GRAN TIERRA ENERGY INC.
Form 10-K
March 02, 2015

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, 2014

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.)

200, 150 13 Avenue S.W.
Calgary, Alberta, Canada T2R 0V2
(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 $2.2 billion (including shares issuable upon exercise of exchangeable shares). Aggregate market value excludes an aggregate of 1,080,214 shares of Common Stock and 7,404,427 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 24, 2015, the following numbers of shares of the registrant's capital stock were outstanding: 276,108,951 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 4,524,627 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 5,558,518 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 2015 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2014.

Gran Tierra Energy Inc.

Annual Report on Form 10-K

Year Ended December 31, 2014

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CAUTIONARY LANGUAGE 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		

Production represents production volumes NAR adjusted for inventory changes and losses. Our oil and gas reserves are also reported NAR.

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. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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. As noted above, production volumes are also reported net of inventory adjustments and losses. 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. For these reasons, 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.

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- 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 the rights to oil and gas properties in Colombia, Peru and Brazil.

Our principal executive offices are located at 200, 150-13th Avenue S.W., Calgary, Alberta, Canada. The telephone number at our principal executive offices 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.

On June 25, 2014, we, through several of our indirect subsidiaries, sold our Argentina business unit to Madalena Energy Inc. ("Madalena") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares.

Largely as a result of the current low commodity price environment, we reevaluated our business strategy with a renewed focus on balancing the return and risk of our exploration and development projects. As a result, on February 19, 2015, we made the decision to cease all further development expenditures on the Bretaña field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. The high capital investment, associated debt financing and long-term payout horizon of this project does not align with our shift in strategy as announced on February 2, 2015.

Considering the current low commodity price environment and the significant aspects of the Bretaña field project which were no longer in line with our strategy, our Board of Directors determined that they would not proceed with the further capital investment required to develop the Bretaña field. As a result of this decision, all probable and possible reserves associated with the field were reclassified as contingent resources in a report with an effective date of January 31, 2015. Further as a result, $265.1 million of unproved properties relating to Block 95 were impaired at December 31, 2014. We expect to continue to identify and evaluate all options for the Bretaña field.

In 2014:

- in Colombia, we continued to focus on developing our producing conventional light oil fields, including Costayaco and Moqueta, and on the generation of exploration prospects;

- in Peru, we continued engineering, procurement and construction work in preparation for a long-term production test, commenced drilling the Bretaña Sur 95-3-4-1X well, drilled the Bretaña Sur 95-2-1XD water disposal well and continued to purchase long-lead items for future drilling activities on the Bretaña field on Block 95. Subsequent to year-end, the Bretaña Sur appraisal well completed drilling operations and encountered an oil column less than what we had estimated prior to drilling. On Block 107, we commenced the acquisition of 2-D seismic and continued the refurbishment of a base camp; and

- in Brazil, on Block REC-T-155 we successfully completed the dual completions of the 3-GTE-03-BA and 4-GTE-04-BA development wells in the Tiê field and completed a single stage fracture stimulation on the 1-GTE-8DP-BA exploration well, commenced the acquisition of 3-D seismic on Blocks REC-T-86, REC-T-117 and REC-T-118, and performed planning activities for future drilling activity.

In the year ended December 31, 2014, we incurred capital expenditures of $416.2 million (excluding changes in non-cash working capital). In 2014, capital expenditures included drilling expenditures of $245.3 million, geological and geophysical ("G&G") expenditures of $96.1 million, facilities expenditures of $36.6 million and other expenditures of $38.3 million.

Our acreage as of December 31, 2014, including acquisitions and excluding acres where relinquishments and acreage changes were subject to various government approvals, included:

- 3.4 million gross acres (2.8 million net) in Colombia covering 16 exploration and production contracts, five of which were producing and 15 of which were operated by Gran Tierra (excludes 0.9 million gross and net acres on four blocks where relinquishments were subject to approval and acreage changes, also subject to approval, on a further two blocks and includes 126,792 gross and 88,754 net acres on a block where the acquisition was subject to approval);

- 47,734 gross acres (47,734 net) in Brazil covering seven exploration blocks, one of which was producing and all of which were operated by Gran Tierra; and

- 5.7 million gross acres (5.7 million net) in Peru covering five exploration licenses, none of which were producing and all of which were operated by Gran Tierra.

