners, officers or employees are involved in processes related to illegal activities such as the transport, traffic, processing or negotiation of illegal materials, laundering of assets and / or related activities, terrorism and or similar activities.
- d- That neither of the PARTIES to this Agreement nor its representatives, partners, officers or employees are contributors and / or are linked to armed groups or groups whose conduct is classified as terrorist activities.

25. SEVERABILITY

If at any time one or more provisions of this Agreement is or is established as being illegal, invalid or unenforceable under applicable laws of any jurisdiction, neither the legality, validity or enforceability of the other provisions of the Agreement, nor the legality, validity or enforceability of such provision under the laws of any other jurisdiction shall be affected thereby. Without limiting the foregoing, the PARTIES shall negotiate

in good faith to agree upon the terms of a mutually satisfactory provision to replace the invalid and unenforceable provision.

26. HEALTH AND SAFETY

BUYER shall strictly observe and comply (and shall ensure that the conveyor also complies) with the regulations currently in force regarding industrial safety and occupational health, whether they be of a legal or administrative nature.

Furthermore, BUYER shall observe and follow the instructions (and shall ensure that the conveyor does same) that SELLER issues at any time with respect to the fulfillment of the Agreement and the loading of the Crude.

In consideration of the foregoing, BUYER shall strictly observe (and shall ensure that the conveyor also observes) SELLER's HSE policies (which are attached to this Agreement or which may be submitted in writing to BUYER in the future) and any breach of such policies will lead to the termination of the Agreement. In addition, in the event that SELLER verifies that its HSE policies are not being observed, it may determine not to deliver Crude until BUYER complies with such policies.

27. ANTI-CORRUPTION

Neither BUYER nor its related companies have made, offered or authorized, nor will they make, offers, nor have they authorized any payment, gift, promise or other advantages, related in any way with any of their contracts or operations or matters that are material to this Agreement, whether directly or indirectly through any person or other entity, to or for the use or benefit of any public official (i.e. anyone in legislative, administrative or judicial office, including any person employed by or acting on behalf of a public entity, a public company or a public international organization) or any political party or official of a political party or candidate for office, when such payment, gift or pledge violates:

- (i) The laws / regulations of the country of operations;
- (ii) The laws / regulations of the country of incorporation of the PARTY and the parent company and ultimate beneficiary of such PARTY (or the headquarters of its business);
- (iii) Foreign Corrupt Practices Act (FCPA - U.S.A.); or
- (iv) The principles outlined in the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions, signed in Paris on December 17, 1997, which entered into force on February 15, 1999, and the Commentaries on the Convention.

28. WAIVER

No omission or delay by either of the PARTIES in the exercise of its rights under this Agreement will operate as a waiver thereof, or the single or partial exercise by either of the PARTIES of such right will prevent the further exercise or other exercise thereof or of other rights it may have.

29. CLAIMS

Claims between the PARTIES with respect to the quality and the quantity of the Crude or related to payments under the Agreement shall be delivered to the other PARTY with available support documentation within ninety (90) days following the date of loading of the Crude at the Delivery Point. The PARTY which receives the claim shall not be held liable for any claims received after such date.

30. ENFORCEABILITY

The PARTIES expressly established that this Agreement lends right of enforcement because it is a clear, explicit and enforceable obligation pursuant to the provisions of the Colombian Code of Civil Procedure.

31. LANGUAGE

This Agreement is drafted in Spanish and constitutes the only form of the obligations between the PARTIES. Any translation hereof into another language can only be used for reference purposes between the PARTIES and shall at no time affect the meaning or interpretation of the version in Spanish.

In witness whereof, this Agreement is signed in two (2) counterparts in Bogotá D.C., on the third (3rd) day of the month of December of the year two thousand twelve (2012).

SELLER: Petrolifera Petroleum Colombia Limited. BUYER: GUNVOR COLOMBIA S.A.S.

/s/ Alejandra Escobar Herrera

Alejandra Escobar Herrera

Legal Representative

/s/ Jaime Alejandro Hoyos Juliao

Jaime Alejandro Hoyos Juliao

Legal Representative

/s/ Manuel Antonio Buitrago Vives

Manuel Antonio Buitrago Vives

Legal Representative

SEVENTH AMENDMENT

TO

CREDIT AGREEMENT

dated as of

January 17, 2013

among

SOLANA RESOURCES LIMITED,
as Borrower,

GRAN TIERRA ENERGY INC.,

WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Administrative Agent and Global Coordinator,

and

The Lenders Party Hereto

SEVENTH AMENDMENT TO CREDIT AGREEMENT

THIS SEVENTH AMENDMENT TO CREDIT AGREEMENT
S O L A N A R E (**S** **Borrower**); **U R C E S**
GRAN TIERRA ENERGY INC., a corporation formed and existing under the laws of the State of Nevada (the "Parent"); **WELLS FARGO BANK, NATIONAL ASSOCIATION**, as administrative agent (in such capacity, together with its successors in such capacity, the "Administrative Agent") for the lenders party to the Credit Agreement referred to below (collectively, the "Lenders") and as global coordinator; and the undersigned Lenders.

RECITALS

A. The Borrower, the Parent, the Administrative Agent and the Lenders are parties to that certain Credit Agreement dated as of July 30, 2010, as amended by that certain First Amendment to Credit Agreement dated as of August 31, 2010, that certain Second Amendment to Credit Agreement dated as of November 5, 2010, that certain Third Amendment to Credit Agreement dated as of January 20, 2011, that certain Fourth Amendment to Credit Agreement dated as of February 14, 2011, that certain Fifth Amendment to Credit Agreement dated as of May 18, 2012, and that certain Sixth Amendment to Credit Agreement dated as of October 9, 2012, among the Borrower, the Parent, the Administrative Agent and the Lenders party thereto (the "Credit Agreement"), pursuant to which the Lenders have made certain extensions of credit available to the Borrower.

B. The Borrower has requested and the Lenders have agreed to amend certain provisions of the Credit Agreement.

C. NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

Section 1. Defined Terms. Each capitalized term used herein but not otherwise defined herein has the meaning given such term in the Credit Agreement. Unless otherwise indicated, all references to Sections in this Seventh Amendment refer to Sections of the Credit Agreement.

Section 2. Amendments to Credit Agreement.

2.1 Amendment to Section 9.16. Section 9.16 is hereby amended and restated in its entirety to read as follows:

Section 9.16 Swap Agreements. The Parent will not, and will not permit any Subsidiary to, enter into any Swap Agreements with any Person other than (a) Swap Agreements entered into by the Parent or the Borrower in respect of commodities (i) with an Approved Counterparty and (ii) the notional volumes for which (when aggregated with other commodity Swap Agreements then in effect other than basis differential swaps on volumes already hedged pursuant to other Swap Agreements) do not exceed, as of the date such Swap Agreement is executed, 85% of the reasonably anticipated projected production from proved, developed, producing Oil and Gas Properties of the Parent and the Subsidiaries for each month during the period during which such Swap Agreement is in effect for each of crude oil and natural gas, calculated separately; (b) Swap Agreements entered into by the Parent or the Borrower in respect of interest rates with an Approved Counterparty, as follows: (i) Swap Agreements effectively converting interest rates from fixed to floating, the notional amounts of which (when aggregated with all other Swap Agreements of the Parent and the Borrower then in effect effectively converting interest rates from fixed to floating) do not

exceed 50% of the then outstanding principal amount of the Parent's or Borrower's Debt for borrowed money which bears interest at a fixed rate and (ii) Swap Agreements entered into by the Parent or the Borrower effectively converting interest rates from floating to fixed, the notional amounts of which (when aggregated with all other Swap Agreements of the Parent and the Borrower then in effect effectively converting interest rates from floating to fixed) do not exceed 100% of the then outstanding principal amount of the Parent's Debt for borrowed money which bears interest at a floating rate; and (c) Swap Agreements in respect of foreign exchange and currency option transactions with an Approved Counterparty providing for (1) the purchase by the Borrower or any Guarantor of an agreed amount of Colombian Pesos in exchange for the sale by the Borrower or such Guarantor of an agreed amount of US Dollars (or entitling the Borrower or such Guarantor to purchase at a strike price a specified quantity of Colombian Pesos and to sell at the strike price a specified quantity of US Dollars) and (2) the purchase by the Borrower or any Guarantor of an agreed amount of US Dollars in exchange for the sale by the Borrower or such Guarantor of an agreed amount of Colombian Pesos (or entitling the Borrower or such Guarantor to purchase at a strike price a specified quantity of US Dollars and to sell at the strike price a specified quantity of Colombian Pesos), in each case, to provide protection against fluctuations in currency values for the purpose of making tax payments by or on behalf of itself or any Subsidiary in Colombia. In no event shall any Swap Agreement contain any requirement, agreement or covenant for the Parent or any Subsidiary to post collateral or margin to secure obligations under such Swap Agreement or to cover market exposures and neither the Parent nor the Borrower will enter into any Swap Agreement unless concurrently therewith, the Parent or the Borrower (as applicable) shall have delivered to the Administrative Agent a duly executed consent and agreement of the counterparty to such Swap Agreement in form and substance satisfactory to the Administrative Agent, pursuant to which such counterparty shall (i) consent to the grant of Liens in all of the Parent's or the Borrower's right, title and interest in and to such Swap Agreement to secure the Indebtedness and (ii) agree to make all payments under such Swap Agreement to the Collection Account.

Section 3. Conditions Precedent. This Seventh Amendment shall not become effective until the date on which each of the following conditions is satisfied (or waived in accordance with Section 12.02 of the Credit Agreement) (the "Seventh Amendment Effective Date"):

3.1 The Administrative Agent shall have received from the Lenders, the Borrower, the Parent and the Subsidiary Guarantors, counterparts (in such number as may be requested by the Administrative Agent) of this Seventh Amendment signed on behalf of such Persons.

3.2 No Default shall have occurred and be continuing, after giving effect to the terms of this Seventh Amendment.

Section 4. Miscellaneous.

4.1 Confirmation. The provisions of the Credit Agreement, as amended by this Seventh Amendment, shall remain in full force and effect following the effectiveness of this Seventh Amendment.

4.2 Ratification and Affirmation; Representations and Warranties. The Borrower and the Parent each hereby: (a) acknowledges the terms of this Seventh Amendment; (b) ratifies and affirms its obligations under, and acknowledges, renews and extends its continued liability under, each Loan Document to which it is a party and agrees that each Loan Document to which it is a party remains in full force and effect, except as expressly amended hereby, after giving effect to the amendments contained herein; (c) agrees that from and after the Seventh Amendment Effective Date each reference to the Credit Agreement in the Loan Documents shall be deemed to be a reference to the Credit Agreement, as amended by this Seventh

Amendment; and (d) represents and warrants to the Lenders that as of the date hereof, after giving effect to the terms of this Seventh Amendment: (i) all of the representations and warranties contained in each Loan Document to which it is a party are true and correct in all material respects, unless such representations and warranties are stated to relate to a specific earlier date, in which case, such representations and warranties shall continue to be true and correct in all material respects as of such earlier date and (ii) no Default has occurred and is continuing.

4.3 Loan Document. This Seventh Amendment is a “Loan Document” as defined and described in the Credit Agreement and all of the terms and provisions of the Credit Agreement relating to Loan Documents shall apply hereto.

4.4 Counterparts. This Seventh Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of this Seventh Amendment by facsimile or other electronic transmission shall be effective as delivery of a manually executed counterpart hereof.

4.5 NO ORAL AGREEMENT. THIS SEVENTH AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS EXECUTED IN CONNECTION HEREWITH AND THEREWITH REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR UNWRITTEN ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO ORAL AGREEMENTS BETWEEN THE PARTIES.

4.6 GOVERNING LAW. THIS SEVENTH AMENDMENT (INCLUDING, BUT NOT LIMITED TO, THE VALIDITY AND ENFORCEABILITY HEREOF) SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

[SIGNATURES BEGIN NEXT PAGE]

IN WITNESS WHEREOF, the parties hereto have caused this Seventh Amendment to be duly executed as of the date first written above.

BORROWER: SOLANA RESOURCES LIMITED

By: /s/ Dana Coffield
Name: Dana Coffield
Title: President & CEO

PARENT: GRAN TIERRA ENERGY INC.

By: /s/ Dana Coffield
Name: Dana Coffield
Title: President & CEO

Signature Page
Seventh Amendment to Credit Agreement

ADMINISTRATIVE AGENT: WELLS FARGO BANK, NATIONAL ASSOCIATION,
as Administrative Agent and a Lender

By: /s/ Juan Carlos Sandoval
Name: Juan Carlos Sandoval
Title: Director

By: _____
Name:
Title:

Signature Page
Seventh Amendment to Credit Agreement

RATIFICATION AND AFFIRMATION

Each of the undersigned Guarantors hereby: (a) acknowledges the terms of this Seventh Amendment; (b) ratifies and affirms its obligations under, and acknowledges, renews and extends its continued liability under, each Loan Document to which it is a party and agrees that each Loan Document to which it is a party remains in full force and effect, except as expressly amended hereby, after giving effect to the amendments contained herein; (c) agrees that from and after the Seventh Amendment Effective Date (as defined in this Seventh Amendment) each reference to the Credit Agreement in the Loan Documents shall be deemed to be a reference to the Credit Agreement, as amended by this Seventh Amendment; and (d) represents and warrants to the Lenders that as of the date hereof, after giving effect to the terms of this Seventh Amendment: (i) all of the representations and warranties contained in each Loan Document to which it is a party are true and correct in all material respects, unless such representations and warranties are stated to relate to a specific earlier date, in which case, such representations and warranties shall continue to be true and correct in all material respects as of such earlier date and (ii) no Default has occurred and is continuing.

EXECUTED AS A DEED by:
SOLANA PETROLEUM EXPLORATION
(COLUMBIA) LIMITED

/s/ Cecilia Lopes Victorino
Witness

By: /s/ Julio Moreira
Name: Julio Moreira
Title: Director

GRAN TIERRA EXCHANGE CO INC.

By: /s/ Dana Coffield
Name: Dana Coffield
Title: President & CEO

EXECUTED AS A DEED by:
GRAN TIERRA ENERGY INTERNATIONAL
HOLDINGS LTD.

/s/ Cecilia Lopes Victorino
Witness

By: /s/ Julio Moreira
Name: Julio Moreira
Title: Director

EXECUTED AS A DEED by:
GRAN TIERRA ENERGY CAYMAN
ISLANDS INC.

/s/ Cecilia Lopes Victorino
Witness

By: /s/ Julio Moreira
Name: Julio Moreira
Title: Director

ARGOSY ENERGY, LLC

By: /s/ Julio Moreira
Name: Julio Moreira
Title: Manager

GRAN TIERRA ENERGY COLOMBIA, LTD.
By: Argosy Energy, LLC, the general partner of
Gran Tierra Energy Colombia, Ltd.

By: /s/ Julio Moreira
Name: Julio Moreira
Title: Manager

GRAN TIERRA ENERGY BRASIL LTDA.

By: /s/ Julio Moreira
Name: Julio Moreira
Title: President

WITNESSES:

/s/ Cecilia Lopes Victorino
Name: Cecilia Lopes Victorino
ID:

Name:
ID:

ADDENDUM No. 3 TO TRANSPORTATION CONTRACT NO. VIT – 001 – 2012

Date: Bogotá, D. C., the 30th of December of 2012

Contract No. VIT – 001 – 2012

SENDER: GRAN TIERRA ENERGY COLOMBIA LTD
NIT: 860.516.431-7

TRANSPORTER: ECOPETROL S. A.
NIT: 899.999.068 – 1

TYPE OF CRUDE: OWN PRODUCTION XX OWNERSHIP ___

PURPOSE:

Service of transportation of liquid hydrocarbons through the Mansoya – Orito Pipeline (OMO) and the Trans - Andean Pipeline (OTA).
--

The parties agree to enter into this Addendum, based on the following

R E C I T A L S

1. Contract No. VIT – 001 – 2012 (hereinafter the Contract) is in force between the parties, the purpose of which is the service of transportation of liquid hydrocarbons through the Mansoya – Orito Pipeline (OMO) and the Trans - Andean Pipeline (OTA).
 2. The date of expiration of the contract is the 31st of December of 2012.
 3. The SENDER is interested in expanding the term of execution of the Contract.
 4. ECOPETROL has expressed to the SENDER that, because of the incorporation of the company called CENIT S. A. S. (hereinafter CENIT) it will transfer to that company the transportation assets through which it is currently rendering the services under the Contract. Therefore, as from the date of transfer of the assets, CENIT will provide the service of transportation of liquid hydrocarbons through the Mansoya – Orito Pipeline (OMO) and the Trans - Andean Pipeline (OTA).
-

5. ECOPETROL has expressed its availability to extend the term of execution of the Contract until the 30th of June of 2013, making clear that on the date of delivery of the assets to CENIT, the assignment of the Contract in favor of that company will be effective.

A G R E E M E N T

As from the 1st of January of 2013, the Contract will be amended according to the following clauses:

FIRST: To amend the estimated value of the contract, corresponding to the ECONOMIC CONDITIONS contained in the Specific Conditions of the Contract, as follows:

“Estimated Final Value of the Contract	Nineteen million six hundred and sixty seven thousand dollars of the United States of America (USD \$ 19.667.000).
--	--

SECOND: To amend the insured value that corresponds to the SURETIES contained in the Specific Conditions of the Contract, as follows:

Type of Surety	Total Amount
Performance Bond	Six billion nine hundred and twenty two million pesos Colombian legal tender (\$ 6.922.000)

The SENDER agrees to extend the term of validity of the Surety within five (5) business days after the signature of this Addendum. The respective certificates of amendment must be handed over to ECOPETROL within three (3) calendar days from their date of issue.

The amendment of the guaranty must maintain the cover of the contract for the term thereof plus 120 additional days.

PARAGRAPH: In case of assignment of this contract by ECOPETROL to CENIT the provisions of the nineteenth clause of this Contract will apply.

THIRD: To amend the Third Clause of the General Conditions of the Contract, as follows:

“THIRD CLAUSE

TERM

3.1. The term of execution of the contract will be from the date of signature until the 30th of June of 2013.

3.2. The term of execution of the Service for the Contracted Capacity the purpose of this Contract can be extended by mutual consent of the Parties, by means of a written document entered into before the date of termination thereof, subject to the existence of Available Capacity of the Pipeline during the month of Operation for which the service is intended.

3.3. The monthly payment obligation on the SENDER'S charge regarding the Service, must be done during the entire term of execution of the Contract.

PARAGRAPH: The Parties understand and accept that the extension of the term established in this Addendum only gives the right to the transportation capacity subject to availability in the Pipeline

FOURTH: To amend the Fourteenth Clause of the General Conditions of the Contract, as follows:

"FOURTEENTH CLAUSE CONTRACT TERMINATION

14.1. This Contract will end for the expiration of the term agreed.

14.2. The Parties agree that ECOPETROL may declare the early termination of the Contract at any time, with no settlement of damages whatsoever in favor of the SENDER, in the following events:

- a) The serious breach of the SENDER'S obligations which have not been cured within the grace period, if such is the case;
 - b) The dissolution of the SENDER'S legal entity;
 - c) The unauthorized assignment of the Contract by the SENDER;
 - d) Due to changes in the regulation that makes more onerous the performance of ECOPETROL'S obligations;
-

- e) As a consequence of any of the following causes: (i) the SENDER'S fraud, or (ii) if the SENDER incurs in acts or conducts that endanger the operational and / or technical stability of the Pipelines;
- f) By written notice in which ECOPETROL informs the early termination of the Contract. Said written notice must be sent to the SENDER no less than thirty (30) calendar days before the effective date of termination of the Contract.
- g) In case that the SENDER does not file or does not renew the Surety in the terms established in this Agreement.

