GRAN TIERRA ENERGY INC.
Form 10-K
February 26, 2013

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

ý	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

o	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	98-0479924
(State or other jurisdiction of incorporation or organization)	(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 ý No o
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 o No ý
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 ý No o

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 ý No o
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. ý

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 x	Accelerated filer o
Non-accelerated filer o (do not check if a smaller reporting company)	Smaller reporting company o

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

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

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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 exp 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.

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- 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.

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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.

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- 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 Miraflor 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, Miraflor 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 CEPSAC, 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) (Mbbl)	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.

	Proved Reserves		Probable Reserves		Possible Reserves	
Price Case	Liquids (Mbbl)(1)	Natural Gas (MMcf)	Liquids (Mbbl)	Natural Gas (MMcf)	Liquids (Mbbl)(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	—
	38,579	13,009	14,400	5,146	21,368	51,375
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	—

38,344	12,747	15,042	5,183	21,903	51,682

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(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	