Oil and Gas Properties – Colombia

We have interests in 19 blocks in Colombia and are the operator in 17 blocks. The Chaza, Guayuyaco, Garibay, Llanos-22 and Santana Blocks have producing oil wells. During the year ended December 31, 2014, 83% of our consolidated production, NAR adjusted for inventory changes and losses, was from the Chaza Block. During 2014, we relinquished our interest in the Rumiyaco and Rio Magdalena Blocks. Relinquishments on four other blocks are pending final documentation to become effective. During 2014, we signed a farm-in agreement for the Putumayo-4 Block; however, this farm-in is subject to completion of due diligence associated with the Putumayo-4 Exploration and Production Contract to our satisfaction and Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") approval. We also assigned our working interest in the Turpial Block to a third party.

Royalties

Colombian royalties are regulated under laws 756 of 2002 and 1530 of 2012. All discoveries made subsequent to the enactment of law 756 of 2002 have the sliding scale royalty described below. Discoveries made before the enactment of this law have a royalty of 20%. The ANH contracts to which we are 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%. In addition to the sliding scale royalty, the Llanos-22, Sinu-1 and Sinu-3 Blocks have additional x-factor royalties of 1%, 3% and 17%, respectively.

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%.

Pursuant to the Chaza Block exploration and production contract (the "Chaza Contract") between the ANH and Gran Tierra, our production from the Costayaco Exploitation Area is also subject to an additional royalty (the "HPR royalty") that applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. Pursuant to the Chaza Contract, any new Exploitation Area on the Chaza Block will also be subject to the HPR royalty once the production on such Exploitation Area exceeds five MMbbl of cumulative production. The Moqueta Exploitation Area in the Chaza Block and the Jilguero Exploitation Area in the Garibay Block will each be subject to the HPR royalty once production from each Exploitation Areas has reached five MMbbl.

There is a dispute with the ANH as to whether the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area or only after production from the Moqueta Exploitation Area has reached five MMbbl (see Item 3. “Legal Proceedings” and Item 8. "Financial Statements and Supplementary Data", below). As at December 31, 2014, total cumulative production from the Moqueta Exploitation Area was 4.2 MMbbl. The estimated HPR royalty that would be payable on cumulative production to that date if the ANH’s interpretation is successful is $64.1 million.

For exploration and production contracts awarded in the 2010, 2012 and 2014 Colombia Bid Rounds, the HPR 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 criterion for the HPR 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 Block has the sliding scale royalty but does not have the additional royalty.

In addition to these government royalties, our original interests in the Santana, Guayuyaco, Chaza and Azar Blocks acquired on our entry into Colombia in 2006 are subject to a third party royalty. The additional interests in Guayuyaco and Chaza that we acquired on the acquisition of Solana in 2008 are not subject to this third party royalty. On June 20, 2006, we 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 apply to our original interests in production from the Santana, Guayuyaco, Chaza and Azar Blocks. The overriding royalty rights start 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 ("NPI"). This NPI 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 an NPI. In addition, there are conditional overriding royalty rights that apply only to the pre-existing fields. Currently, we are subject to a 10% NPI on 50% of our working interest production from the Costayaco and Moqueta fields in the Chaza Block and 35% of our working interest production from the Juanambu field in the Guayuyaco Block, and overriding royalties on our working interest production from the Santana Block and the Guayuyaco field in the Guayuyaco Block.

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 exploitation 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. The discovery of the Moqueta exploitation field in the Chaza Block was the result of drilling the Moqueta-1 exploration well in the second quarter of 2010. We are in the second additional exploration program which will end on June 26, 2015. The second additional exploration program requires one exploration well to be drilled by June 26, 2015, which we plan to drill in the first half of 2015. The additional exploration program requires that 50% of this block's acreage, excluding exploitation and evaluation areas, be relinquished; however, we have not yet received final documentation from the ANH for this acreage change. This block includes 34 productive wells in two independent exploitation fields - Costayaco and Moqueta. The production phase for the Costayaco exploitation field will end in 2033 and for the Moqueta exploitation field will end in 2037. After the expiration of the production phase, we must carry out an abandonment program to the satisfaction of the ANH. In conjunction with the abandonment, we have established and must maintain an abandonment fund to ensure that financial resources are available at the end of the contract.