14.3. The termination will not release the Parties from their corresponding obligations and responsibilities attributable to terms prior to the end date.

14.4. The early termination of this contract will not release the SENDER from the obligations that survive the termination of the Contract, in particular the one related to the payment of the Fees pending and the payment of the penalty, as well as the confidentiality.

14.5. For the purposes of the application of this clause, no prior judicial or private requirement whatsoever will be required”.

FIFTH: To amend the Nineteenth Clause of the General Conditions as follows:

“NINETEENTH CLAUSE
ASSIGNMENT

19.1. The SENDER cannot assign or transfer its rights or obligations under this Contract, and it cannot be substituted in its contractual position, without the prior written authorization of ECOPETROL. For the study and approval of the assignment, the SENDER must evidence that it is on time for all concepts regarding its contractual obligations. The company that replaces the SENDER must have enough financial, technical, administrative and legal capacity to comply with the obligations of this Contract.

19.2. The authorized successors and assignees must assume all of the SENDER'S responsibilities and obligations hereunder, as well as the provisions of the Clause regarding the Sureties of the General and Specific Conditions, and such demands must be expressly stipulated in the instrument that evidences such assignment.

19.3. ECOPETROL will not require any authorization of the SENDER to assign this Contract.

19.4. Without prejudice to the foregoing, the SENDER hereby authorizes, from now, the assignment of this contract to CENIT. In case that this assignment takes place, ECOPETROL will give written notice of the assignment to the SENDER. The Parties understand and accept that the assignment to CENIT does not require the authorization or acceptance of any additional one on the SENDER'S part

19.5. Once the assignment is effective, the SENDER understands and accepts that it and CENIT will revise the commercial conditions of this contract.

FIRST PARAGRAPH: In a maximum term of ten (10) business days as from the notification of the assignment of this contract to CENIT, the SENDER must amend the surety purchased in favor of ECOPETROL to add CENIT as beneficiary thereof.

SECOND PARAGRAPH: As from the date of assignment of this contract to CENIT by ECOPETROL, the SENDER understands and accepts that Annex No. 1 to the Contract by the Transporter Manual, Offloading Standards and all other norms established by CENIT and in consequence, it will be applied according to the provisions established for these purposes in the Contract”.

SIXTH: To amend the Twenty Sixth Clause of the General Conditions, as follows:

TWENTY SIXTH CLAUSE
INTEGRALITY

26.1. This Contract is the only and integral agreement regarding the purpose thereof, and replaces any prior agreement that has not been established in the Contract.

26.2. The following documents are integral part of the Contract:

ANNEX 1 : ECOPETROL S. A.: PIPELINE'S TRANSPORTER MANUAL
ANNEX 2 : GUIDE FOR THE MANAGEMENT OF ACCOUNTS PAYABLE AND SERVICES
ANNEX 3 : ECOPETROL'S GENERAL CLAUSES FOR THE PERFORMANCE BOND
ANNEX 4: : MODEL OF THE STAND BY LETTER OF CREDIT.

26.3. Likewise, are integral part of this Contract all the rules and procedures that ECOPETROL or its assignees have established for the performance of the activities the subject matter of this Contract.

26.4. If any provision of this contract is forbidden, void, inefficacious or cannot be enforceable according to the applicable provisions, all other provisions will survive it with full binding and mandatory effects for the Parties, unless if the provision that is forbidden, void, inefficacious or unenforceable is an essential one, in a way that the construal or performance thereof in the absence of such provision is not possible”.

SEVENTH: With the exception of the foregoing provisions, all the clauses of the Contract will be applicable to the contractual relations between ECOPETROL and the SENDER. This Addendum is not a novation of Contract No. VIT – 001 – 2012, which remains in full force in all of its parts that were not expressly amended by this document

EIGHTH: This Addendum is perfected with the execution thereof. For its execution, the approval of the surety on the charge of the SENDER is required.

In witness hereof, it is signed in two identical counterparts in the city of Bogotá, D. C, on the thirtieth (30th) day of the month of December of year 2012.

BY THE SENDER:

BY ECOPETROL:

Signed; <u>/s/ Alejandra Escobar Herrera</u>	Signed; <u>/s/ Martha Escheverri Benjumea</u>
Name: ALEJANDRA ESCOBAR HERRERA	Name: MARTHA ECHEVERRI BENJUMEA
Position: Legal Representative C. C . No. 52.646.943 of Bogotá, D. C.	Position: Acting Head of the Transportation Services' Commercial Department
Signature: <u>/s/ Ivan Tobon Garcia</u>	
Name: IVÁN TOBÓN GARCÍA	
Position: Legal Representative C. C . No. 79.751.294 of Bogotá, D. C.	

ADDENDUM No. 3 TO TRANSPORTATION CONTRACT NO. VIT – 005 – 2012

Date: Bogotá, D. C., the 30th of December of 2012

Contract No. VIT – 005 – 2012

SENDER: PETROLIFERA PETROLEUM (COLOMBIA) LIMITED
NIT: 900.139.306 – 1

TRANSPORTER: ECOPETROL S. A.
NIT: 899.999.068 – 1

TYPE OF CRUDE: OWN PRODUCTION XX OWNERSHIP ___

PURPOSE:

Service of transportation of liquid hydrocarbons through the Mansoya – Orito Pipeline (OMO) and the Trans - Andean Pipeline (OTA).

The parties agree to enter into this Addendum, based on the following

R E C I T A L S

1. Contract No. VIT – 005 – 2012 (hereinafter the Contract) is in force between the parties, the purpose of which is the service of transportation of liquid hydrocarbons through the Mansoya – Orito Pipeline (OMO) and the Trans - Andean Pipeline (OTA).
 2. The date of expiration of the contract is the 31st of December of 2012.
 3. The SENDER is interested in expanding the term of execution of the Contract.
 4. ECOPETROL has expressed to the SENDER that, because of the incorporation of the company called CENIT S. A. S. (hereinafter CENIT) it will transfer to that company the transportation assets through which it is currently rendering the services under the Contract. Therefore, as from the date of transfer of the assets, CENIT will provide the service of transportation of liquid hydrocarbons through the Mansoya – Orito Pipeline (OMO) and the Trans - Andean Pipeline (OTA).
-

5. ECOPETROL has expressed its availability to extend the term of execution of the Contract until the 30th of June of 2013, making clear that on the date of delivery of the assets to CENIT, the assignment of the Contract in favor of that company will be effective.

A G R E E M E N T

As from the 1st of January of 2013, the Contract will be amended according to the following clauses:

FIRST: To amend the estimated value of the contract, corresponding to the ECONOMIC CONDITIONS contained in the Specific Conditions of the Contract, as follows:

Estimated Final Value of the Contract	Nineteen million six hundred and sixty seven thousand dollars of the United States of America (USD \$ 19.667.000).
---------------------------------------	--

SECOND: To amend the insured value that corresponds to the SURETIES contained in the Specific Conditions of the Contract, as follows:

Type of Surety	Total Amount
Performance Bond	Six billion nine hundred and twenty two million pesos Colombian legal tender (\$ 6.922.000)

The SENDER agrees to extend the term of validity of the Surety within five (5) business days after the signature of this Addendum. The respective certificates of amendment must be handed over to ECOPETROL within three (3) calendar days from their date of issue.

The amendment of the guaranty must maintain the cover of the contract for the term thereof plus 120 additional days.

PARAGRAPH: In case of assignment of this contract by ECOPETROL to CENIT the provisions of the nineteenth clause of this Contract will apply.

THIRD: To amend the Third Clause of the General Conditions of the Contract, as follows:

"THIRD CLAUSE
TERM

3.1. The term of execution of the contract will be from the date of signature until the 30th of June of 2013.

3.2. The term of execution of the Service for the Contracted Capacity the purpose of this Contract can be extended by mutual consent of the Parties, by means of a written document entered into before the date of termination thereof, subject to the existence of Available Capacity of the Pipeline during the month of Operation for which the service is intended.

3.3. The monthly payment obligation on the SENDER'S charge regarding the Service, must be done during the entire term of execution of the Contract.

PARAGRAPH: The Parties understand and accept that the extension of the term established in this Addendum only gives the right to the transportation capacity subject to availability in the Pipeline

FOURTH: To amend the Fourteenth Clause of the General Conditions of the Contract, as follows:

"FOURTEENTH CLAUSE
CONTRACT TERMINATION

14.1. This Contract will end for the expiration of the term agreed.

14.2. The Parties agree that ECOPETROL may declare the early termination of the Contract at any time, with no settlement of damages whatsoever in favor of the SENDER, in the following events:

- a) The serious breach of the SENDER'S obligations which have not been cured within the grace period, if such is the case;
 - b) The dissolution of the SENDER'S legal entity;
 - c) The unauthorized assignment of the Contract by the SENDER;
 - d) Due to changes in the regulation that makes more onerous the performance of ECOPETROL'S obligations;
 - e) As a consequence of any of the following causes: (i) the SENDER'S fraud, or (ii) if the SENDER incurs in acts or conducts that endanger the operational and / or technical stability of the Pipelines;
-

- f) By written notice in which ECOPETROL informs the early termination of the Contract. Said written notice must be sent to the SENDER no less than thirty (30) calendar days before the effective date of termination of the Contract.
- g) In case that the SENDER does not file or does not renew the Surety in the terms established in this Agreement.

14.3. The termination will not release the Parties from their corresponding obligations and responsibilities attributable to terms prior to the end date.

14.4. The early termination of this contract will not release the SENDER from the obligations that survive the termination of the Contract, in particular the one related to the payment of the Fees pending and the payment of the penalty, as well as the confidentiality.

14.5. For the purposes of the application of this clause, no prior judicial or private requirement whatsoever will be required”.

FIFTH: To amend the Nineteenth Clause of the General Conditions as follows:

“NINETEENTH CLAUSE
ASSIGNMENT

19.1. The SENDER cannot assign or transfer its rights or obligations under this Contract, and it cannot be substituted in its contractual position, without the prior written authorization of ECOPETROL. For the study and approval of the assignment, the SENDER must evidence that it is on time for all concepts regarding its contractual obligations. The company that replaces the SENDER must have enough financial, technical, administrative and legal capacity to comply with the obligations of this Contract.

19.2. The authorized successors and assignees must assume all of the SENDER’S responsibilities and obligations hereunder, as well as the provisions of the Clause regarding the Sureties of the General and Specific Conditions, and such demands must be expressly stipulated in the instrument that evidences such assignment.

19.3. ECOPETROL will not require any authorization of the SENDER to assign this Contract.

19.4. Without prejudice to the foregoing, the SENDER hereby authorizes, from now, the assignment of this contract to CENIT. In case that this assignment takes place, ECOPETROL will give written notice of the assignment to the SENDER. The Parties understand and accept that the assignment to CENIT does not require the authorization or acceptance of any additional one on the SENDER’S part

19.5. Once the assignment is effective, the SENDER understands and accepts that it and CENIT will revise the commercial conditions of this contract.

FIRST PARAGRAPH: In a maximum term of ten (10) business days as from the notification of the assignment of this contract to CENIT, the SENDER must amend the surety purchased in favor of ECOPETROL to add CENIT as beneficiary thereof.

SECOND PARAGRAPH: As from the date of assignment of this contract to CENIT by ECOPETROL, the SENDER understands and accepts that Annex No. 1 to the Contract by the Transporter Manual, Offloading Standards and all other norms established by CENIT and in consequence, it will be applied according to the provisions established for these purposes in the Contract”.

SIXTH: To amend the Twenty Sixth Clause of the General Conditions, as follows:

TWENTY SIXTH CLAUSE
INTEGRALITY

26.1. This Contract is the only and integral agreement regarding the purpose thereof, and replaces any prior agreement that has not been established in the Contract.

26.2. The following documents are integral part of the Contract:

ANNEX 1 : ECOPETROL S. A.: PIPELINE’S TRANSPORTER MANUAL
ANNEX 2 : GUIDE FOR THE MANAGEMENT OF ACCOUNTS PAYABLE AND SERVICES
ANNEX 3 : ECOPETROL’S GENERAL CLAUSES FOR THE PERFORMANCE BOND
ANNEX 4: : MODEL OF THE STAND BY LETTER OF CREDIT.

26.3. Likewise, are integral part of this Contract all the rules and procedures that ECOPETROL or its assignees have established for the performance of the activities the subject matter of this Contract.

26.4. If any provision of this contract is forbidden, void, inefficacious or cannot be enforceable according to the applicable provisions, all other provisions will survive it with full binding and mandatory effects for the Parties, unless if the provision that is forbidden, void, inefficacious or unenforceable is an essential one, in a way that the construal or performance thereof in the absence of such provision is not possible”.

SEVENTH: With the exception of the foregoing provisions, all the clauses of the Contract will be applicable to the contractual relations between ECOPETROL and the SENDER. This Addendum is not a novation of Contract No. VIT – 005 – 2012, which remains in full force in all of its parts that were not expressly amended by this document

EIGHTH: This Addendum is perfected with the execution thereof. For its execution, the approval of the surety on the charge of the SENDER is required.

In witness hereof, it is signed in two identical counterparts in the city of Bogotá, D. C, on the thirtieth (30th) day of the month of December of year 2012.

BY THE SENDER:

BY ECOPETROL:

Signed; <u>/s/ Alejandra Escobar Herrera</u>	Signed; <u>/s/ Martha Escheverri Benjumea</u>
Name: ALEJANDRA ESCOBAR HERRERA	Name: MARTHA ECHEVERRI BENJUMEA
Position: Legal Representative C. C . No. 52.646.943 of Bogotá, D. C.	Position: Acting Head of the Transportation Services' Commercial Department
Signature: <u>/s/ Ivan Tobon Garcia</u>	
Name: IVÁN TOBÓN GARCÍA	
Position: Legal Representative C. C . No. 79.751.294 of Bogotá, D. C.	



Date: February 15, 2013
To: Solana Resources Ltd
From: Wells Fargo Bank NA
Subject: February 2013 Interim Borrowing Base Redetermination – Effectiveness Memo

Pursuant to Section 2.07 of the Credit Agreement dated July 30, 2010 for Solana Resources Ltd (“Solana”), the Administrative Agent hereby provides notice that the Borrowing Base amount for Solana has been increased to \$100,000,000 and is now effective (as of February 15, 2013) until the next scheduled borrowing base redetermination.

Final allocations are as follows:

Lender	Total Allocation	
	\$	%
Wells Fargo Bank	\$100,000,000.00	100.00%
Total	\$100,000,000.00	100.00%

Exhibit 10.76

ARGOSYENERGYINTERNATIONAL

“ C H A Z A “

CONTRACT FOR THE EXPLORATION AND EXPLOITATION OF HYDROCARBONS

Effective Date:

The 27th of June of 2005

Certified Translation of a document originally in Spanish 13 February 2013
No. 938 - 13 THIS SIDE VALID ONLY Page 2 of 2

The undersigned translator assumes no responsibility whatsoever for the contents or authenticity of the document(s) submitted for translation

NATIONAL HYDROCARBONS' AGENCY

CONTRACT FOR THE EXPLORATION AND EXPLOITATION OF HYDROCARBONS

SECTOR: CHAZA

CONTRACTOR: ARGOSY ENERGY INTERNATIONAL

EFFECTIVE DATE: The 27th of June of 2005

The undersigned, to wit: on the one hand, the National Hydrocarbons' Agency, hereinafter **ANH**, a Special Administrative Unit attached to the Ministry of Mines and Energy, created by Decree – Law 1760 of 26 June 2003, with its main seat of business at Bogotá, D. C., represented herein by JOSE ARMANDO ZAMORA REYES, of legal age, bearer of I. D. Number 19.303.017 of Bogotá, domiciled in Bogotá, D. C., who represents that: 1. In his capacity as General Director of the ANH appears in the name and in behalf of said Agency; and 2. For the execution of this agreement it has been authorized by the ANH'S Council of Directors according to Minutes Number 33 dated on the twenty first (21st) day of April of two thousand and five (2005), and on the other hand **ARGOSY ENERGY INTERNATIONAL**, a company incorporated according to the laws of the United States of America with its main place of Business in Salt Lake City, Utah, with a Branch Office established in Colombia and the main place of business in Bogotá, D. C., according to Public Deed Number 5323 dated on the 25th of October of 1983 of Notary 7 of Bogotá, D. C., represented herein by VICTOR HUGO FRANCO TAMAYO, of legal age, Colombian citizen, with I. D. Number 19.474.671 of Bogotá, who represents: 1. That in his capacity as First Alternate to the Legal Representative represents the company called ARGOSY ENERGY INTERNATIONAL; 2. That he is duly authorized to enter into this contract according to the Certificate of Existence and Incumbency issued by the Chamber of Commerce of Bogotá, D. C. 3. That represents, under oath, that neither he nor the company represented by him have fallen in a cause for disqualification or incompatibility to enter into this contract; and 4. That ARGOSY ENERGY INTERNATIONAL has evidenced that it has, and undertakes to maintain, the financial capacity, the technical competence and the professional skills required to perform the activities hereunder.

The aforementioned company shall be called, hereinafter and for all purposes, THE CONTRACTOR.

The ANH and the CONTRACTOR hereby evidence that they have executed the contract contained in the following clauses:

CLAUSE 1 – DEFINITIONS

For the purposes of this contract, the following expressions shall have the meaning herein assigned.

Exhibits A, B and C are integral part hereof, and, therefore, every time the expressions subject of this clause appear in them, they will have the same meanings given herein.

- 1.1. Abandonment:** It is the plugging and abandonment of wells, the dismantling of facilities and the cleanup and environmental restoration of the areas in which Exploration, Evaluation or Exploitation operations have been made hereunder, according to the laws of Colombia.
- 1.2. Year:** It refers to the term of twelve (12) consecutive months according to the Gregorian Calendar, counted as of a specific date.
- 1.3. Calendar Year:** It is the twelve – month (12) term comprised between the first (1st) day of January and the thirty first (31st) day of December, both included, of every year.
- 1.4. Contracted Area:** It is the surface and its projection in the subsoil identified in Clause 3 and with the boundaries set forth in Exhibit A, in which the CONTRACTOR is authorized, by virtue of this contract, to perform the operations of Exploration, Evaluation and Exploitation of hydrocarbons hereunder.
- 1.5. Evaluation Area:** It is the portion of the Contracted Area in which the CONTRACTOR has made a discovery and in which it has decided to do carry an Evaluation Program out in order to determine whether or not it is commercial, pursuant to Clause 7. The area shall be comprised by a regular surface polygon, preferably of four sides, that shall comprise the sheathing of the vertical surface projection of the geological trap or structure that contains the discovery.
- 1.6. Exploitation Area:** It is the portion of the contracted area in which one or more commercial fields are allocated, as per the provisions of Clause 9 (Section 9.3) hereof. The area of each commercial field shall comprise the sheathing of the vertical surface of the deposit or deposits that make it up and that are defined by the Ministry of Mines and Energy as per Decree 3229 of 11 November 2003, as amended or replaced.
- 1.7. Barrel:** It is the unit for the measurement of Liquid Hydrocarbons consisting of forty two (42) gallons of the United States of America, corrected to standard conditions (a temperature of sixty degrees Fahrenheit (60 °F) and absolute pressure of one (1) atmosphere).
- 1.8. Oil Industry's Good Practices:** It refers to the good, safe and efficient procedures usually employed by prudent and diligent operators in the international oil industry, under conditions and circumstances similar to those that arise pursuant to the activities hereunder, mainly in issues related to the use of adequate methods and processes to obtain the maximum financial benefit in the final recovery of the reserves, the reduction of losses, the operational safety and the environmental protection, among other, as long as they are not against the Laws of Colombia.
- 1.9. Commercial Field:** It is the portion of the Contracted Area in the subsoil of which there is one or more deposits discovered which the CONTRACTOR has decided to exploit in a commercial manner.
- 1.10. Declaration of Commerciality:** It is the written communication sent by the CONTRACTOR to the ANH in which it declares that the discovery made in the Contracted Area is a Commercial Field.

- 1.11. Discovery:** It is construed that there is a hydrocarbons' deposit discovered whenever by means of drilling with a rig or with similar equipment and the relevant fluids' tests the finding of the rock in which the hydrocarbons are accumulated is found, and which behaves as an independent unit in terms of mechanisms of production, petro-physical properties and fluid properties.
- 1.12. Discovery of Non – Associated Natural Gas:** It is the discovery whose official evidence of discovery, in the understanding that the evidence is representative of the deposit or deposits discovered, indicates a Gas / Oil Ratio (GOR) in excess of 7.000 standard cubic feet of gas per barrel of liquid hydrocarbons as well as a molar heptanes (C₇₊) composition lower than 4.0%. It is construed as GOR the ratio between the Natural Gas Volume in cubic feet per day and the volume of liquid hydrocarbons in barrels per day produced by a well, and the molar heptanes (C₇₊) composition as the molar percentage of heptanes and other hydrocarbons of a higher molecular weight. The Gas / Oil Ratio (GOR) of a Discovery with several deposits shall be established with the weighed average of production of each deposit and the molar heptanes (C₇₊) composition as the plain arithmetic average.
- 1.13. Day:** Twenty four – hour (24) term that starts at Zero Hours (00:00) and ends at Twenty Four Hours (24:00).
- 1.14. Development or Development Operations:** Refers to the activities and works performed by the CONTRACTOR including, but not limited to: the drilling, completion and equipping of development wells; the design, construction, installation of equipment, pipes, transfer lines, storage tanks, artificial production methods, primary and improved recovery systems, transshipment systems, storage, among other, within an Exploitation Area in the Contracted Area and outside it whenever necessary.
- 1.15. Exploration or Operation Operations:** It refers to all the studies, jobs and works done by the CONTRACTOR to establish the existence and location of hydrocarbons in the subsoil that include, but are not limited to, geophysical, geochemical, geological, cartographic methods and, in general, the activities of surface prospection, the drilling of exploratory wells and other operations directly related to the search for hydrocarbons in the subsoil.
- 1.16. Assessment or Assessment Operations:** It refers to all the operations and activities performed by the CONTRACTOR in an Assessment Area as per Clause 7 hereof, in order to evaluate a Discovery, to delimit the geometry of the deposit or deposits within the Assessment Area and to establish, among other things, the feasibility of extracting such Hydrocarbons in economically exploitable quantity and quality and the impact it has on the environment and the social environment that its commercial exploitation can cause. Such operations include the drilling of Exploratory Wells, the acquisition of seismic detail programs, the performance of production tests, and, in general, other operations aimed to establishing whether or not the Discovery is a Commercial Field and to delimit it.
- 1.17. Exploitation:** Comprises the development and production.
- 1.18. Effective Date:** It is the day in which this contract is signed and as of which all the terms hereof shall be counted.

- 1.19. Natural Gas:** It is the mix of hydrocarbons in a gaseous state in standard conditions (a temperature of sixty degrees Fahrenheit (60 °F) and absolute pressure of one (1) atmosphere) made up by the most volatile members of the paraffinic series of Hydrocarbons.
- 1.20. Hydrocarbons:** Are all the organic compounds mainly made up by the natural mixture of carbon and hydrogen, as well as those substances that accompany them or that are derived thereof.
- 1.21. Liquid Hydrocarbons:** Are all those hydrocarbons produced in the Contracted Area that, in standard temperature and pressure conditions (a temperature of sixty degrees Fahrenheit (60 °F) and absolute pressure of one (1) atmosphere) are in a liquid state in the head of the well or in the separator, as well as the distilled and condensed extracted from gas.
- 1.22. Heavy Liquid Hydrocarbons:** Are all those Liquid Hydrocarbons with API gravity equal to or lower than fifteen degrees (15 °API).
- 1.23. Late Payment Interest:** Regarding pesos, it shall be the maximum interest rate legally allowed, certified by the competent authority; regarding dollars of the United States of America, it shall be the Principal three – month (3) LIBOR (London Interbank Borrowing Offered Rate) Rate for deposits in dollars, plus four percentage points (LIBOR plus 4%).
- 1.24. Month:** Term counted as of any day of a Calendar Month and that ends on the day before the same day of the next calendar month or, if it is the first day of the month, ending on the last day of the same month.
- 1.25. Parties:** At the time of execution hereof, the ANH and the CONTRACTOR. Afterwards, and, at any time, the ANH, on the one hand, and the CONTRACTOR and / or its assignees duly accepted by the ANH, on the other.
- When the CONTRACTOR party is made up by a plural number of companies, they will nominate one single company to act as its representative before the ANH.
- 1.26. Exploration Period:** It is the six – year (6) term as of the effective date, as well as any extension granted, through which the contractor must perform the Minimum Exploratory Program.
- 1.27. Exploitation Period:** Is, regarding each Exploitation Area, the term of up to twenty four (24) years and its extension, if any, as of the date of Declaration of Commerciality of the Commercial Field through which the CONTRACTOR must carry out the Development and Production operations.
- 1.28. Exploitation Plan:** It is the guideline document prepared by the CONTRACTOR pursuant to clauses 9 and 10 hereof to carry out the technical, efficient and economic exploitation of each Exploitation Area and it shall contain, among other things, the calculation of the reserves of Hydrocarbons, the description of facilities for the Production and transportation of Hydrocarbons, the short and middle hydrocarbons' production forecasts, an abandonment program and the Exploitation Works Programs for the remainder of the current Calendar Year or of the next Calendar Year.

- 1.29. Exploratory Well:** It is a well to be drilled by the CONTRACTOR in the Contracted Area in search of deposits of Hydrocarbons in an area not yet tested as hydrocarbons' producer, or to find a discovery's additional deposits or to extend the boundaries of the known deposits in a Discovery.
- 1.30. Production or Production Operations:** Are all operations and activities performed by the CONTRACTOR in an Exploitation Area regarding the processes of extraction, collection, treatment, storage and transshipment of the Hydrocarbons up to the Point of Delivery, the Abandonment and all other operations pertaining to obtaining hydrocarbons.
- 1.31. Minimum Exploratory Program:** It is the Exploration Operations Program agreed upon in Clause 5 (Section 5.1) hereof that the CONTRACTOR undertakes to execute, as a minimum, during each phase of the Exploration Period in which he is.
- 1.32. Subsequent Exploratory Program:** It is the Exploration Operations Program that the CONTRACTOR undertakes to execute after the end of the Exploration Program, according to the provisions of Clause 6 (Section 6.1).
- 1.33. Assessment Program:** It is the Assessment Operations Program submitted by the CONTRACTOR to the ANH as per Clause 7 hereof, in order to evaluate a Discovery and to establish whether or not it is a Commercial Field. The execution of the Assessment Program and the submission of a Results' Report to the ANH are requirements to declare a Discovery as Commercial Field.
- 1.34. Work Program:** It is the description of the Contracted Area's Exploration, Assessment and / or Exploitation activities and operations as per the terms of this agreement. The Work Program shall include the schedule according to which the CONTRACTOR shall start and complete the relevant activities and budget.
- 1.35. Point of Delivery:** It is the location agreed upon by the parties in which the production of hydrocarbons of each field is measured, in the minimum specifications of entry to any transportation system used by the CONTRACTOR in order to establish the volume of Hydrocarbons pertaining to the royalties and the CONTRACTOR'S volume of hydrocarbons.

CLAUSE 2 - PURPOSE

- 1. Purpose:** By virtue of this Contract, the right to explore the contracted Area and to exploit the Hydrocarbons owned by the State discovered within said area is granted to the CONTRACTOR on exclusive basis. The CONTRACTOR shall be entitled to the part of the production of Hydrocarbons from the contracted Area as correspond as per Clause 14 hereof.
- 2.1. Scope:** The CONTRACTOR , pursuant to that right, shall carry out all the activities and operations subject matter of this Agreement, at its sole cost and risk, providing all resources required to project, prepare and perform the Exploration, Assessment, Development and Production activities within the Contracted Area.

- 2.2. Exclusion of Rights on Other Natural Resources:** The rights granted hereunder exclusively refer to the Hydrocarbons owned by the State discovered within the Contracted Area and, therefore, shall not extend to any other natural resource that might exist in that area.

CLAUSE 3 – CONTRACTED AREA

- 2. Size:** The contracted area comprises a total extension of approximately thirty two thousand four hundred and seventy two (32.472) hectares and six thousand eight hundred and ninety three (6.893) square meters. It is the area described in Exhibit “A” that is part of this contract and is located between the municipal jurisdictions of Mocoa and Villagarzón in the Department of Putumayo, and Piamonte, in the Department of Cauca. The contracted area shall be gradually reduced as per the provisions of this Clause.

- 3.1. Restrictions:** In the event that a portion of the Contracted Area includes areas comprised within the Natural National Parks’ System or other reserved, excluded or restricted areas, geographically delimited by the competent authorities, or when some zones of the aforementioned characteristics overlap with the contracted area, the CONTRACTOR commits to abide by the conditions that, regarding those conditions, are imposed by the competent authorities. The ANH shall assume no responsibility whatsoever in this respect.

Any time that a claim regarding the private property of the hydrocarbons in the subsoil of the Contracted Area is brought to the attention of the ANH it shall undergo the pertinent proceedings as per the legal provisions in force.

- 3.2. Handing back the CONTRACTOR’S exploration, Assessment and Exploitation Areas:** The CONTRACTOR shall hand back the Exploration, Evaluation and Exploitation areas in all the events established hereof as causes of devolution, either by resignation, expiration of terms, the events set forth in Clause 8 (Section 8.2) or for not performing the activities of the relevant Work Programs or, in general, for any other contractual reason that imposes on the CONTRACTOR the obligation to hand the relevant area back.

- 3.3. Voluntary Returns:** The CONTRACTOR can make, at any time, partial returns of the Contracted Area provided it does not affect the performance of the obligations contracted hereunder. If such voluntary devolutions are made during the term of the Exploration Period, they shall be accounted as obligatory devolution of Areas.

- 3.4. Restoration of the Returned Areas:** The CONTRACTOR shall perform all Abandonment activities required and it will restore the returned areas as per the provisions in the Laws of Colombia and in this Contract.

- 3.5. Outlining of the returned areas:** The areas returned by the CONTRACTOR shall comprise the lower possible number of adjacent rectangular blocks limited by lines in north – south and east – west directions, following a grid similar to the one formed by the cartographic plates of the “Agustin Codazzi” Geographical Institute.

- 3.6. Formalization of the Devolution of Areas:** Any devolution of Areas made pursuant to this contract shall be formalized in Document entered into by the parties.

CLAUSE 4 – TERM AND PERIODS

- 3. Term:** The term of this agreement shall be established according to the following clauses.
- 4.1. Exploration Period:** The Exploration Period shall last six (6) years as of the Effective Date and is divided in the phases described below. The first phase of the Exploration Period starts on the Effective Date and the subsequent phases start on the calendar day immediately after the end of the preceding phase.
- Phase 1, with a twelve – month (12) term;
- Phase 2, with a fifteen – month (15) term;
- Phase 3, with a fifteen – month (15) term;
- Phase 4, with a twelve – month (12) term;
- Phase 5, with a twelve – month (12) term;
- Phase 6, with a six – month (6) term;
- 4.1.1. Right to resign During the Exploration Period:** Throughout the course of any of the phases of the Exploration Period, the CONTRACTOR shall be entitled to quit this Contract, provided it has satisfactorily complied with the Minimum Exploratory Program of the current phase as well as all other obligations in its charge for such purposes. The CONTRACTOR shall give written notice to the ANH before the termination of the current phase.
- 4.1.2. Extension of one Phase of the Exploration Period:** Upon the CONTRACTOR'S request, the ANH shall extend the current phase of the Exploration Period, until the completion of the drilling of the Exploratory Wells and / or the acquisition of the seismic program and two (2) more Months, provided that the following conditions are met:
- a) That the aforementioned Exploration Operations are part of the Minimum Exploratory Program and that they were started at least one (1) month before the date of termination of the respective phase of the Exploration Period.
 - b) That the CONTRACTOR had uninterruptedly performed such exploratory operations, and
 - c) That notwithstanding the diligence applied for the execution of such Exploratory Operations, the CONTRACTOR reasonably estimates that the remaining time is not enough to conclude them before the expiration of the current phase.

With the application for extension, the CONTRACTOR shall furnish the ANH with the documents in which it bases its application and the relevant guaranty as per the requirement in Clause 22 hereof.

4.1.3. Termination of the contract because of Expiration of the Exploratory Period: The contract shall end upon the expiration of the Exploration period, if there is not an Assessment Area, Exploration Area or a Discovery made in the Contracted Area by the Contractor in the last phase of the Exploration Period. In this case, the CONTRACTOR shall hand back to the ANH the entire Contracted Area, on top of the performance of all other obligations, and it is obligated to demonstrate that it has complied with the Abandonment Obligations, and being obligated to demonstrate that it has complied in it with all the Abandonment obligations. Evidencing that the wells drilled have been duly plugged and abandoned, that the surface facilities have been completely dismantled and that it has performed all cleanup and environmental restoration activities in conformity to the applicable rules.

4.2. Exploitation Period:

The Exploitation Period is independent for each Exploitation Area and therefore all mentions to the term, extension or duration thereof are referred to each particular Exploitation Area.

4.2.1. Term: The Exploitation Term shall have a term of twenty four (24) years as of the date in which the ANH receives from the CONTRACTOR the Declaration of Commerciality subject of the Eighth Clause hereof.

4.2.2. Extension of the Exploitation Period: The ANH shall extend the Exploitation Period until the economic limit of the Commercial Field, at the CONTRACTOR'S election, provided the following conditions are met:

- a) That the contractor applies with the ANH for the extension in writing, no more than four (4) years and no less that one (1) year before the date of expiration of the Exploitation period of the respective Exploitation Area.
- b) That on the date of application the Exploitation Area is regularly producing hydrocarbons.
- c) That the CONTRACTOR evidences that throughout the four (4) Calendar Years prior to the date of application it has performed an exploration program including at least one well per Calendar Year and / or that it has had one project for the maintenance of pressure or of secondary, tertiary or improved recovery in force.

Paragraph: If the CONTRACTOR does not satisfy in a complete manner or in its entire scope the condition in subparagraph c) above, the ANH, having analyzed the justifications presented by the CONTRACTOR, can grant the extension. It is hereby understood that the ANH'S denial thereof shall not be construed as disagreement and it shall not be subject to the procedure set forth in Clause 27 hereof. In all cases, the extension of the Exploitation Period shall be formalized in an Addendum to the Contract.

- 4.2.3. Voluntary Termination of the Exploitation Period:** At any time throughout the Exploitation Period the CONTRACTOR can end this contract respecting any Exploitation Area, for which it will inform it to the ANH, in writing, at least three (3) months in advance, notwithstanding the performance of all other obligations.
- 4.2.4. Effects of the Termination of the Exploitation Period:** When, for whatever reason, the operational obligations and rights regarding any Exploitation Area end, the CONTRACTOR shall leave in good conditions the wells that for that time are in production as well as the constructions, and other real estate, all of which shall become the property of the ANH free of charge, together with the easements and assets acquired to the benefit of the exploitation up to the Point of Delivery, even if those assets are outside the Exploitation Area. Regarding the chattels exclusively destined to the service of this Exploitation Area, if the termination occurs before the first eighteen (18) years of the Exploitation Period, the CONTRACTOR shall have the obligation to offer them in sale to the ANH at their book value. If in a term of three (3) months as of the date of the offer the ANH has not given its affirmative answer, the CONTRACTOR can freely dispose of them. If the termination occurs after the first eighteen (18) months of the Exploitation Period, those chattels shall pass to the ANH free of charge. The ANH shall establish, out of the wells in production at that time, which ones must be abandoned and which ones shall continue in production. Any disagreement regarding the nature and destination of the Assets shall be submitted to the procedure established in Clause 27. Likewise, the CONTRACTOR has the obligation to assign to the ANH or to whomever it orders, the Environmental License and the funds required to attend to the Abandonment obligations. The application of this clause shall not be construed as a substitution of employer between the CONTRACTOR and the ANH.

CLAUSE 5 – MINIMUM EXPLORATORY PROGRAM

- 4. Minimum Exploratory Program for each phase:** Throughout the Exploration Period, the CONTRACTOR shall perform the Minimum Exploratory Program of each phase described in Exhibit B hereto. For the performance of the obligations in the Minimum Exploratory Program, the Exploratory Wells proposed by the CONTRACTOR must be Exploratory Wells for a new field (of the A – 3 kind) or Exploratory Wells that form part of an Evaluation Program as per the provisions of Clause 7 (Section 7.3.b) hereof. In all other cases, the Exploratory Well proposed by the CONTRACTOR must be previously accepted by the ANH.
- 5.1. Exploratory Works Programs:** The CONTRACTOR undertakes to submit to the ANH the Exploratory Works Program for the phase to be started, at least eight (8) calendar days before the start of each phase of the Exploration Period. For the first phase, the CONTRACTOR must submit the Exploration work Program in a term of thirty (30) Calendar Days as of the Effective Date.
- 5.2. Amendments of the Minimum Exploratory Program**
- 5.2.1. Throughout the Current Phase:** Throughout the first half of the term of any phase of the Exploration Period other than the first phase, the CONTRACTOR will be entitled to swap the acquisition and processing of a seismic program contained in the Minimum Exploratory Program

initially submitted for the current phase, by the drilling of one or more Exploratory Wells or by the acquisition and processing of a seismic program of more modern technology, provided that the financial effort of the new Minimum Exploratory Program is equal to or greater than the one initially submitted for the relevant phase. In this case, the CONTRACTOR shall inform the ANH, previously and in writing, of the substitution of Exploratory Operations that it intends to do.