In 2014, we drilled and completed the Costayaco-20, Costayaco-21 and Costayaco-22 development wells in the Costayaco field and commenced drilling the Costayaco-19i development well. Additionally, we drilled the Moqueta-13, Moqueta-15, Moqueta-16 and Moqueta-17 development wells in the Moqueta field. The Costayaco-20, Costayaco-21, Costayaco-22, Moqueta-13 and Moqueta-15 development wells were completed as oil producing wells. The Moqueta-16 development well was on test production in mid-December 2014 and was pending stimulation and testing at year-end. We also commenced drilling the Eslabón Sur Deep-1 exploration well. This well is currently suspended pending the further evaluation of pay zones. Drilling of the Corunta-1 exploration well continued into 2014, but we encountered drilling problems prior to reaching the reservoir target on this long-reach deviated well and the decision was made to abandon the well. We continued drilling the Zapotero-1 exploration well, a long-reach deviated well, but production testing of this well indicated the presence of water in the Villeta T and U Sandstones and in the Caballos formation. We commenced drilling the Moqueta-14 development well in the Moqueta field, but drilling of this well was suspended. We also continued work to obtain the necessary environmental and social permits for future seismic programs and performed facilities work on this block.

In 2015, we plan to complete the Moqueta-17 development well and drill at least one additional well on this block. We also plan to perform additional facilities work on this block.

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.

This block includes six gross productive wells in two fields - Guayuyaco and Juanambu. The Guayuyaco field was discovered in 2005. The production phase of the contract will end in 2030, following which, the property will be returned to Ecopetrol upon expiration of the production contract and we are not obligated to perform remediation work.

In 2014, we completed initial testing and evaluation of the Miraflor Oeste exploration well. This oil well is currently on long-term test production. In 2015, no significant capital expenditures are planned on this Block.

Garibay Block

Solana acquired the Garibay Block in October 2005. The block covers 38,919 gross acres in the Llanos Basin and we have a non-operated 50% working interest. Compania Espanola de Petroleos Colombia, S.A.U. (“CEPCOLSA”), a wholly-owned subsidiary of Compañia Española de Petróleos S.A., has the remaining interest and is the operator. This block includes three gross productive wells in the Jilguero field. The block is held under an Exploration and Exploitation Contract with the ANH. We applied for and were granted a second additional exploratory program which extended the exploration phase of the contract to October 24, 2015. There is an obligation to drill one exploration well in this exploration phase. The first and second additional exploration programs each required that 50% of this block's acreage, excluding exploitation and evaluation areas, be relinquished. During 2014, we relinquished acreage in accordance with the first additional exploration program; however, we have not yet received final documentation from the ANH for the acreage change relating to the second additional exploration program. The production phase for the Jilguero field will end in 2037. In 2014, health, safety and environment ("HSE") costs were incurred on this block. In 2015, together with our partner, we are considering drilling one gross well and plan to perform additional facilities work on this block.

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 CEPCOLSA (CEPCOLSA retained a 55% working interest and operatorship). CEPCOLSA farmed-in for a 30% working interest on the Putumayo Piedemonte Norte Block. The Llanos-22 Block is held under an Exploration and Exploitation Contract with the ANH and covers 42,388 gross acres. This block has two gross oil productive wells in the

Ramiriqui field. We are in a unified first and second additional exploration program which will end on February 3, 2017. This exploration period requires one exploration well to be drilled and the acquisition of 125 square kilometers of 3-D seismic. On December 4, 2014, we declared commerciality for the Ramiriqui field. The exploitation phase on this field will end in December 2038.

In 2014, we continued seismic reprocessing and G&G studies and performed facilities work. In 2015, no significant capital expenditures are planned on this block.

Santana Block

The Santana Block contract was signed in July 1987 and covers 1,119 gross acres in the Putumayo Basin and includes nine gross productive 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 July 2015, at which time the property, including facilities and pipelines, will be returned to Ecopetrol, but we will not be obligated to perform remediation work.

In 2014, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2015.

Putumayo 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 Putumayo 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 CEPCOLSA, but retained operatorship. This asset swap was in connection with the Llanos-22 Block farm-in agreement. The first exploration phase, which is currently under suspension, requires the acquisition, processing and interpretation of 70 kilometers of 2-D seismic. We have already acquired 18 kilometers of 2-D seismic on this block. The exploitation phase would end 24 years after commerciality, if a discovery is made and its development is approved.

In 2014, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2015.