- 5.2.2. For the Next Phase:** If after the drilling of an Exploratory Well that turns out to be dry the CONTRACTOR considers that the expectations of the Contracted Area do not justify the drilling of one (1) Exploratory Well contained in the Minimum Exploratory Program of the next phase of the Exploration Period, the CONTRACTOR can replace such drilling for the purchase and processing of a seismic program, provided that the financial effort of the new Minimum Exploratory Program is equal to or greater than the one initially submitted for the relevant phase and that the CONTRACTOR informs the ANH, previously and in writing, of the substitution it intends to do.
- 5.3. Additional Exploration:** The CONTRACTOR can carry out Exploration Operations additional to those contained in the Minimum Exploratory Program or in the Subsequent Exploratory Program, and it shall not mean the amendment of the term agreed for the execution of the Minimum Exploratory Program or of the Subsequent Exploratory Program of the current phase or of the subsequent phases. To exercise this right, the CONTRACTOR shall previously inform the ANH of the additional Exploration Operations that it intends to perform. If those Exploration operations are those defined in the Minimum Exploratory Program of the next phase, the ANH shall credit such Exploration Operations to the fulfillment of the exploratory commitments agreed upon for the next phase. Otherwise, if the CONTRACTOR wishes that the additional Exploration Operations are accounted for the performance of the exploratory commitments agreed upon for the subsequent phase, if there is one, it must request it in writing to the ANH who, at its sole discretion, shall decide whether or not to accept said credit. In case that the application is accepted by the ANH, it shall establish the manner to credit, the additional Exploration Operations done, in whole or in part, to the next phase of the Exploration Period.
- 5.4. Problems during the drilling of Exploratory Wells:** During the drilling of an Exploratory Well of the Minimum Exploratory Program or of the Subsequent Exploratory Program, and before reaching the depth targeted, if non - controllable geological problems arise, such as cavities, abnormal pressures, impenetrable formations, severe circulation losses or other conditions of a technical nature that prevent continuing the drilling of the Exploratory Well, in spite of the effort used by the CONTRACTOR to continue with the drilling works according to the Oil Industry's Good Practices, the CONTRACTOR can request the ANH to deem the drilling operation as fulfilled by submitting a technical report describing the situation presented and the efforts used to overcome the problem. The aforementioned report must be submitted to the ANH in a term no longer than fifteen (15) Calendar Days as of the date in which the aforementioned non – controllable problem first appeared. If the ANH accepts that the CONTRACTOR calls off the drilling operations of the well in question, it must be abandoned or completed until the reached depth, and the obligation of the Minimum Exploratory Program or the Subsequent one pertaining to said well shall be deemed as complied with.

CLAUSE 6 - SUBSEQUENT EXPLORATORY PROGRAM

- 5. Subsequent Exploratory Program:** At the end of the Exploration Period and provided that there is at least one Assessment Area or one Exploitation Area or one Discovery made by the Contractor in the last phase of the Contracted Area's Exploration Period, the CONTRACTOR can keep fifty per cent (50%) of the contracted area (excluding the Assessment and Exploitation Areas) to do, in the retained area but outside the Assessment and Exploitation Areas, a Subsequent Exploratory Program. In this case, the following procedure will apply:
- a) Prior to the date of termination of the last phase of the Exploration Period, the CONTRACTOR shall inform the ANH, in writing, of its intention to carry a Subsequent Exploratory Program out.
 - b) The notice must describe the Exploration operations that make up the Subsequent Exploratory Program that the CONTRACTOR undertakes to complete, dividing the program in two (2) phases, each one of two (2) years, the first one starting on the end date of the last phase of the Minimum Exploratory Program. Each one of the phases of the Subsequent Exploratory Program must at least contain the same Exploratory Operations agreed upon for the last phase of the Minimum Exploratory Program.
 - c) Having complied, on a timely manner, with the obligations in the first phase of the Subsequent Exploratory Program, the CONTRACTOR can opt for not going on with the second phase, which means the devolution of all of the areas kept for these purposes, or it can opt for continuing with the second phase, in which case it shall be obligated to hand back fifty per cent (50%) of them only, excluding the existing Assessment and Exploitation Areas. The CONTRACTOR will inform the ANH in writing of its decision within one month from the termination of the first phase.

The hand back of the areas the subject matter of this clause is without prejudice to the existing Evaluation Areas and Exploitation Areas.

- 6.1.** At the end of the Subsequent Exploratory Program, the contracted area shall be reduced to the Assessment Areas and / or Exploitation Areas existing at that time.

CLAUSE 7 – DISCOVERY AND ASSESSMENT

- 6. Notice of Discovery:** At any time within a term of four (4) months after the end of the drilling of any Exploratory Well whose results indicate that a Discovery has been made, the CONTRACTOR must inform it to the ANH in writing, accompanying the notice with a technical report containing the results of the tests made, the description of the geological aspects and the analyses made to fluids and rocks in the manner ordered by the Ministry of Mines and Energy or any other authority that takes its place.

Paragraph: If the Discovery is of Not – Associated Natural Gas, or of Heavy Liquid Hydrocarbons, the CONTRACTOR must likewise hand over the calculations and all other supporting data that it would have submitted to the Ministry of Mines and Energy or to any other authority that takes its place for the purposes of classification.

7.1. Submission of the Assessment Program: If the CONTRACTOR considers that the Discovery has commercial potential, it shall submit and perform an Assessment Program regarding that Discovery, according to the provisions of this clause. If the Discovery occurs during the Exploration Period, the CONTRACTOR shall submit the Evaluation Program within six (6) months after the end of the drilling of the Exploratory Well that made the Discovery and, anyway, prior to the end of the Exploration Period. If the Discovery is the result of the execution of the Subsequent Exploratory Program, the CONTRACTOR shall submit the Assessment Program within six (6) months after the end of the drilling of the Exploratory Well that made the Discovery and, anyway, prior to the next devolution of areas subject of Clause 6 hereof.

7.2. Contents of the Assessment Program: The Assessment Program must at least include:

- a) The map, with coordinates, of the Evaluation Area;
- b) The description and goals of each one of the Assessment Operations and the data that it intends to obtain to establish whether or not the Discovery can be declared as a Commercial Field. If in the Assessment Programs performed throughout the Exploration Period the CONTRACTOR includes the drilling of Exploratory Wells, it can credit not only the compliance with the Minimum Exploratory Program but also of the relevant Assessment Program with the drilling of two (2) Exploratory Wells, provided that it ends before the end date of the Assessment Program in which they were included or of the phase of the Exploration Period to which those wells pertain, whichever is closer.
- c) The total budget of the Assessment Program, discriminated by years.
- d) The total term of the Assessment Program, which cannot last more than two (2) years when it includes the drilling of Exploratory Wells, or of one (1) year in all other cases, term that will be counted as from the submission to the ANH and it must contemplate the estimated times required to obtain the permits that must be issued by other authorities.
- e) The schedule of the Assessment Operations within the term of section d) above.
- f) The information on destination of the hydrocarbons and other fluids that the CONTRACTOR expects to recover as a result of its Assessment Operations.
- g) A proposal of Point of Delivery for the ANH to consider.

7.3. Extension of the term of the Assessment Program: If the CONTRACTOR decides to drill Exploratory Wells that have not been included in the initial Assessment Program, the ANH will extend the term of the Assessment Program for an additional term that shall not exceed one (1) year, provided that the following conditions are met:

- a) That the CONTRACTOR makes the relevant written application at least two (2) months before the date of expiration of the initial term;

- b) That the CONTRACTOR is diligently performing the Assessment Operations set forth in the Assessment Program.
- c) That the extension requested is justified by the time required for the drilling and the tests of the additional Exploratory Well or Wells, and
With the extension request the CONTRACTOR shall submit to the ANH the documents in which the application is based.

7.4. Amendments of the Assessment Program: At any time during the six (6) months after the date of submission of the Assessment Program to the ANH, the CONTRACTOR may amend it, for which it will timely inform the ANH and it shall adapt the total term thereof as per Section 7.3d of this clause, and it will not amend the start date established.

7.5. Results of the Assessment Program: The CONTRACTOR shall file with the ANH a full report of the results of the Assessment Program no later than three (3) months after the date of termination thereof. The report shall at least include the geological description of the Discovery and its structural configuration, the physical properties of the rocks and fluid present in the deposits associated to the Discovery, the pressure, volume and temperature analysis of the fluids in the deposits, the production capacity (per well and for the entire Discovery), and an estimate of the hydrocarbons' retrievable reserves.

Paragraph: In case that the discovery is of non – Associated Natural Gas, or of Heavy Liquid Hydrocarbon, and at any time throughout the second half of the term of the Assessment Program, the CONTRACTOR can apply with the ANH for the extension of the Assessment Program for up to two (2) more years in order to do feasibility studies for the construction of infrastructure, production methods and / or market development. In these cases, the application shall include, in the Assessment Program, the data related to the feasibility studies that the CONTRACTOR deems necessary to do. At the end of the extension granted, the CONTRACTOR shall deliver the conclusions and recommendations of the Feasibility Studies to the ANH.

7.6. This clause shall only be applicable for the Exploratory Wells that made the discovery, drilled by the CONTRACTOR outside the areas designated as of Assessment or Exploitation. Hence, when the new volumes of Hydrocarbons found are part of one same Assessment or Exploitation Area, no Assessment Period shall be available.

CLAUSE 8 – DECLARATION OF COMMERCIALITY

7. Notice: During the three (3) months that follow the expiration of the term stipulated for the execution of the Assessment Program or upon the expiration of the term agreed upon according to the Paragraph to Section 7.6 of Clause 7, if applicable, the CONTRACTOR shall furnish the ANH with a written statement containing, in a clear and accurate way, its unconditional decision to commercially exploit that Discovery or not. If yes, the Discovery shall be construed as a Commercial Field as of said statement.

- 8.1. Waiver of Rights if negative:** If the CONTRACTOR does not furnish the ANH with the statement in the given term, it shall be deemed that the CONTRACTOR has concluded that the Discovery is not a Commercial Field. If the statement contains a negative decision or if no statement is made, the CONTRACTOR accepts that no right was generated in its favor and, consequently, waives to claim any rights on the Discovery.

CLAUSE 9 – EXPLOITATION PLAN

- 8. Submission and Contents:** No later than three (3) months after the submission of the Declaration of Commerciality subject of Clause 8, the CONTRACTOR shall submit to the ANH the initial Exploitation Plan, which shall at least contain the following information:

- a) The map with the coordinates of the Exploitation Area
- b) The calculation of the reserves and of the cumulative production of Hydrocarbons, classified by type of Hydrocarbon.
- c) The general scheme projected for the Development of the Commercial Field, including a description of the program for the drilling of wells for the development of extraction methods, of the respective facilities and of the processes to which the extracted fluids shall be submitted before the Point of Delivery.
- d) The Hydrocarbons' production annual forecast and its sensitivities, using the optimal production rate that allows achieving the maximum economic recovery of the reserves.
- e) The identification of the key factors for the execution of the Exploitation plan, such as environmental, social, economic, logistic issues and the options to manage them.
- f) A proposal of Point of Delivery for the ANH to consider.
- g) A proposal of a basket of maximum three (3) crude oils of a similar quality for the purposes of the calculation of the High Prices' Fees described in Clause 16.
- h) An Abandonment Program for the purposes of Clause 30.

- 9.1. Delivery of the Exploitation Plan:** The ANH shall consider the Exploitation Plan as received when the CONTRACTOR hands all the aforementioned data over to the ANH. If the ANH does not receive the Exploitation Plan with all the information set forth above within fifteen (15) Calendar Days after its submission, it can request the delivery of the missing data and the CONTRACTOR shall have thirty (30) calendar days counted from the receipt of the requirement to deliver it. If the ANH does not make a pronouncement in a term of fifteen (15) Calendar Days after the Submission of the Exploitation Plan by the CONTRACTOR, it shall be deemed as accepted. If the CONTRACTOR does not deliver the Exploitation Plan on the date established in the preceding section, or if the ANH does not receive the missing data in the thirty – day (30) term set forth in this Article, it will be construed as a breach of contract and Clause 28 shall apply.

- 9.2. Exploitation Area:** The Exploitation Area shall be circumscribed into a regular polygon, preferably a four – sided one, that will comprise the Commercial Field or the portion thereof within the

Contracted Area, plus a margin around the Commercial Field of no more than one (1) kilometer, provided that the Contracted Area allows it. Considering that the area of the Commercial Field contained in the Exploitation Area can vary, the Exploitation Area shall be locked – in, except for the following section.

9.3. Expansion of the Exploitation Area: Throughout the Exploitation Period of an Exploitation Area, if the CONTRACTOR establishes that a Commercial Field goes beyond the Exploitation Area but within the Contracted Area in force, it can request the ANH the expansion of said Exploitation area accompanying its application with all supporting data as required. Having done this to the ANH'S satisfaction, the ANH shall extend the Exploitation Area, and it is construed that if such expansion is overlapped with another Exploitation Area, the term of the Exploitation Period applicable to the whole Exploitation Area shall be the one of the Exploitation Area whose commerciality was first declared.

Paragraph: When the Exploitation Area requested by the CONTRACTOR as per Section 9.4 above goes beyond the Contracted Area, the ANH shall extend the Contracted Area giving to the expansion requested the contractual treatment of Assessment Area, unless respecting the requested area one of the following situations occur:

- a) That there are rights granted to somebody else for the execution of activities the same than or similar to those in this Contract.
- b) That it is in the process of negotiation or of tender for the granting of rights by the ANH.
- c) That there are restrictions ordered by competent authority that prevent to pursue the activities hereunder.

9.4. Updating of the Exploitation Plan: The CONTRACTOR shall annually adjust and submit, in the month of February of every Calendar Year and subject to the proceeding described in Section 9.2 hereof, the Exploitation Plan for each one of the Exploitation Areas existing in the Contract. When the actual production of Hydrocarbons of the Calendar year immediately before differs in more than fifteen per cent (15%) versus the annual production forecast set forth in the Exploitation plan for some Exploitation Area, the CONTRACTOR shall render the explanations that may be required.

CLAUSE 10 – EXPLOITATION WORKS PROGRAM

9. Preparation and Submission: If at the time in which the Exploitation Plan the subject matter of the ninth (9th) clause is submitted there still are more than six (6) months before the end of the current Calendar Year, the CONTRACTOR shall submit the first of the Exploitation Works for the remaining of that year. For the subsequent calendar years, the CONTRACTOR shall submit the Exploitation Works for each calendar year in the month of November of the previous Calendar Year.

10.1. Contents of the Exploitation Works Program: The Exploitation Works Program for each Exploitation Area shall at least contain:

- a) A detailed description of the Development and Production Operations Program that the contractor expects to complete during the Year with the relevant schedule, detailed by project and by Calendar Quarter, which must also include the terms required to obtain the authorizations and permits from the competent authorities as required.
- b) A monthly production forecast of the Exploitation Area for the relevant Calendar Year.
- c) An estimate of the costs (investments and expenses) for the four (4) subsequent Calendar Years or until the end of the Exploitation Period, whichever is shortest.
- d) The terms and conditions according to which it will develop the programs to the benefit of the communities in the area of influence of the Exploitation Area.

10.2. Execution and Adjustments: The Development and Production Operations of the Exploitation Works Program subject of subparagraph (a) above is mandatory. The CONTRACTOR shall start such Exploitation Operations according to the schedule submitted. Throughout the execution of the Exploitation Works Program, the CONTRACTOR can adjust said program for the current Calendar Year, provided that such adjustments do not imply the reduction of the production of more than fifteen per cent (15%) versus the initial forecast. The adjustments cannot be made with a frequency of less than three (3) months, unless in emergencies. The CONTRACTOR shall inform, previously and in writing, any adjustment to the Exploitation Works Program.

CLAUSE 11 – CONDUCTION OF THE OPERATIONS

10. Autonomy: The CONTRACTOR shall have the control of all operations and activities it deems necessary for the technical, efficient and economical Exploration of the Contracted Area and for the Assessment and Exploitation of the Hydrocarbons found in it. The CONTRACTOR shall plan, prepare, carry out, and control all the activities with its own means and with technical and managerial autonomy, in conformity to the Colombian laws and observing the Good Practices of the Oil Industry. The CONTRACTOR shall develop the activities either directly or through subcontractors.

11.1. Responsibility: The CONTRACTOR shall perform the operations hereunder in a diligent, responsible, efficient and technically and economically appropriate manner. It shall ensure that all of its subcontractors comply with the terms of this contract and with the laws of Colombia. The CONTRACTOR shall be the sole responsible for the losses and damages caused because of the activities and operations derived hereof, even those caused by its subcontractors, and it is hereby construed that it shall nor ever be responsible for judgment errors, or for losses or damages that did not result from gross negligence or willful misconduct. When the CONTRACTOR enters into subcontracts, the subcontracted works and services shall be executed in its name, as the CONTRACTOR shall continue being the direct responsible for all obligations set forth in the Subcontract and derived thereof, and it shall not be released from them because of the Subcontracts. The ANH shall not assume the responsibility for this concept, not even under joint and several liability.

- 11.2. Obtaining Permits:** The CONTRACTOR has the obligation to obtain, at its own cost and risk, all licenses, authorizations, permits and other relevant rights according to the law, required to carry out the operations hereunder.
- 11.3. Losses and damages of the Assets:** All costs and expenses required to replace or repair damages or losses of assets or equipment caused because of fire, flood, storms, accidents or other similar occurrences shall be the CONTRACTOR'S risk. The CONTRACTOR shall inform the ANH of the losses and damages occurred at the earliest opportunity after the occurrence.

CLAUSE 12 - ROYALTIES

- 11. Collection:** The CONTRACTOR shall make available for the ANH, at the Point of Delivery, the percentage of the production of Hydrocarbons set forth in the relevant Royalties' Law. The collection of the royalties shall be made in cash or in kind, as determined by the competent authority.
- 12.1. Payment of the Participations:** The ANH shall make the payments of their share of the royalties to the entities established by the law, and it shall be the sore responsible to do the payment.
- 12.2. Collection in Kind:** When the collection of the royalties is made in kind, the CONTRACTOR shall deliver to the ANH the relevant amount of Hydrocarbons, for which the parties shall agree the procedure in the schedule of deliveries and all other issues required. Anyway, the ANH shall have one (1) Month to remove that quantity. If at the expiration of this term the ANH has not removed the volume of the royalties, and if there is a chance to store them in the CONTRACTOR'S facilities, the CONTRACTOR commits to store the hydrocarbons for up to three (3) consecutive months and the ANH shall pay a Storage Fee that, in each case, shall be agreed upon by the parties. At the end of this last term, the CONTRACTOR can market said volume, as per the following section.
- Paragraph:** If the storage is not possible, the CONTRACTOR can continue production from the field and dispose of the royalties' volume, crediting it to the ANH for its subsequent delivery the volume of the royalties that the ANH was entitled to remove but did not.
- 12.3. Marketing of the volume of Royalties:** Whenever the ANH deems it convenient, and provided that the regulations so allow, the CONTRACTOR shall market the portion of the production of Hydrocarbons pertaining to Royalties and it shall hand over to the ANH the money from such sales. For these purposes, the Parties shall agree upon the particular terms of the commercialization, but in any case the CONTRACTOR shall use its best efforts to market such production at the highest price available in the market. The ANH shall pay the contractor the direct expenses as well as a reasonable marketing fee to be agreed upon by the parties.
- 12.4. Collection in Cash:** When the CONTRACTOR has to pay the royalties in cash, it shall deliver to the ANH the relevant amounts in the terms established by the competent authority. In case of late payment, the CONTRACTOR shall pay the ANH the amount required to cover the amount owed, the late payment interests due and the expenses incurred to obtain the payment.

CLAUSE 13 – MEASURING

- 12. Measuring:** The CONTRACTOR shall do the measuring, sampling and quality control of the Hydrocarbons produced, and it shall maintain all equipment or measuring instruments duly calibrated as per the standards and methods accepted by the Oil Industry's Good Prices and according to the legal and regulatory provisions in force, performing the assays required and doing all corrections pertinent for the liquidation of the net volumes of Hydrocarbons received and delivered in standard conditions. The CONTRACTOR shall adopt all actions required to preserve the integrity, reliability and safety of the facilities and the control equipment or instruments. Besides, it shall keep, for the term ordered by the Commerce Code and all other pertinent norms, the records of the periodic calibration of said instruments or equipment and of the daily measurements of production and consumption of Hydrocarbons and fluid in each Commercial Field for the revision of the ANH and of the competent authorities. The ANH shall have the right to inspect the measuring equipment installed by the CONTRACTOR as well as all measuring units in general.
- 13.1. Common Facilities:** When two or more production fields are served by the same development facilities, these must include a measuring system that allows establishing the production from each one of those fields.

CLAUSE 14 – AVAILABILITY OF THE PRODUCTION

- 13. Determination of Volumes:** The Hydrocarbons produced, excepting those that have been used to the benefit of the operations hereunder and those that are unavoidably wasted in those undertakings shall be transported by the CONTRACTOR to the Point of Delivery. The Hydrocarbons shall be measured as per the procedure established in Section 13.1 above, and, based on such metrics, the volumes of royalties mentioned in clause 12 shall be figured out, as well as the remaining Hydrocarbons that belong to the CONTRACTOR.
- 14.1. Availability:** As of the Point of Delivery, and notwithstanding the legal provisions that govern these issues, the CONTRACTOR shall have the liberty to sell the Hydrocarbons in the Country or to export them, or to dispose of them in any other way.

CLAUSE 15 – NATURAL GAS

- 14. Utilization:** The CONTRACTOR shall have the obligation to prevent the wastage of the natural gas extracted from a field and, in conformity to the legal and regulatory provisions in force on the matter, before the Point of Delivery it can be used as fuel for the operations, as source of power for the maximum final recovery of the reserves of Hydrocarbons, or to confine it in the same deposits to use it for such purposes throughout the life of the contract.

15.1. Use of the Associated Natural Gas: In case that the CONTRACTOR discovers one or more commercial fields with Associated Natural Gas, it must submit to the ANH, within three (3) years after the commencement of the exploitation of each Commercial Field, a project for the use of the associated Natural Gas. If the CONTRACTOR does not comply with this obligation, the ANH can freely dispose of the associated Natural Gas from such fields, subject to the legal provisions in force.

CLAUSE 16 – ANH'S CONTRACTUAL ECONOMIC RIGHTS

15. Fees for the use of the Subsoil: The use of the subsoil by the CONTRACTOR shall accrue the following fees in favor of the ANH:

16.1.1. Exploration Areas: As of the second phase of the Exploration Period and for each Phase, the CONTRACTOR shall acknowledge and pay the ANH a fee for a value expressed in dollars of the United States of America resulting from multiplying the number of hectares and fraction thereof of the Contracted Area, excluding the Exploitation Area, by the relevant amount in the following table. This payment shall be made within one month after the commencement of the respective phase:

Size of the Area	For the first 100.000 hectares		For each hectare in excess of 100.000 hectares	
	≤ 12 Months	> 12 Months	≤ 12 Months	> 12 Months
In Polygons A & B	0.75	1.0	1.0	1.5
Outside the Polygons	0.5	0.75	.075	1.0
Offshore Areas	0.25			

16.1.2. Assessment and Exploitation Areas: The CONTRACTOR shall acknowledge and pay the ANH a fee for the amount, expressed in dollars of the United States of America, resulting from multiplying the production of Hydrocarbons corresponding to the CONTRACTOR as per Clause 14 by ten cents of one dollar of the United States of America (USD \$ 0.10) per barrel of liquid hydrocarbons. This amount shall be annually increased according to the $I_{(n-2)}$ defined in Clause 16.2 as of the first day of January of year 2006. For natural gas, this amount shall be of one cent of one dollar of the United States of America (USD \$0.01) for every one thousand cubic feet (1000 CF). This payment shall be made in semiannual installments, in arrears, within the first month of the next semiannual period.

16.2. High Prices' Fees:

For Liquid Hydrocarbons: Starting when the cumulative production of each Exploitation Area, including the volume of royalties, is higher than five (5) million Barrels of Liquid Hydrocarbons, and in the event that the price of the benchmarking "West Texas Intermediate" (WTI) crude oil

exceeds the **Po** Base Price, the CONTRACTOR shall pay the ANH a sum expressed in dollars of the United States of America and payable per Calendar Month in arrears, within the thirty (30) days after each end date.

For Natural Gas: Five (5) years after the commencement of the exploitation of the field as per the approval resolution issued by the competent authority, and in the event that the price of the benchmarking "U. S. Gulf Coast Henry Hub" Natural Gas exceeds the **Po** Base Price, the CONTRACTOR shall pay the ANH a sum expressed in dollars of the United States of America and payable per Calendar Month in arrears, within the thirty (30) days after each end date.

The sum to be paid for each Exploitation Area shall be the one resulting from the application of the following formula:

$$\text{Payment to the ANH: } \frac{\text{Value of the Hydrocarbons at the Point of Delivery}}{\text{"A" Factor}} \times \frac{\text{Volume of Hydrocarbons of the Contractor}}{\text{P}} \times \frac{\text{P} - \text{Po}}{\text{P}} \times 30\%$$

Where:

Value of the Hydrocarbons at the Point of Delivery:

For Liquid Hydrocarbons:

For the purposes of this formula, it shall be the price of reference for the relevant Calendar Month expressed in dollars of the United States of America per Barrel USD \$ / Bl) of a basket of maximum three (3) crude oils of a quality similar to those from each Exploitation Area presented by the CONTRACTOR in the Exploitation plan and agreed upon with the ANH and adjusted for the Point of Delivery by a prearranged margin.

If, having applied the procedure for the determination of the Value of the Hydrocarbons as per the preceding paragraph, differences arise, upwards or downwards, between the price of reference of the basket and the actual sale price in excess of three per cent (3%), the party that considers itself affected can request a revision of the basket or of the adjustment margin. For these purposes, the actual sale price of the Liquid Hydrocarbons produced in the Exploitation Area for the relevant calendar month shall be the weighed average of the sale prices agreed by the CONTRACTOR with buyers not related through financial links or in any other corporate manner and that, anyway, the transactions agree with the usual commercial practices deducting the transportation and transshipment costs between the Point of Delivery and the reference sale price according to the rates established by the Ministry of Mines and Energy or whoever takes its place.

When the CONTRACTOR sells the liquid hydrocarbons to be refined to serve the internal demand, the provisions of Section 16.5 hereof shall apply.

For Natural Gas:

For the purposes of this formula, it shall be the actual sale price of the Natural Gas for the production of the relevant calendar month, expressed in dollars of the United States of America per million of British Thermal Unit (BTU) USD \$ / MMBTU) agreed upon by the CONTRACTOR with buyers, subtracting the transportation and processing costs between the Point of Delivery and the actual sale point.

The ANH can revise this price at any time.

Volume of the CONTRACTOR'S Hydrocarbons:

It is the volume of Hydrocarbons, expressed in Barrels for liquid hydrocarbons and in British Thermal Unit BTU for Natural Gas that corresponds to the CONTRACTOR as per Clause 14 in a given Calendar Month.

P

For liquid Hydrocarbons it is average price per crude oil barrel – “West Texas Intermediate” (WTI) benchmark expressed in dollars of the United States of America per barrel (USD \$ / Bl), and for Natural Gas it is the average price for the natural gas “U. S. Gulf Coast Henry Hub” benchmark expressed in dollars of the United States of America per million of British Thermal Unit BTU (USD \$ / MMBTU). These averages are for the relevant calendar month whose specifications and quotations are published in media of an acknowledged international prestige.

Po

For Liquid Hydrocarbons, it is the average price per barrel of the barrel – “West Texas Intermediate” (WTI) benchmark expressed in dollars of the United States of America per Barrel (USD \$ / Bl) and for Natural Gas it is the average price for natural gas expressed in dollars of the United States of America per million of British Thermal Unit BTU (USD \$ / MMBTU) according to the following table:

API Gravity of the Liquid Hydrocarbons Produced	Po (USD \$ / Bl)
> 15 and ≤ 22	\$28
> 22 and ≤ 29	\$27
> 29	\$26
Discoveries located at more than 300 meters deep in the water	\$32
Natural Gas produced exported – straight-line distance between Point of Delivery and reception point in the destination country, in Kilometers	Po USD \$ / MMBTU
> 0 and ≤ 500	\$ 6
> 500 and ≤ 1000	\$ 7
> 1000 or LNG Plant	\$8

For Exporting Heavy Liquid Hydrocarbons with an API Gravity of more than ten degrees (10°) the Po shall be of forty dollars of the United States of America per barrel (USD \$ / Bl) and for Heavy Liquid Hydrocarbons with an API gravity equal to or lower than ten degrees (10°), the CONTRACTOR shall not pay the ANH the High Prices' Fee. For the natural gas destined for the domestic consumption of the country, in the event its price is regulated by the Energy and Gas Regulatory Commission – CREG – or the entity that replaces it, the CONTRACTOR shall not pay the ANH any High Prices Fee; otherwise, the parties shall agree the natural gas benchmark and the amount of the Po and they shall enter into the relevant agreement.

The Po base price shall be annually adjusted as of the first (1st) day of January of year 2006, according to the following formula:

$$Po = Po_{(n-1)} \times (1 + I_{(n-2)}),$$

Where:

Po_(n-1): It is value of Po for the immediately previous calendar year

I_(n-2): It is the annual variation, expressed as a fraction, of the Producers' Price Index of the United States of America during the calendar year, two years before the one for which the calculation is made, published by the Labor Department of that country.

The aforementioned calculation shall be made on December of each year.

Paragraph: In the event that the price of the “West Texas Intermediate” crude oil benchmark or of the natural gas “U. S. Gulf Coast Henry Hub” benchmark (P) are no longer acknowledged as international price benchmark, the ANH shall choose the new benchmark for crude oil or natural gas and it shall amend the table based on the new index, maintaining the equivalencies with the

Po values for the "West Texas Intermediate" crude oil benchmark or of the natural gas "U. S. Gulf Coast Henry Hub".

At least three (3) months in advance, the ANH can request the CONTRACTOR, in writing for the payment of this right to be made in kind for a term of no less than six (6) months. The CONTRACTOR shall accept this request provided that it does not affect the commercial commitments it has contracted. The volume that corresponds to the ANH shall be the one resulting from calculating the "A" Factor.

- 16.3. Production Tests:** The liquid Hydrocarbons obtained as a result of the Production Tests performed by the CONTRACTOR shall also accrue the fees subject of the preceding sections, provided that the conditions of item 16.2 are met.
- 16.4. Participation in the Production during the Extension of the Exploitation Period:** In all cases of extension of the Exploitation Period of an Exploitation Area, the CONTRACTOR shall acknowledge and pay the ANH, as fee of participation in the production, a sum equal to ten per cent (10%) of the value of the production of light Liquid Hydrocarbons at the Point of Delivery, or five per cent (5%) in the case of Natural Gas Not – Associated or Heavy Liquid Hydrocarbons obtained by the CONTRACTOR as of the date of expiration of the initial term of the Exploitation Period and valued at the Point of Delivery, after deducting the percentage of royalties. The Economic Rights subject of sections 16.1.2 and 16.2 shall not be accrued on this participation. Throughout the extension of the Exploitation Period the fees for the use of the subsoil and the high prices' fees, respectively, subject of sections 16.1.2 and 16.2, shall only be accrued on the CONTRACTOR'S volume, after subtracting the right of participation set forth in this section.
- 16.5. Prices for the Internal Supply:** When the CONTRACTOR sells its crude oil to serve the domestic refining needs, the prices shall be figured out based on the international price as established in Resolution Number 18 – 1709 of 23 December of 2003 of the Ministry of Mines and energy, or of any other legal or regulatory provision that amends or replaces it.

CLAUSE 17 – UNIFICATION

Whenever the economically exploitable deposit extends, in an uninterrupted manner, into other Area or Areas outside the Contracted Area, the CONTRACTOR, in consensus with the ANH and all other interested parties, must enforce, upon the approval of the competent authority, a unified cooperative exploitation plan subject to the provisions of the Colombian legislation.

CLAUSE 18 – OWNERSHIP OF THE ASSETS

16.

- 17.1. The CONTRACTOR** shall transfer to the ANH, free of charge, upon the devolution of the area or at the termination of the contract, when any of them occur after the first eighteen (18) years of the Exploitation Period, all rights derived from contracts under the modality of project finance such as leasing, "Build, Operate, Maintain and Transfer" (BOMT), "Build, Own, Operate and Transfer" (BOOT), "Modernize, operate and Transfer" (MOT) and the likes, which establish the obligation to transfer the ownership of the assets, equipment and facilities to the CONTRACTOR

at their termination, whenever said contracts have been entered into to develop the Exploitation Period of the respective area. Anyway, in the event that said contracts are entered into for a term longer than the Exploitation Period, they must be previously authorized by the ANH.

- 17.2. Inventories:** The CONTRACTOR shall make physical inventories of the equipment and assets pertaining to the Exploitation Operations, with reasonable intervals of at least three (3) Calendar Years, classifying them as owned by the CONTRACTOR or of third parties. The ANH shall be entitled to be represented whenever such inventories take place. For these purposes, the CONTRACTOR shall inform the ANH at least fifteen (15) calendar Days in advance.
- 17.3. Disposal of the Assets:** The CONTRACTOR can dispose of the assets or equipment located up to the Point of Delivery and that are not indispensable to maintain the existing conditions of exploitation. Notwithstanding the foregoing, after the first eighteen (18) years of the Exploitation Period of every Exploitation Area or whenever eighty per cent (80%) of the reserves have been exploited, whichever come first, the CONTRACTOR shall require the prior approval of the ANH to do so.

CLAUSE 19 – INFORMATION SUPPLY AND CONFIDENTIALITY

- 17. Technical Information:** The CONTRACTOR shall keep the ANH permanently and opportunely informed of the progress and results of the operations. Therefore, besides the documents required in other clauses hereof, the CONTRACTOR shall deliver to the ANH, as it gets produced and before the date of expiration of each one of the phases of the Exploration Period and per Calendar Year during the Exploitation Period, all the information of a scientific, technical and environmental nature obtained in compliance with this Contract. This Exploration and Exploitation information shall be delivered to the ANH according to the Manual for the Supply of Exploration and Exploitation Data.
- 18.1. Confidentiality of the Information:** The parties agree that all data and information produced, obtained or developed as a result of the operations in this Contract are considered as strictly confidential during the five (5) Calendar Years after the end of the Calendar Year in which they were produced, obtained or developed, or until the end of the Contract or at the time of the partial devolution of the area regarding the information acquired in the returned areas, whichever comes first. For the construal based on the data obtained as a result of the operations in this contract, this term shall be of twenty (20) Calendar Years as of the date of the obligation to deliver it to the ANH, or until the end of the contract or at the time of the partial devolution of areas regarding the data acquired in the Returned areas, whichever comes first. This stipulation shall not apply to the data or information that the Parties must furnish according to the legal and regulatory provisions in force, or to those required by its subsidiaries, consultants, contractors, auditors, legal advisors, financial entities and competent authorities with jurisdiction on the parties or their subsidiaries, or by provisions of the stock exchanges in which the CONTRACTOR'S shares or those of affiliated companies are registered; however, it must communicate the delivery of information to the other Party. The restrictions to the disclosure of information shall not prevent The CONTRACTOR from supplying data or information to companies interested in an eventual assignment of rights regarding the Contracted Area and provided that those companies enter into the relevant confidentiality

agreement enforcing the provisions of this clause. The ANH commits not to give to third parties any data or information obtained as a result of the operations pursued by the CONTRACTOR, excepting whenever it is required to comply with any legal provision applicable to the ANH, or pursuant to its duties. In all other cases, the ANH shall require the prior authorization of the CONTRACTOR.

- 18.2. Ownership of the Information:** Once the confidentiality period established in the preceding clause has lapsed, it is construed that the CONTRACTOR conveys to the ANH all the rights on said data and its interpretations but the CONTRACTOR does not lose the right to utilize said information. As of that moment, the ANH is free to use that information.
- 18.3. Information Meetings:** At any time throughout the term of this contract the ANH can summon the CONTRACTOR to information meetings.
- 18.4. Semiannual Executive Report:** Besides the information subject of other clauses hereof, the Manual for the Supply of Information and the one required by the Colombian legislation. The CONTRACTOR shall hand over to the ANH the basic and summarized information of issues such as prospection, reserves, actual production and forecast, Exploration, Evaluation or Exploitation Operations executed and projected for the next Calendar Year, staff, industrial safety, environment and communities, national content of the contracts, among other. The report of the second half of the year shall be the Annual operations Report and the program to be executed in the next calendar year. These reports shall be delivered within sixty (60) days after the end of each calendar semi-annual period.

CLAUSE 20 – INSPECTION AND FOLLOW UP

- 18. Visits to the Contracted Area:** Throughout the term of this contract the ANH, at its own risk at any time and for the procedures deemed as appropriate, can visit the Contracted Area to inspect and follow up the activities of the CONTRACTOR and of the subcontractors, directly related to this contract and to ensure the compliance with this Contract. Likewise, it can verify the accuracy of the information received. When the inspector detects faults or irregularities committed by the CONTRACTOR, the inspector can formulate observations which must be answered by the CONTRACTOR, in writing and in the term set forth by the ANH.

The CONTRACTOR, at its own cost, shall make available for the representative of the ANH, all transport, lodging, catering facilities and all other services in the same conditions in which they are supplied to its own staff, if required.

- 19.1. Delegation:** The ANH can delegate the inspection and follow up of the operations in the Contracted Area in order to ensure that the CONTRACTOR is complying with the obligations undertaken hereunder and the Colombian legislation. The absence of inspection and follow up activities of the ANH does not exempt the CONTRACTOR in any way from the compliance with the obligations contracted hereunder, nor does it imply a reduction thereof.

CLAUSE 21 - INSURANCE

- 19. Insurance:** The CONTRACTOR shall purchase all insurance required by the laws of Colombia as well as any other usual insurance according to the Oil Industry's Good Practice. Likewise, it shall require that each of its contracting working pursuant to this contract, to purchase and keep in force all insurance it deems as necessary. The expenses required by the contracting and validity of this insurance are on the CONTRACTOR'S risk and expense.
- 20.1. Labor Liabilities Insurance:** The CONTRACTOR shall purchase an insurance policy to guaranty the payment of wages, benefits and indemnifications and all other labor liabilities for eventual judicial convictions derived from the claims of the workers hired by the CONTRACTOR in his capacity as true and only employer thereof. The validity of the policy shall not be of less than three (3) years as of the date of termination of this contract and the insured value shall be equal to ten per cent (10%) of the payroll of the CONTRACTOR'S staff deployed for the performance of this Contract in the year prior to its termination.