Putumayo Piedemonte Sur Block

The Putumayo 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 Putumayo 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 unified phase required the acquisition of 55 kilometers of 2-D seismic and one exploration well to be drilled by July 24, 2014; however, we applied for and were granted a suspension of this phase for the period until an environmental license is granted. The exploration phase will end in February 2017 and the exploitation phase would end 24 years after commerciality, if a discovery is made and its development is approved.

In 2014, we acquired 2-D seismic and completed interpretation of the seismic data on this block. In 2015, no significant capital expenditures are planned for this block.

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 required the acquisition of 200 kilometers of 2-D seismic and the drilling of one stratigraphic well by December 15, 2014; however, we applied for and were granted an extension of this phase to May 28, 2016. We have requested a further extension. After the end of the current exploration phase, we may convert this TEA contract into an Exploration and Exploitation Contract.

In 2014, there were no significant capital expenditures on this block. In 2015, no significant capital expenditures are planned for this Block.

Cauca-7 Block

We were awarded the Cauca-7 Block in the 2010 Colombia Bid Round. The block covers 785,451 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 required the acquisition of 250 kilometers of 2-D seismic and the drilling of one stratigraphic well by December 15, 2014; however, we applied for and were granted an extension of this phase to January 31, 2016. We plan to apply for a further extension of the phase. After the end of the current exploration phase, we may convert this TEA contract into an Exploration and Exploitation Contract.

In 2014, we acquired 44 kilometers of 2-D seismic on this block. In 2015, we plan to acquire a further 51 kilometers of 2-D seismic on this block.

Putumayo-10 Block

We were awarded the Putumayo-10 Block in the 2010 Colombia Bid Round. The block covers 114,097 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 required the acquisition of 73 kilometers of 2-D seismic and two exploration wells to be drilled by September 15, 2014; however, we requested and were granted suspensions of this phase to December 13, 2014 due to community and permitting issues. We have requested a further suspension of this phase. We have 20 months from the date the suspension was lifted to complete the work obligation. The exploration phase would end in December 2018, but this period would be extended in the event of phase suspensions, and the exploitation phase would end 24 years after commerciality, if a discovery is made and its development is approved.

In 2014, we commenced activities in preparation for the acquisition of 2-D seismic on this block. In 2015, we may acquire 74 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 March 3, 2014; however, we requested and were granted suspensions to December 11, 2014. We have requested a further suspension of this phase due to community issues. The ANH has also granted a restitution period of 82 days from December 11, 2014. We have requested a further extension of this restitution period. The exploration phase would end in October 2017, but this period will be extended to reflect phase suspensions, and the exploitation phase would end 24 years after commerciality, if a discovery is made and its development is approved.

In 2014, we completed 3-D seismic on this block and, in 2015, we plan to continue community consultations this block; however, activities on this block are currently suspended pending the receipt of a community certification.

Catguas Block

Solana acquired the Catguas Block in November 2005. We are the operator of the block which covers 330,355 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. We are in a unified phase two and three of five exploration periods in the contract. This phase was to end in May 2007; however, the block contract is under suspension by ANH as a result of force majeure. This phase requires three exploratory wells to be drilled, or two exploratory wells and re-entry of an existing well, the acquisition of 80 kilometers of 2-D seismic and the relinquishment of 15% of the block. We have satisfied the work obligation for 80 kilometers of 2-D seismic. We may elect to enter into up to two subsequent exploration periods of 12 months each in length, which both require the drilling of one exploration well and the relinquishment of 15% of the acreage at the end of each phase. The exploitation phase would end 24 years after commerciality, if a discovery is made and its development is approved.

In 2014, we incurred environmental remediation costs on this block. No significant capital expenditures are planned for 2015.

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 a TEA Contract with the ANH. The contract comprises one exploration phase which requires the completion of regional studies, the acquisition of 478 kilometers of 2D seismic and one stratigraphic well to be drilled by August 12, 2017.

In 2014, we continued G&G studies, including aeromagnetic surveys and completed the acquisition of 491 kilometers of 2-D seismic which satisfied our work obligation on this block. In 2015, we plan to continue G&G studies on this block.

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 first exploration phase which will end on September 11, 2016, and requires the completion of regional studies, the
acquisition of 488 kilometers of 2-D seismic and one exploration well to be drilled.