CLAUSE 22 - GUARANTEES

- 20. Purpose of the guaranty:** The CONTRACTOR **must** give the ANH, in the form, term and conditions set forth in the contract, all guarantees to ensure the performance and correct execution of all obligations of each phase of the Exploration Period and of the Subsequent Exploratory Program, if there is one, as well as all other activities pertaining to those obligations. This guaranty shall not be considered as a penalty clause whatsoever.
- 21.1. Form of the Guarantees:** The CONTRACTOR shall establish, at its own cost and expense, one or several unconditional and irrevocable "stand – by" letters of credit, payable on demand, with a bank or financial institutions legally established in Colombia, or another instrument or another institution previously accepted by the ANH.
- 21.2. Delivery of the Guarantees:** The CONTRACTOR shall hand over to the ANH the guarantees subject of this clause as per the essential terms of the form contained in Exhibit C hereto at least eight (8) Calendar days before the date of commencement of each phase of the Exploration Period or of the Subsequent Exploratory Program, as the case may be. For the first phase, the CONTRACTOR shall deliver the guaranty in a term of fifteen (15) calendar days after the date of signature of the Contract. If for reasons beyond the control of the CONTRACTOR, duly supported, it cannot deliver the guarantees to the ANH in the term stipulated above, the ANH, upon request of the CONTRACTOR, may extend the date of delivery. The CONTRACTOR'S failure to hand over the guarantees within the terms hereof shall be a default of the contract.
- 21.3. Amount of the Guarantees:** The CONTRACTOR shall give the guarantees pertaining to each phase of the Exploration Period or of the Subsequent Exploratory Program, as the case may be, for ten per cent (10%) of the amount of the budget of the Phase of the Minimum Exploratory Program, as the case may be, expressed in dollars of the United States of America and payable in Colombian pesos. Under no circumstances will the amount of the guaranty for each phase be lower than one hundred thousand dollars of the United States of America (USD 100.000), or higher than three million dollars of the United States of America (USD \$ 3.000.000).

- 21.4. Validity of the Guarantees:** Each and all of the guarantees shall be in force for the term of the phase whose obligations it is guaranteeing and three (3) more months. In the event of extensions, the guarantees must be likewise extended or substituted by other of the same value and with a minimum validity equal to the time of the extension and three (3) more months.
- 21.5. Rejection of the Guarantees:** The ANH shall reject the guarantees granted by the CONTRACTOR when these do not meet the requirements of this clause. The ANH shall have one (1) month as of the date of receipt subject of Section 22.3 to inform its rejection to the CONTRACTOR and hand him the guarantees submitted. As of that notice, the contractor shall have eight (8) calendar days to fix the guaranty. If it is not amended, the guarantees rejected shall be deemed as not delivered for the purposes of Section 22.3.
- 21.6. Effectiveness of the Guarantees:** The ANH shall make the guarantees effective whenever the CONTRACTOR breaches, in all or in part, any of the obligations guaranteed, notwithstanding the performance of all other obligations assumed. The payment of the Stand – By Letter (s) of Credit shall not release the CONTRACTOR from its obligation to indemnify the damages and losses caused by its failure to comply. The ANH reserves the right to resort to the mechanisms for the resolution of conflicts when the amount of the guaranty is not enough to cover the amount of the indemnifications.

CLAUSE 23 – SUBCONTRACTORS, PERSONNEL AND TRANSFER OF TECHNOLOGY

- 21. Subcontractors:** To perform the operations subject of this Contract the CONTRACTOR can, observing the Colombian legislation, enter into contracts, at its own cost and risk, for the procurement of goods and services, in this country or abroad. In the subcontracts, the CONTRACTOR shall include stipulations to bind the subcontractors to submit to the laws of Colombia and to the provisions of this contract.
- 22.1. Lists of Contractors and Subcontractors:** The CONTRACTOR shall keep an updated list of the works, services and supplies contracts, and it will make them available for the ANH when so required. The list must at least specify the name of the supplier, contractor or subcontractor, the purpose, value and duration of the contract.
- 22.2. National Component:** The CONTRACTOR shall try to prefer national offerors of goods and services of national origin in equal competitive conditions of quality, opportunity and price.
- 22.3. Personnel:** For all legal purposes, the CONTRACTOR shall act as the sole employer of the workers hired pursuant to the activities of this contract and, in consequence, it shall be responsible for the labor liabilities arising of the respective labor relationships or contracts, such as payment of salaries and social benefits, para – fiscal contributions, registration and contributions to the Integral Social Security System for pensions, health and professional risks according to the Law. The CONTRACTOR shall adequately and diligently train the Colombian staff required to replace the foreign personnel that the CONTRACTOR deems necessary to carry out the operations hereunder.

Anyway, the CONTRACTOR must comply with the legal provisions that establish the proportion of national and foreign employees and workers.

- 22.4. Transfer of Technology:** The CONTRACTOR undertakes to pay for or to do, at its own expense, professional training programs or through the sponsorship of investigation projects designated by the ANH in areas related to the development of this Contract and throughout its life. The training shall be related to the oil and gas industry, in technical, environmental, commercial, or legal areas, among other. The training that can be made through the integration of the professionals appointed by the ANH into the work group organized by the CONTRACTOR for the Contracted Area or for other related activities. All the training expenses, excepting the labor ones accrued in favor of the professionals receiving it, that arise because of the CONTRACTOR'S compliance with this clause shall be assumed one hundred per cent (100%) by the CONTRACTOR. The CONTRACTOR shall under no circumstances assume any costs derived from the labor relationship of the beneficiaries of the training. To comply with the obligations related to Transfer of Technology according to the provisions in this clause, the CONTRACTOR undertakes, in each one of the phases of the Exploration Period and its extensions, to carry out technology transfer programs for a value of twenty five per cent (25%) of the right for the use of the subsoil the subject matter of Clause 16 (Section 16.1.1), of the phase in progress of the Exploration Period. Regarding the Exploitation areas, the transfer of technology shall be for up to ten per cent (10%) of the amount of the fee for the use of the subsoil subject of Clause 16 (Section 16.1.2) for each Calendar Year. Under no circumstances the CONTRACTOR will be made to assume Technology Transfer expenses in excess of one hundred thousand dollars of the United States of America (USD \$ 100.000) per phase or per Calendar Year, as the case may be. The technology transfer program, including its purpose, scope, participants and place, will be previously agreed between the ANH and the CONTRACTOR.

CLAUSE 24 – OPERATOR

- 22.** Although it can assume the operation in a direct manner, the CONTRACTOR can hire a third party to act as operator, provided that it evidences experience, suitability and financial soundness. In these cases, the appointment of a third party as operator requires the final approval of the ANH.
- 23.1.** When the CONTRACTOR is made up by two or more companies, it must be informed which one of them shall perform as operator.
- 23.2.** Whenever the Contract requires more than two different operators at the same time in this Contract, the prior approval of the ANH shall be required.
- 23.3.** When the operator decides to quit, it must so inform at least ninety (90) calendar days in advance.
- 23.4.** When the operator is a third party and it is brought to the knowledge of the ANH that it has assumed negligent conducts or conducts that are against the Oil Industry's Good Practices regarding the performance of the obligation subject hereof, it shall so inform to the CONTRACTOR, who shall have a term of ninety (90) calendar days as of the date of the requirement to take the relevant corrective measures. If at the end of the aforementioned term the aforementioned conducts persist, the ANH shall demand that the CONTRACTOR changes the operator.

CLAUSE 25 – RIGHT OF ASSIGNMENT

23. Right: The CONTRACTOR is entitled, with the prior written approval of the ANH, to assign or transfer in whole or in part its interest, rights and obligations arising from this contract to another company, consortium or joint venture with the financial capacity, the technical competence, the professional capabilities and the legal capacity required to operate in Colombia.

24.1. Procedure: For such purposes, the CONTRACTOR shall file a written application with the ANH, stating the essential elements of the negotiation, such as the name of the possible assignee, the information of its legal, financial, technical and operational capacity, the value of the rights and obligations to be assigned, the scope of the operation, etc, within sixty (60) business days after the receipt of the application submitted in a complete manner. The ANH shall exercise its discretionary power to analyze the data furnished by the CONTRACTOR, after which it will make a decision, and it does not have the obligation to reason it. In the event that any of the companies that make the CONTRACTOR up is in proceedings for mergers, spin – offs, absorption or change of type of corporation it will suffice to serve timely notice to the ANH, without prejudice of the information that the Colombian authorities might require. The ANH reserves the right to evaluate the new conditions of the CONTRACTOR or of any of the companies that make it up, in terms of financial capacity, technical competence, professional capabilities and legal capacity required to perform and it can require the submission of guarantees.

Paragraph: When the assignments are made in favor of companies that control or direct the CONTRACTOR or any one of the companies that make up or direct the CONTRACTOR, or any of the companies that make it up or control the affiliates or subsidiaries thereof, or between companies that are part of the same economic group, of the ANH does not answer in the term established it shall be deemed that the relevant assignment has been authorized.

CLAUSE 26 – FORCE MAJEURE AND ACTS OF THIRD PARTIES

25.

25.1. Suspension: The performance of the obligations hereunder shall be suspended during the whole time in which any of the parties cannot comply with them in whole or in part for reasons that constitute Force Majeure or Irresistible Acts of Third Parties. When any of the parties is affected by any of such circumstances, it shall inform the other within the next fifteen (15) Calendar Days, invoking this clause and delivering the appropriate justifications, specifying the causes that generate the impediment, the manner in which the performance of the relevant obligation is affected, the estimated term of suspension of the activities and any other information allowing to evidence the occurrence of the fact and its irresistibility.

25.2. Acceptance: Within fifteen (15) calendar days after the date in which the notice is received, the non – affected Party shall answer, in writing accepting or otherwise the circumstance that releases the responsibility and such acceptance shall suspend the terms for the performance of the obligations

affected. In this case, the suspension shall occur as of the moment of occurrence of the fact invoked as releasing of responsibility. If the non affected party does not answer within that term, the cause invoked shall be considered as accepted and the performance of the affected obligation shall be suspended. The suspension only interrupts the performance of the obligations affected.

- 25.3. Cessation of the Suspension:** The party affected by the cause that releases the responsibility shall resume the performance of the suspended obligations within one Month after the disappearance of the fact invoked. In this case, it shall inform the other party within the next fifteen (15) Calendar Days. The party obligated to the performance of the obligation shall use its best efforts to comply with it in the terms and conditions agreed upon by the Parties.
- 25.4. Effects on the Terms:** Whenever the suspension prevents the compliance with any of the Exploration operations contained in any of the phases of the Minimum Exploratory Program, or of the Subsequent Exploratory Program, and shall impediment lasts for more than two (2) consecutive months, the ANH shall replace the contractual term for a term equal to that of the impediment, without prejudice that the CONTRACTOR must extend the term of the existing guaranty or establish a new one in the terms of Clause 22.

CLAUSE 27 – RESOLUTION OF CONTROVERSIES AMONG THE PARTIES

- 26. Executive Instance:** Any difference or disagreement arising because of or pursuant to the contract shall be solved by the officials of the parties authorized for such purposes. If in a term of thirty (30) calendar days after the written notice the disagreement has not been solved, the issue shall be subject to the highest executive of each one of the Parties residing in Colombia, in order to seek a joint solution. If within thirty (30) calendar days from the date in which one of the parties asked the other to bring the difference before the aforementioned executives the parties reach an agreement or decision on such issue, the agreement or decision adopted shall be signed within fifteen (15) Calendar Days from the date in which the agreement was made.
- 26.1. Expert Witnesses and Arbitration Stage:** If the top executives do not reach an agreement in the aforementioned thirty – day (30) term, or if they do not sign the agreement or decision adopted within the aforementioned fifteen (15) days, any of the parties can resort to the mechanisms of sections 27.2.1, 27.2.2 and 27.2.4, as the case may be, as follows:
- 26.1.1. Technical Expertise:** If the disagreement refers to a technical issue, it shall be submitted to the decision of experts appointed as follows: one by each Party, and a third one by the two main experts and, if there is no agreement between them and upon request of any of the parties, said third expert shall be appointed by the Association of professionals of the subject matter of the controversy or related thereto, that serves as consultant body to the National Government and with its main seat of business in Bogota.

Once the experts have been appointed:

- a) The experts shall issue their opinion in a term of thirty (30) days after their appointment. The experts shall determine the venue and term to receive information of the Parties. Upon request of the experts, the Parties can grant an extension of the original term.
- b) The parties shall furnish all the pertinent information that the experts may deem as necessary.
- c) The parties will determine and delimit the subject matters to be submitted to the experts.
- d) The costs and expenses of the experts shall be paid by the parties in equal parts.
- e) The opinion shall be produced by majority and it shall be binding for the parties with legal effects of Settlement.

26.1.2. Accounting Expertise: If the disagreement is of an accounting nature, it shall be subject to the decision of experts, who must be certified public accountants appointed as follows: one by each Party, and a third one by the two main experts and, if there is no agreement between them and upon request of any of the parties, said third expert shall be appointed by the Central Accountancy Board of Bogotá. Once the experts have been appointed, the proceedings shall be as established in subparagraphs a) to e) of the preceding subsection.

26.1.3. Controversy regarding the nature: In the event that the parties cannot agree if the difference is of a technical, accounting or legal nature, it shall be considered as a legal one.

26.1.4. Arbitration: Any disagreement or controversy derived from or related to this Contract that is not a technical or accounting disagreement, shall be solved through arbitration. The Arbitration Board shall be made up by three (3) arbitrators appointed by the parties in agreement. If the parties do not agree on the appointment of the arbitrators, they shall be appointed by the Commercial Arbitration and Conciliation Center of the Chamber of Commerce of Bogotá D. C., upon request of any of the parties. Anyway, the arbitrators must have more than five (5) years demonstrable experience in issues of the oil and gas industry. The Board must apply the substantive laws of Colombia in force, and its decision shall be in law. The language of the arbitration shall be Spanish.

26.1.5. Exclusion: Pursuant to the provisions of Clause 4 hereof (paragraph to Clause 4.3.2), the lack of agreement between the parties for the extension of the Exploitation Period of each Exploitation Area shall not lead to disagreement and it shall not be subject to the procedures set forth in this clause.

CLAUSE 28 – TERMINATION

27. Termination Clauses: This Contract shall end and cease the CONTRACTOR part, in any of the cases enunciated below:

- a) Expiration of the term of the Exploration Period, when the CONTRACTOR has not made a Discovery.

- b) Expiration of the term of the Exploitation Period. In these cases, the effects of the Contract will end respecting the Exploitation Area for which the Exploitation Period has ended.
- c) Resignation of the CONTRACTOR during the Exploration Period in the terms of Clause 4 (Section 4.12.1).
- d) Resignation of the CONTRACTOR at any time in the Exploitation Period
- e) At any time, by mutual consent of the Parties
- f) Declaration of CONTRACTOR'S Default
- g) The application of any of the Unilateral Termination cause set forth herein.
- h) The occurrence of any of the termination or forfeiture causes ordered by the Law.

In the cases of subparagraphs f), g) and h), the ANH shall enforce the guarantee subject of Clause 22, notwithstanding any remedy or action it can bring forth.

27.1. Causes of Termination for Breach of Contract: Are causes of termination for breach of contract:

- a) To assign this contract, in whole or in part, without complying with the provisions of Clause 25;
- b) To suspend, without justification, the Exploration operations for more than six (6) continuous months within one same phase.
- c) To suspend, without justification, the Assessment and 7 or Exploitation Operations for a term of more than half the term of the Assessment Program in an Area of Assessment or for six (6) uninterrupted months in an Exploitation Area. In these cases, the effects of the contract regarding the Assessment or Exploitation Area in which the suspension of operations shall end.
- d) To take undue advantage from minerals and resources not included in the scope of this Contract.
- e) To omit, in the terms established and without justification, the delivery of technical information resulting from the Exploration, Assessment, Development or Production Operations, whose importance prevents the ANH from performing its duties.
- f) Failure to comply with the delivery of the Guarantees as per the provisions of clause 22 (Section 22.3).

27.2. Procedure for the Declaration of Default: Faced with the occurrence of any of the causes of default, the ANH can end this Contract sixty (60) calendar days after making a written requirement from the Contractor, with the prior approval of the ANH'S Management Committee, indicating the cause invoked to make such representation, provided that the contractor has not filed satisfactory

explanations with the ANH within twenty (20) business days after the date of receipt of the requirement, or if it has not fixed the breach in a term of sixty (60) days. If in the aforementioned twenty (20) – business day term the CONTRACTOR gives satisfactory explanations to the ANH and the remaining term to complete the sixty (60) – calendar day term is not enough to fulfill all pending obligations, the ANH can grant an additional term to allow said performance, and it can demand all necessary guarantees to back it. If at the end of that term the corrective measures have not yet been taken, the ANH shall declare the default and the end of this Contract. It is construed that the term contemplated in this section for the performance of the obligations pending is not an extension of the term agreed for the execution of the Minimum Exploratory Program of a current phase whatsoever, and it does not amend the terms of the subsequent phases of the Exploration Period.

27.3. Causes of unilateral termination: The ANH, unilaterally, can declare the termination of this contract, at any, time, in the following cases:

- a) Because of the start of the CONTRACTOR'S liquidation proceedings, if it is a legal entity;
- b) For judicial seizure of the CONTRACTOR that seriously affects the performance of the Contract.

If the CONTRACTOR is made up by several legal entities and / or individuals, the causes in the preceding subparagraphs shall apply to the extent in which they seriously affect the performance of the Contract.

27.4. Obligatory Clauses: The ANH shall declare the termination, forfeiture or obligatory liquidation of this Contract, faced with the occurrence of the causes ordered by order of the law, such as those included in Law 418 of 1997, successively extended and amended by Laws 548 of 1999 and 782 of 2000, or in Law 40 of 1993, or in those laws that replace or amend it.

27.5. Subsequent Obligations: Once this contract ends for whatever reason and at whatever time, the Parties have the obligation to satisfactorily perform their mutual legal obligations as well as those before third parties and those contracted hereunder. This includes to assume the responsibility for resulting losses and damages when the contract has been unilaterally ended and for reasons attributable to the CONTRACTOR, including legal indemnifications and compensations.

CLAUSE 29 – ENVIRONMENT

28. The CONTRACTOR shall take special interest in the protection of the environment and the compliance with the regulations applicable in these issues. Likewise, it shall adopt and execute specific contingency plans to serve the emergencies and repair the damages in the most efficient and opportune manner.

28.1. The CONTRACTOR shall semiannually inform the ANH of the environmental aspects of the Operations it is performing, of the application of the preventive and contingency plans, and

regarding the state of the proceedings done before the competent environmental authorities in terms of permits, authorizations, concessions and licenses, as the case may be.

- 28.2.** When any Exploration Operation or activity requires environmental permits, authorizations, concessions or licenses, the Contractor shall do them until such environmental permits, authorizations, concessions or licenses are granted.
- 28.3.** The CONTRACTOR cannot start Exploitation without the approval of the environmental impact studies and the issuance of the relevant environmental licenses or other requirements. Anyway, for the phase in which exploratory wells are to be drilled, the CONTRACTOR must start the pertinent activities for the environmental licensing no later than one month after the start of the respective phase, under pain of having the contract declared as breached.
- 28.4.** The failure to comply with any of these obligations is a cause for the termination for breach of contract in the terms of Clause 28 (Section 28.2 (g)) hereof.

CLAUSE 30 – ABANDONMENT

- 29. Abandonment:** Notwithstanding the provisions of Section 4.3.4 hereof, in all cases in which the devolution of areas takes place, both inland and offshore, the CONTRACTOR shall schedule and perform all Abandonment activities in conformity to the Colombian Laws and observing the Oil Industry's Good Practices.
- 29.1. Devolution of Exploration Areas and of Assessment Areas:** No later than sixty (60) days after the date in which the Devolution of Exploration Areas or of Assessment Areas must take place, the CONTRACTOR must carry an Abandonment Program out, to the satisfaction of the ANH and of all other competent authorities.
- 29.2. In Exploitation Areas:** The Exploitation Plan of each Exploitation Area shall include the relevant Abandonment Program. Likewise, in the updating of the Exploitation Plan mentioned in Section 9.4, the CONTRACTOR shall do all adjustment to the Abandonment Program as required.
- 29.3. Abandonment Fund:**
- 29.3.1. Creation:** At the end of the first Calendar Year of the Month in which the CONTRACTOR started commercial and regular production of Hydrocarbons in any Exploitation Area and as of that moment, the CONTRACTOR shall keep in its accounts a special record called Abandonment Fund and, to guaranty the availability of the financial funds required to complete the Abandonment Program mentioned in the preceding section, the CONTRACTOR shall open a trust fund, a banking guaranty or another instrument accepted by the ANH. In either case, the terms and conditions of the instrument agreed shall be determined by the parties within the year immediately before the date in which the Abandonment Fund must be established. If no agreement is reached, the CONTRACTOR shall anyway incorporate a banking guaranty in the terms of this clause.

29.3.2. Amount of the Abandonment Fund: The amount of the abandonment fund, at the end of each Calendar Year, shall be the one resulting from the application of the following formula:

$$A_{MA} = (P_{AH} + R_{IH})^2 \times C_{AB}$$

Wherein:

A_{MA} = It is the value of the Abandonment Fund that the CONTRACTOR must record for each Exploitation Area at the end of every Calendar Year.

P_{AH} = It is the accumulated volume of hydrocarbons produced from each Exploitation Area from the beginning until the 31st of December of the year for which this calculation is made.

R_{IH} = Are the Hydrocarbons' proven reserves of each Exploitation Area expressed in Barrels of Liquid Hydrocarbons according to the Exploitation Plan and its updates. This amount includes the cumulative production (P_{AH}) plus the remaining proven reserves.

C_{AB} = It is the estimated updated cost of the Abandonment operations of each Exploitation Area. When talking of Annual Readjustments, the C_{AB} shall be reduced in the amount of the Abandonment Costs already executed.

All the aforementioned calculations of production and reserves of hydrocarbons (P_{AH} and R_{IH}) shall be made in barrels of liquid hydrocarbons, for which the Parties agree that for the purposes of making the relevant conversion, fifty seven hundred (5.700) cubic feet of gas in Standard Conditions equal one (1) Barrel of Liquid Hydrocarbons.

The variables of the formula shall be annually revised and updated by the CONTRACTOR, based on the actual disbursements of the Abandonment Activities performed and the Hydrocarbons' reserves and production volumes.

PARAGRAPH: For the purposes of this clause, it is construed as Proven Reserves the amount of Hydrocarbons that the CONTRACTOR, based on the geological and engineering analyses, estimates with a reasonable certainty that can be commercially retrieved as of a given date, based on the deposits known and according to economic conditions, operational methods and the regulatory framework prevailing at the time of calculation.

29.4. The compliance with the obligations subject of this clause does not release the CONTRACTOR from its obligation to perform, at its own cost and risk, all abandonment Operations in each Exploitation Area.

CLAUSE 31 – CONTRACTUAL DOMICILE AND APPLICABLE LAW

For all the purposes of this Contract, the parties establish as domicile the city of Bogotá, D. C., Republic of Colombia. This contract is integrally governed by the laws of Colombia and the CONTRACTOR waives any diplomatic claim in everything regarding its rights and obligations hereunder, with the exception of refusal of justice. It shall be construed that there will not be refusal of justice when the CONTRACTOR has had access to all remedies and legal means available according to the laws of Colombia.

CLAUSE 32 – SPOKESMANSHIP

Notwithstanding the legal rights of the CONTRACTOR derived from legal provisions or from the clauses of this Contract, the ANH shall be the appear on behalf of the CONTRACTOR before the Colombian authorities regarding the activities pursued by virtue of this Contract, whenever it must do so, and it shall give the officers and entities all data and reports that can be legally required. The CONTRACTOR has the obligation to prepare and supply to the ANH the relevant reports. The expenses incurred by the ANH to see to any issue as per this clause shall be on the CONTRACTOR'S charge, and, when such expenses exceed the sum of five thousand dollars of the United States of America (USD \$ 5.000) or its equivalent in Colombian currency, the prior approval of the CONTRACTOR is required. The parties represent, for any third-party relationship, that the provisions of this clause or of any other clause hereof does not imply the granting of a General Power of Attorney or that the parties have created a civil or commercial partnership or any other relationship under which any of the Parties can be considered as joint and severally liable for the acts and omissions of the other party or to have the authority or the mandate to commit the other party in any obligation. This contract relates to activities within the territory of the Republic of Colombia.

CLAUSE 33 – PAYMENTS AND CURRENCY

30.

30.1. Exchange Rate: Whenever it is required to convert Dollars of the United States of America into pesos, the representative market rate applicable shall be the one certified by the Banking Superintendence, or whichever entity that takes its place, for the date of payment.

30.2. Late Payment Interest: If the payments that the CONTRACTOR must make to the ANH pursuant to this Contract are not made in the terms established, the CONTRACTOR shall pay the ANH Late Payment Interest at the maximum legal rate allowed.

CLAUSE 34 – TAXES

The CONTRACTOR submits to the Tax Laws of Colombia.

CLAUSE 35 – NOTICES AND COMMUNICATIONS

31.

ANH: Calle 37 No. 7 – 43, 5th Floor, Guadalupe Building, Bogotá, D. C., Colombia

CONTRACTOR: Diagonal 108 No. 7 – 54, Bogotá, D. C., Colombia

31.1. Change: Any change in the person of the representative or of the domicile set forth above must be officially informed to the other party within five (5) days from the date in which it occurred.

31.2. Effectiveness: The communications between the parties related to this Contract are made upon receipt of the Party to which they were addressed, in the domiciles set forth above and in any case whenever delivered in the domicile for the legal service of notices registered with the Chamber of Commerce.

CLAUSE 36 – EXTERNAL COMMUNICATIONS

Whenever the CONTRACTOR requires to make public statements, announcements or communications regarding this Contract on data that can affect the normal development of this Contract the CONTRACTOR shall seek the prior written authorization of the ANH. Anyway, the external communications concerning Discoveries made, Discoveries declared commercial and volume of the reserves of Hydrocarbons, must be authorized by the ANH.

CLAUSE 37 – LANGUAGE

For all purposes and activities related hereto the official language of the contract is Spanish.

CLAUSE 38 – LEGALIZATION

This contract shall be legalized with the execution hereof by the Parties.

In witness hereof, it is signed at Bogotá, today, the twenty seventh (27th) day of June of year two thousand and five (2005) in two counterparts of the same text.

THE NATIONAL HYDROCARBONS AGENCY

{Signed, Illegible}

JOSE ARMANDO ZAMORA REYES

General Director

ARGOSY ENERGY INTERNATIONAL

{Signed, Illegible}

VICTOR HUGO FRANCO TAMAYO

First Alternate to the Legal Representative

Certified Translation of a document originally in Spanish 13 February 2013
No. 938 - 13 THIS SIDE VALID ONLY Page 40 of 40

The undersigned translator assumes no responsibility whatsoever for the contents or authenticity of the document(s) submitted for translation

EXHIBIT A – CONTRACTED AREA

**ATTACHMENT TO THE CONTRACT FOR THE EXPLORATION AND EXPLOITATION OF HYDROCARBONS OF THE
“CHAZA” SECTOR**

The total area comprised within the block described below is of thirty two thousand four hundred and seventy two (32.472) hectares and six thousand eight hundred and ninety three (6.893) square meters. The cartographic data was taken from the Political Map of Colombia, I. G. A. C. digital Archive, scale 1:1.500.000.

CHAZA' BLOCK

The area of the polygon formed by the vertex listed below is of thirty two thousand four hundred and seventy two (32.472) hectares and six thousand eight hundred and ninety three (6.893) square meters and it is located between the municipal jurisdictions of Mocoa and Villagarzón in the Department of Putumayo, and Piamonte, in the Department of Cauca. The area is described below and, as appears in the map included as Attachment A that is integral part of this contract, as well as the relevant charts, the point of reference taken is the geodesic vertex “MANDUR - 1325” of the Agustin Codazzi Geographical Institute, the flat GAUSS coordinates with origin Bogota – MAGNA SIRGAS datum of which are: E –764.214,78 meters, which correspond to the geographic coordinates – MAGNA SIRGAS datum: Latitude 0° 49' 23” 0.261 to the north of the Equator, Longitude 73° 11' 55” 0.175” West of Greenwich.

Point A:

From this Vertex (MANDUR - 1325) proceed in a direction N 25° 29' 2” 0.175 thousand W in a distance of 39949.54 meters until reaching point “A”, whose coordinates are N – 618590.307 meters, E – 747026,169 meters.

Point B:

From this point, proceed in a direction S 55° 10' 55” 0.671 thousand W in a distance of 20127.852 meters until reaching Point “B”, whose coordinates are N – 607097.915 meters E – 730501.783 meters. The “A – B” line is adjacent, for its entire length, with the GUAYUYACO SECTOR operated by the company ARGOSY.

Point C:

From this point, proceed in a direction N 89° 56' 54” 0.948 thousand W in a distance of 6005.233 meters until reaching Point “C”, whose coordinates are N – 607103.652 meters E – 724496.553 meters. The “B – C” line is adjacent, for its entire length, with the GUAYUYACO SECTOR operated by the company ARGOSY.

Point D:

From this point, proceed in a direction S 0° 3' 11" 0.095 thousand W in a distance of 7006.279 meters until reaching Point "D", whose coordinates are N – 600097.376 meters E – 724490.062 meters. The "C – D" line is adjacent, for its entire length, with the GUAYUYACO SECTOR operated by the company ARGOSY.

Point E:

From this point, proceed in a direction S 0° 26' 11" 0.545 thousand W in a distance of 2001.839 meters until reaching Point "E", whose coordinates are N – 598095.595 meters E – 724474.81 meters.

Point F:

From this point, proceed in a direction N 89° 56' 58" 0.423 thousand W in a distance of 6514.763 meters until reaching Point "F", whose coordinates are N – 598101.33 meters E – 717960.05 meters. The "E – F" line is adjacent, for its entire length, with the CHURUCO SECTOR operated by ECOPETROL S. A.

Point G:

From this point, proceed in a WESTERLY direction in a distance of 8454.12 meters until reaching Point "G", whose coordinates are N – 598101.33 meters E – 79505.93 meters. The "F – G" line is adjacent, for its entire length, with the CHURUCO SECTOR operated by ECOPETROL S. A.

Point H

From this point, proceed in a direction N 0° 15' 47" 0.085 thousand W in a distance of 15447.833 meters until reaching Point "H", whose coordinates are N – 613549 meters E – 709435 meters.

Point I

From this point, proceed in a direction N 89° 53' 48" 0.616 thousand E in a distance of 21105.034.833 meters until reaching Point "I" whose coordinates are N – 613587 meters E – 730540 meters.

From this point, proceed in a direction N 73° 7' 3" 0.852 thousand W in a distance of 17228.6644 meters until reaching Point "A", starting and closing point of the boundaries.

CALCULATION OF AREA, ROUTES, AND DISTANCES AS OF GAUSS COORDINATES

ORIGIN: BOGOTA

Data and Results' Table for the CHAZA Sector

Jurisdiction of the municipalities of Mocoa and Villagarzón in the Department of Putumayo, and Piamonte, in the Department of Cauca

Point	North	East	Distance	Dif. North	Dif. East	Destination
Vert	582.527,62	764.214,78				
			39.949.54	36.062.69	-17.188.61	N 25° 29' 2" 0.175 mol W
A	618.590,31	714.026,17				
			20.127.85	-11.492.39	-16.524.39	S 55° 10' 55" 0.671 thou W
B	607.097.92	730.501.78				
			6.005.23	5.74	-6.005.23	N 89° 56' 42" 0.948 thou W
C	607.103.65	724.496.55				
			7.006.28	-7.006.28	-6.49	S 0.°3211" 0.095 thou W
D	600.097.38	724.490.06				
			2.001.84	-2.001.78	-15.25	S0.°26' 11" 0.545 thou W
E	598.095.60	724.474.81				
			6.514.76	5.73	-6.514.76	N 89° 56' 58" 0.423 thou W
F	598.101.33	717.960.05				
			8.454.12	0.00	-8.451.12	WEST
G	598.101.33	709.505.93				
			15.447.83	15.447.67	-70.93	N 0°15' 47" 0.085 thou W
I	613.587.00	730.540.00				
			17.228.66	5.003.31	16.486.17	N 73° 743" 0.852 thou E
A	618.590.31	747.026.17				

EXHIBIT A

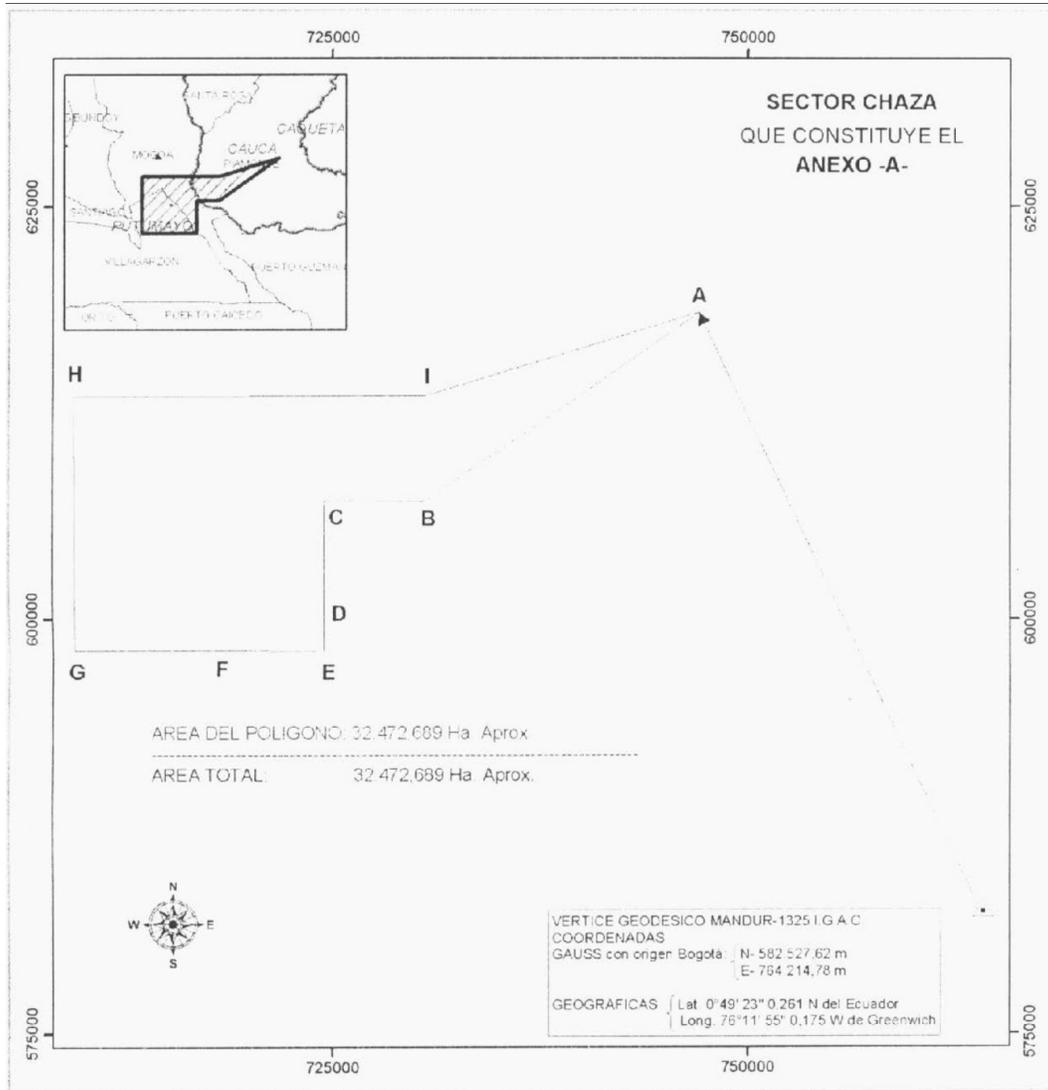


EXHIBIT B – MINIMUM EXPLORATORY PROGRAM

**ATTACHMENT TO THE CONTRACT FOR THE EXPLORATION AND EXPLOITATION OF HYDROCARBONS OF THE
“CHAZA” SECTOR**

The CONTRACTOR undertakes to carry out, as a minimum, the following Exploratory Program:

Phase 1 (12 months)

- Acquisition, processing, and interpretation of 30 kilometers of 2D seismic.
- Reprocessing and interpretation of 2D seismic available (approx 250 km.)
- Post – mortem study of wells in the area

Phases 2 and 3 (15 months each)

- Drilling of one (1) exploratory well per phase

Phases 4 and 5 (12 months each)

- Drilling of one (1) exploratory well per phase

Phase 6 (6 months)

- Drilling of one (1) exploratory well

EXHIBIT C – MODEL OF THE LETTER OF CREDIT

**ATTACHMENT TO THE CONTRACT FOR THE EXPLORATION AND EXPLOITATION OF HYDROCARBONS OF THE “XXXX”
SECTOR**

LETTER OF CREDIT NUMBER: _____

PLACE AND DATE OF ISSUE: _____

END DATE: [___ corresponds to the term of the relevant phase and three more months ___]

PAR VALUE: _____ USD \$ _____

ISSUING BANK: [___ NAME OF ISSUING BANK ___]

BENEFICIARY: National Hydrocarbons' Agency – ANH

ORDERING PARTY: [___ Name of Company ___]

NAME OF CONTRACT:

We hereby inform you that, on the account and order of [___ Name of Company ___], hereinafter the CONTRACTOR, we have issued this irrevocable standby letter of credit for the sum of money, in Colombian pesos resulting from the conversion using the representative market rate of the day in which we receive the notice of default set forth below for the sum of _____ dollars of the United States of America (USD \$ ___) to secure the performance and correct application of some or all of the obligations in Phase ___ of the Exploration Period, which has a term of ____, and all other activities inherent to such obligations emanated from the _____ CONTRACT FOR THE EXPLORATION AND EXPLOITATION XXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXX entered into by the CONTRACTOR and the ANH on the ____, hereinafter the CONTRACT.

It is understood that the liability of [___ Name of Issuing Bank ___] derived from this standby letter of credit is exclusively limited to the aforementioned sum of money in Colombian legal tender.

In the event of default by the CONTRACTOR of any or all of the obligations and other activities inherent to such obligations in its charge derived from the CONTRACT mentioned in the first paragraph of this standby letter of credit, hereinafter the SECURED OBLIGATIONS, the Beneficiary must report such default to [___ Name of Issuing Bank ___] in its offices of _____, within the term of validity of this letter of credit. In the same date in which we receive the aforementioned communication, we will proceed to unconditionally pay to the order of the Beneficiary, the sums of money claimed by him against this letter of credit, without exceeding, in any case, the total secured amount.

If the aforementioned notice of default is not sent within the term of validity hereof, our responsibility derived from this letter of credit shall cease.