In 2014, we continued G&G studies, including aeromagnetic surveys and completed the acquisition of 332 kilometers of 2-D seismic on this block. In 2015, we plan to continue G&G studies and may acquire 45 kilometers of 2-D seismic on this block.

Putumayo-31 Block

We were awarded the Putumayo-31 Block in 2014 Colombia Bid Round. The block covers 34,826 gross acres in the Putumayo Basin. We are the operator of the block with a 65% working interest. The block is held under an Exploration and Exploitation Contract with the ANH. We are in phase zero, the community consultation phase, of the contract which will end on September 2, 2015.

In 2014, there were no significant capital expenditures on this block. In 2015, we plan to continue work to obtain the necessary environmental and social permits for future drilling programs.

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 have applied to the ANH to relinquish our interest in this block. This relinquishment is subject to receipt of final documentation from ANH. We are obligated to perform remediation work on this block and we have included the estimated costs of this work in our annual financial statements.

In 2014, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2015.

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 have applied to Ecopetrol to relinquish our interest in this block. This relinquishment is subject to receipt of final documentation from Ecopetrol. We are obligated to perform remediation work on this block and we have included the estimated costs of this work in our annual financial statements.

In 2014, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2015.

Azar Block

We have a 100% working interest in the Azar Block. This block covers 47,224 gross acres in the Putumayo Basin and we are the operator. We have applied to the ANH to relinquish our interest in this block. This relinquishment is subject to receipt of final documentation from ANH. We are obligated to perform remediation work on this block and we have included the estimated costs of this work in our annual financial statements.

In 2014, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2015.

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 have submitted documentation to the ANH to relinquish our interest in this block. This relinquishment is subject to receipt of final documentation from the ANH. We are obligated to perform remediation work on this block and we have included the estimated costs of this work in our annual financial statements.

In 2014, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2015.

Putumayo-4 Block

In the fourth quarter of 2014, we signed a farm-out agreement pursuant to which we would acquire a 70% operated working interest in the Putumayo-4 Block. This acquisition is subject to completion of due diligence associated with the Putumayo-4 Exploration and Production Contract to our satisfaction and ANH approval. The block covers 126,792 gross acres in the Putumayo Basin. The block is held under an Exploration and Production Contract with the ANH.

Oil and Gas Properties - Brazil

We have interests in seven blocks in Brazil and are the operator in all of these blocks. Our Brazilian properties are located in the Recôncavo Basin in Eastern Brazil in the State of Bahia. Block 155 in the Recôncavo Basin has three producing oil wells.

All of our blocks in Brazil are subject to an 11% royalty, which consists of a 10% crown royalty and a 1% landowner 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 27,076 gross acres. We are the operator of these blocks with a 100% working interest. In September 2012, we received declaration of commerciality for the Tiê field on Block REC-T-155. This field includes three productive wells. In August 2014, the ANH approved our application for extensions of the exploration phases on Blocks REC-T-129, REC-T-142 and REC-T-155. We are in the First Appraisal Plan ("PAD") phase for these blocks which will end May 24, 2015. This phase requires G&G studies and analysis. The exploration phase of the concession agreement on Block REC-T-224 was due to expire on December 11, 2013; however, under the concession agreement we were able to and did submit an application to the ANP for a suspension of the exploration phase of this block. A suspension of the exploration phase of this block was granted and the exploration phase on Block REC-T-224 will end one year after the date an environmental permit is granted. This phase required one exploration well to be drilled by December 11, 2013.

In December 2014, the ANP issued an injunction specifically related to properties in the Recôncavo Basin covered by Bid Round 12. This injunction placed a moratorium on unconventional activities on the Bid Round 12 blocks, all of which were unconventional exploration targets, until such a time as policies governing unconventional activities are finalized. Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 were granted in Bid Round 9, for which there has not been a similar injunction; however, we expect that the ANP's injunction may limit our ability to receive permits in the short-term for our blocks with unconventional exploration targets.

In 2014 on Block REC-T-155, we successfully completed the dual completions of the 3-GTE-03-BA and 4-GTE-04-BA development wells in the Tiê field, completed a single stage fracture stimulation on the 1-GTE-8DP-BA exploration well, continued to evaluate alternatives for the 1-GTE-07HPC-BA exploration well and performed planning activities for future drilling activity. In 2015, we plan to perform additional facilities work in the Tiê field and perform a workover on one of our producing wells.