The communication in which [____ **Name of Issuing Bank** ____] is informed of the default of the SECURED OBLIGATIONS shall consist of a document, duly signed by the Legal Representative of the ANH or whoever takes its place, expressing the CONTRACTOR'S default of the SECURED OBLIGATIONS and requests the payment of this letter of credit. Said communication must quote the number of this letter of credit and the sum for which it is being used. Converted into Colombian legal tender at the representative market rate of the day in which the communication is sent to us, as per certification issued by the Banking Superintendence, or whatever entity takes its place for such purposes.

This document shall be governed by the "Uniform Rules and Uses regarding Documentary Credits" (Last Revision) published by the International Chamber of Commerce (ICC).

Signature of the Legal Representative of the Issuing Bank

Certified Translation of a document originally in Spanish 13 February 2013
No. 938 - 13 THIS SIDE VALID ONLY Page 47 of 47

The undersigned translator assumes no responsibility whatsoever for the contents or authenticity of the document(s) submitted for translation

TABLE OF CONTENTS

CLAUSE 1 – DEFINITIONS	2
CLAUSE 2 - PURPOSE	6
CLAUSE 3 – CONTRACTED AREA	7
CLAUSE 4 – TERM AND PERIODS	8
CLAUSE 5 – MINIMUM EXPLORATORY PROGRAM	10
CLAUSE 6 - SUBSEQUENT EXPLORATORY PROGRAM	12
CLAUSE 7 – DISCOVERY AND ASSESSMENT	12
CLAUSE 8 – DECLARATION OF COMMERCIALITY	14
CLAUSE 9 – EXPLOITATION PLAN	15
CLAUSE 10 – EXPLOITATION WORKS PROGRAM	16
CLAUSE 11 – CONDUCTION OF THE OPERATIONS	17
CLAUSE 12 - ROYALTIES	18
CLAUSE 13 – MEASURING	19
CLAUSE 14 – AVAILABILITY OF THE PRODUCTION	19
CLAUSE 15 – NATURAL GAS	20
CLAUSE 16 – ANH'S CONTRACTUAL ECONOMIC RIGHTS	20
CLAUSE 17 – UNIFICATION	24
CLAUSE 18 – OWNERSHIP OF THE ASSETS	24
CLAUSE 19 – INFORMATION SUPPLY AND CONFIDENTIALITY	25
CLAUSE 20 – INSPECTION AND FOLLOW UP	26
CLAUSE 21 - INSURANCE	27
CLAUSE 22 - GUARANTEES	27
CLAUSE 23 – SUBCONTRACTORS, PERSONNEL AND TRANSFER OF TECHNOLOGY	28
CLAUSE 24 – OPERATOR	29
CLAUSE 25 – RIGHT OF ASSIGNMENT	30

CLAUSE 26 – FORCE MAJEURE AND ACTS OF THIRD PARTIES 31

CLAUSE 27 – RESOLUTION OF CONTROVERSIES AMONG THE PARTIES 32

CLAUSE 28 – TERMINATION 33

CLAUSE 29 – ENVIRONMENT 35

CLAUSE 30 – ABANDONMENT 36

CLAUSE 31 – CONTRACTUAL DOMICILE AND APPLICABLE LAW 37

CLAUSE 32 – SPOKESMANSHIP 37

CLAUSE 33 – PAYMENTS AND CURRENCY 38

CLAUSE 34 – TAXES 38

CLAUSE 35 – NOTICES AND COMMUNICATIONS 38

CLAUSE 36 – EXTERNAL COMMUNICATIONS 39

CLAUSE 37 – LANGUAGE 39

CLAUSE 38 – LEGALIZATION 39

EXHIBIT A – CONTRACTED AREA 40

EXHIBIT B – MINIMUM EXPLORATORY PROGRAM 44

EXHIBIT C – MODEL OF THE LETTER OF CREDIT 45

ANH

ADDENDUM NO. 1 TO THE CHAZA HYDROCARBONS' EXPLORATION AND EXPLOITATION AGREEMENT

The undersigned, to wit: on the one hand, the National Hydrocarbons' Agency, hereinafter **ANH**, a Special Administrative Unit attached to the Ministry of Mines and Energy, created by Decree – Law 1760 of 26 June 2003, with its main seat of business at Bogotá, D. C., represented herein by **JOSE ARMANDO ZAMORA REYES**, of legal age, bearer of I. D. Number 19.303.017 of Bogotá, domiciled in Bogotá, D. C., who represents that in his capacity as Director General of the ANH has the power to enter into this Agreement, and on the other **GRAN TIERRA ENERGY COLOMBIA LTD**, a Branch Office established in Colombia and the main place of business in Bogotá, D. C., according to Public Deed Number 5323 dated on the 25th of October of 1983 of Notary 7 of Bogotá, D. C., registered on the 23rd of November of the same year under Number 2092 of Book VI, with its main place of business at Bogotá, and **SOLANA PETROLEUM EXPLORATION (COLOMBIA) LIMITED**, a branch office established by public deed No. 3131 of the 29th of September of 1998 of Notary 34 of Bogotá, D. C., registered on the 26th of October of the same year under number 85.070 of Book VI, with its main place of business at Bogotá, both of them represented herein by **EDGAR LOUIS DYES**, of legal age, identified with Alien citizen's Card No. 223325, hereinafter the **CONTRACTOR**, who represents: 1. That according to the certificates of existence and incumbency, it has the power to sign this addendum; 2. under oath, that neither he nor the companies represented by him have fallen in a cause for disqualification or incompatibility or conflict of interests to enter into this document.

The ANH and the CONTRACTOR certify that they enter into this addendum after the following recitals:

1. Whereas, the ANH and the CONTRACTOR entered into the CHAZA E&E Contract on the 27th of June of 2005, agreeing the following exploration commitments:

“Phase 1 (12 months)

- *Acquisition, processing, and interpretation of 30 kilometers of 2D seismic.*
- *Reprocessing and interpretation of 2D seismic available (approx 250 km.)*
- *Post – mortem study of wells in the area*

Phases 2 and 3 (15 months each)

- *Drilling of one (1) exploratory well per phase*

Phases 4 and 5 (12 months each)

- *Drilling of one (1) exploratory well per phase*

Phase 6 (6 months)

- *Drilling of one (1) exploratory well*

2. Whereas, in letter filed under number ANH – 12 – 010368 – 2009 – E of the 26th of August of 2009, the CONTRACTOR requested from the ANH the unification of the fourth and fifth phases of the Exploration Period, stating:

“On the Mocoa River exploratory drilling area we have already applied for an environmental license and, although the issuance thereof is expected for the last quarter of 2009, provided that the Ministry does not request clarifications and does not delay the proceedings for reason beyond the control of Gran Tierra, we see that the time we have to complete the civil works and to drill the well is short.

Regarding the Moquetá exploratory drilling area, Gran Tierra has already requested the amendment of the existing environmental license in order to include the place in which Gran Tierra wishes to place the Moquetá – 1 well. Taking into account the sensitive environmental conditions of the zone, the plan is to drill it in a manner that can be transported by helicopter, making that the logistics and the preparation of the equipment takes more time than those of a drilling the equipment of which is transported over land”.

3. Whereas, having analyzed the admissibility and convenience of the amendment proposed, the Legal Advisory Office in Memorandum No. ANH – 0011 – 001636 – 2009 – I of the 8th of September of 2009 issued a favorable opinion thereof.
4. That the Director General of the ANH, pursuant to the power delegated by the Board of Directors in Agreement No. 19 of the 15th of November of 2009, issued Resolution No. 358 of the 11th of September of 2009, in which it established the terms in which it approved the amendment of the CHAZA Hydrocarbons’ Exploration and Exploitation Agreement.
5. Whereas, by virtue of the foregoing, the parties enter into this Addendum:

FIRST CLAUSE: To amend item 4.2 of Clause 4 of the Chaza Exploration and Exploitation Agreement, which shall read as follows:

*“**Exploration Period:** The Exploration Period shall last six (6) years as of the Effective Date and is divided in the phases described below. The first phase of the Exploration Period starts on the Effective Date and the subsequent phases start on the calendar day immediately after the end of the preceding phase.*

Phase 1, with a twelve – month (12) term;

Phase 2, with a fifteen – month (15) term;

Phase 3, with a fifteen – month (15) term;

Phases 4 and 5, unified, with a twenty – four – month (24) term;

Phase 6, with a six – month (6) term.

***Paragraph:** The unification of phases 4 and 5 comprises the performance of the exploratory commitments of each one of them, during the term that has been unified. The foregoing without prejudice to the contractor’s duty to comply in a full, independent and differentiated manner all the obligations inherent to those phases.”*

SECOND CLAUSE: To amend EXHIBIT B – MINIMUM EXPLORATORY PROGRAM ATTACHMENT TO THE CONTRACT FOR THE EXPLORATION AND EXPLOITATION OF HYDROCARBONS OF THE “CHAZA” SECTOR, which shall read as follows:

“The **CONTRACTOR** undertakes to carry out, as a minimum, the following Exploratory Program:

Phase 1 (12 months)

- Acquisition, processing, and interpretation of 30 kilometers of 2D seismic.
- Reprocessing and interpretation of 2D seismic available (approx 250 km.)
- Post – mortem study of wells in the area

Phases 2 and 3 (15 months each)

- Drilling of one (1) exploratory well per phase

Unified Phases 4 and 5 (24 months)

- Drilling of two (2) exploratory wells

Phase 6 (6 months)

- Drilling of one (1) exploratory well”

THIRD CLAUSE – All other provisions of the contract shall remain in full force and effect.

FOURTH CLAUSE – This addendum will be legalized with the signature of the Parties.

In witness hereof, it is signed at Bogotá, in two counterparts of the same text, on the

16 OCT. 2009

THE NATIONAL HYDROCARBONS AGENCY

{Signed, Illegible}

JOSE ARMANDO ZAMORA REYES

General Director

GRAN TIERRA ENERGY COLOMBIA LTD

and

SOLANA PETROLEUM EXPLORATION (COLOMBIA) LIMITED

{Signed, Illegible}
EDGAR LOUIS DYES
Legal Representative

SUBSIDIARIES OF GRAN TIERRA ENERGY INC.

The table below sets forth all subsidiaries of Gran Tierra Energy Inc. and the state or other jurisdiction of incorporation or organization of each.

Subsidiary	Jurisdiction of Incorporation
1203647 Alberta Inc.	Alberta, Canada
Argosy Energy LLC	Delaware
Gran Tierra Argentina Holdings ULC	Alberta, Canada
Gran Tierra Brazco ULC	Alberta, Canada
Gran Tierra Callco ULC	Alberta, Canada
Gran Tierra Energy Argentina S.R.L.	Argentina
Gran Tierra Energy Brasil Ltda.	Brazil
Gran Tierra Energy Canada ULC	Alberta, Canada
Gran Tierra Energy Cayman Islands Inc.	Cayman Islands
Gran Tierra Energy Colombia, Ltd.	Utah (a limited partnership)
Gran Tierra Energy Inc.	Alberta, Canada
Gran Tierra Energy International (Peru) Holdings B.V.	Curacao
Gran Tierra Energy International Holdings Ltd	Cayman Islands
Gran Tierra Energy Peru S.R.L.	Peru
Gran Tierra Energy Peru B.V.	Curacao
Gran Tierra Exchangeco Inc.	Alberta, Canada
Gran Tierra Finance (Luxembourg) Sarl	Luxembourg
Gran Tierra Goldstrike Inc.	Alberta, Canada
Gran Tierra Petroco Inc.	Canada
P.E.T.J.A. S.A.	Argentina
PCESA	Ecuador
Petrolifera Petroleum (Americas) Limited	Barbados
Petrolifera Petroleum (Colombia) Limited	Cayman Islands
Petrolifera Petroleum (Holdings) Limited	Barbados
Petrolifera Petroleum (Peru) Limited	Barbados
Petrolifera Petroleum (US) Limited	Delaware
Petrolifera Petroleum Del Peru S.A.C.	Peru
Petrolifera Petroleum Limited	Canada
Solana Resources Limited	Alberta, Canada

Consent of Independent Registered Chartered Accountants

We consent to the incorporation by reference in Registration Statements No. 333-146815, 333-156994, 333-171122 and 333-183029, on Form S-8, and in Registration Statements No. 333-140171, 333-153376 and 333-156993, on Form S-3, of our reports dated February 26, 2013, relating to the consolidated financial statements of Gran Tierra Energy Inc. and the effectiveness of Gran Tierra Energy Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Gran Tierra Energy Inc. for the year ended December 31, 2012.

/s/ Deloitte LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 26, 2013

Consent of Independent Reserve Engineers

Mr. James Rozon
Chief Financial Officer
Gran Tierra Energy Inc. ("Gran Tierra")
300, 625 - 11th Avenue S.W.
Calgary, Alberta T2R 0E1
Canada

**Re: Gran Tierra Registration Statement:
Form S-8 (Reg. Nos. 333-146815, 333-156994, 333-171122 and 333-183029)
Form S-3 (Reg. Nos. 333-140171, 333-153376 and 333-156993)
Filed with the United States Securities Exchange Commission**

Dear Mr. Rozon:

As the independent reserve engineers for Gran Tierra, GLJ Petroleum Consultants Ltd. ("GLJ"), hereby confirms that it has granted and not withdrawn its consent to the filing of GLJ's reserve report and to the reference to GLJ's evaluation of Gran Tierra's reserves as of December 31, 2012 in the form and context disclosed by Gran Tierra in its Form 10-K submission to be filed with the United States Securities and Exchange Commission on approximately February 26, 2013 for the period ending December 31, 2012, and to the incorporation by reference thereof in the registration statements listed above.

Please do not hesitate to contact us if you have any questions.

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Leonard L. Herchen

Leonard L. Herchen, P. Eng.

Vice-President

Dated: February 26, 2013

Calgary, Alberta

CANADA

CERTIFICATION

I, Dana Coffield, certify that:

1. I have reviewed this Form 10-K of Gran Tierra Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2013

/s/ Dana Coffield

Dana Coffield

Chief Executive Officer and President

(Principal Executive Officer)

CERTIFICATION

I, James Rozon, certify that:

1. I have reviewed this Form 10-K of Gran Tierra Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2013

/s/ James Rozon

James Rozon
Chief Financial Officer
(Principal Financial Officer)

Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of

Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to the requirement set forth in Rule 13a-14(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") and Section 1350, Chapter 63 of Title 18 of the United States Code (18 U.S.C.-§1350), each of Dana Coffield, Chief Executive Officer and President of Gran Tierra Energy Inc., a Nevada corporation (the "Company"), and James Rozon, Chief Financial Officer of the Company, does hereby certify, to such officer's knowledge that:

The Annual Report on Form 10-K for the fiscal year ended December 31, 2012 (the "Form 10-K") to which this Certification is attached as Exhibit 32.1 fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act. The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned have set their hands hereto as of the 26th day of February 2013.

/s/ Dana Coffield

Dana Coffield
Chief Executive Officer and President

/s/ James Rozon

James Rozon
Chief Financial Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not deemed filed with the Securities and Exchange Commission as part of the Form 10-K or as a separate disclosure document and is not to be incorporated by reference into any filing of the Company under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended (whether made before or after the date of the Form 10-K), irrespective of any general incorporation language contained in such filing.

THIRD PARTY REPORT ON RESERVES

By GLJ Petroleum Consultants Ltd. - (Independent Qualified Reserves Evaluator)

This report is provided to satisfy the requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K.

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

- i. We have prepared an independent evaluation of the oil and gas reserves of Gran Tierra Energy Inc. (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company's year-end reserves reporting requirements under US Securities Regulation S-K and for other internal business and financial needs of the Company.
 - ii. We have evaluated the reserves of the Company as at December 31, 2012. The completion date of our report is January 28, 2013 for the properties in Argentina, Brazil and Colombia.
 - iii. The following table sets forth the geographic area covered by our reports, proved, probable and possible reserves estimated using constant prices and costs, and the proportion of the Company's total reserves that we have evaluated.
-

Company Net Reserves

Category	Crude Oil Mbbbl	Natural Gas MMcf	Natural Gas Liquids Mbbbl	Oil Equivalent Mbbbl (1)	Portion of Reserves Evaluated, %
Proved					
Developed					
Argentina	2,387	2,777	72	2,922	100
Brazil	347	—	—	347	100
Colombia	24,646	8,551	31	26,102	100
Undeveloped					
Argentina	3,304	527	31	3,423	100
Brazil	1,244	—	—	1,244	100
Colombia	6,432	921	—	6,586	100
Total proved	38,360	12,776	134	40,624	100
Probable					
Developed					
Argentina	697	298	19	766	100
Brazil	397	—	—	397	100
Colombia	5,670	783	3	5,804	100
Undeveloped					
Argentina	1,787	1,538	27	2,070	100
Brazil	942	—	—	942	100
Colombia	5,242	2,517	0	5,662	100
Total probable	14,735	5,136	49	15,641	100
Possible					
Developed					
Argentina	1,425	695	22	1,563	100
Brazil	686	—	—	686	100
Colombia	4,732	1,902	7	5,056	100
Undeveloped					
Argentina	4,344	46,733	428	12,561	100
Brazil	1,384	—	—	1,384	100
Colombia	8,428	2,337	0	8,818	100
Total possible	20,999	51,667	457	30,068	100

(1) Oil equivalence factors: Crude Oil 1 bbl/bbl, Natural Gas 6 Mcf/bbl, NGL 1 bbl/bbl.

Our report covers 100% of the Company's total oil, natural gas and natural gas liquid reserves.

- iv. As noted in item iii., our evaluation covered 100% of the Company's proved, probable and possible reserves. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements under the U.S. Securities and Exchange Commission ("SEC requirements").

Data used in our evaluation were obtained from regulatory agencies, public sources and from Company personnel and Company files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, recent production, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts and capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were satisfactorily resolved.

The Company has warranted in a representation letter to us that, to the best of the Company's knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

A field examination of the evaluated properties was not performed nor was it considered necessary for the purposes of our report.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under Regulation S-K.

- v. As required under SEC Regulation S-K, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the effective date of our report unless prices are defined by contractual or other regulator arrangements. In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

Benchmark Average Prices and average realized prices for the year ended December 31, 2012 are as follows:

<u>Twelve Month Average Benchmark Prices</u>		
Brent Blend Crude Oil FOB North Sea (\$US/bbl)	\$	111.46
Average realized prices		
Oil and NGL's per bbl - Colombia	\$	103.04
Natural Gas (\$/Mcf) - Colombia	\$	3.16
Light/Medium Oil (\$/bbl) - Argentina	\$	71.34
Natural Gas (\$/Mcf) - Argentina	\$	3.83
Condensate (Natural Gasoline) (\$/bbl) - Argentina	\$	78.48
Natural Gas Liquids (\$/bbl) - Argentina	\$	61.73
Light/Medium Oil (\$/bbl) - Brazil	\$	97.35

- vi. Our report has been prepared assuming the continuation existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce , there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company's ability to recovery the estimated reserves.
- vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, petroleum engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, contractual, statutory and regulatory provisions.
- viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all **appropriate data, assumptions, methods and procedures applicable for** the filing of reserves information under U.S. SEC Regulation S-K. All methods and procedures considered necessary under the circumstances to prepare the report were used.
- ix. A summary of the Company reserves evaluated by us is provided in item iii.

GLJ Petroleum Consultants Ltd.
 4100, 400 - 3rd Avenue S.W.
 Calgary, Alberta, Canada T2P 4H2
 Dated: February 16, 2013

/s/ Leonard L. Herchen

Leonard L. Herchen, P. Eng.

Vice President