Blocks REC-T-86, REC-T-117 and REC-T-118

We were awarded Blocks REC-T-86, REC-T-117 and REC-T-118 in the 2013 Brazil Bid Round 11. These blocks are located north of our other blocks in the Recôncavo Basin and cover 20,658 gross acres. We are the operator with a 100% working interest. Concession Agreements were executed on August 30, 2013. All three blocks are in the first exploration phase which will end in August 2016. This phase requires the acquisition of a total of 120 square kilometers of 3-D seismic on the three blocks and two exploration wells to be drilled on Block REC-T-117 and three exploration wells on Block REC-T-118.

In 2014, we commenced the acquisition of 120 square kilometers of 3-D seismic on these three blocks. In 2015, we plan to complete the acquisition of 3-D seismic and perform work to prepare for future drilling on these three blocks.

Oil and Gas Properties - Peru

We have interests in five blocks in Peru and we are the operator in each of the blocks. 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 in which we have an interest. Block 133 has an additional royalty 'X' factor of 15%.

Block 95

In December 2010, we acquired a 60% working interest in Block 95. During the first quarter of 2013, we acquired the remaining 40% working interest. We are the operator of this block. In 2013, we drilled the Bretaña Norte 95-2-1XD exploration well which resulted in an oil discovery. Block 95 has an area of 853,210 gross acres. In 2014, we relinquished 1.47% of the block's acreage in accordance with the requirements of the fourth exploration phase. We have relinquished a total of 33% of the block's acreage. We are in the fifth exploration period of six which requires the completion of 200 units of work by June 27, 2015. The exploration period is currently due to end on December 27, 2015, and the exploitation period on December 27, 2038.

In 2014, we drilled the Bretaña Sur 95-3-4-1X appraisal well on the L4 lobe on the Bretaña field, which satisfied our work obligation for the fifth exploration period. Subsequent to year-end, the Bretaña Sur appraisal well completed drilling operations and encountered approximately six feet of oil pay above the oil-water contact in the Vivian Sandstone Reservoir. This oil column is less than what we had estimated prior to drilling. We also drilled the Bretaña-1WD water disposal well, completed engineering and procurement and construction work in preparation for long-term production test and continued to purchase long-lead items for future drilling activities on this field.

As previously discussed, in February 2015, we ceased all further development expenditures on the Bretaña field other than what is necessary to maintain tangible asset integrity and security. We plan to continue to identify and evaluate all options for the Bretaña field.

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 and assumed operatorship in January 2013. Blocks 123 and 129 have a total area of 3,491,240 gross acres. We are in the third exploration period 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 29, 2013. However, this block has been under force majeure since April 29, 2013, to allow us time to assume operatorship. The current period requires one exploration well to be drilled or 300 units of work. This obligation was satisfied by acquisition of 318 kilometers of 2-D seismic prior to assuming operatorship. On Block 129, the third exploration period 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. However, this block has been under force majeure since July 17, 2013, to allow us time to assume operatorship. This period required one exploration well to be drilled or 204 units of work. This obligation was satisfied by the acquisition of 252 kilometers of 2-D seismic by our former partners on this block.

In 2014, we continued work to obtain the necessary environmental and social permits for future drilling programs. In 2015, we plan to continue the permitting process.

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 period, which requires one exploration well to be drilled or 300 units of work by July 10, 2015, but we applied for and were granted approval to change the work obligation to the acquisition, processing and interpretation of 300 kilometers of 2-D seismic. We have applied for an extension of the exploration period. The block was under force majeure from May 25, 2012 to August 20, 2013, and from September 25, 2013, to August 15, 2014, due to delays in the permitting process.

In 2014, we commenced the acquisition of 2-D seismic and continued the refurbishment of a base camp. In 2015, we plan to continue the refurbishment of the base camp and commence the permitting process for the Osheki-1 exploration well.

Block 133

We acquired our interest in Block 133 through the Petrolifera acquisition in March 2011. Block 133 covers 764,320 gross acres. We are the operator of the block with a 100% working interest. The second exploration period required that 20.96% of this block's acreage be relinquished, which occurred upon the end of the second exploration period in October 2013. We are in the third exploration period of four. This period requires one exploration well to be drilled or the completion of 200 units of work, but is currently suspended pending the approval of a 2-D seismic and drilling environmental impact assessments ("EIA").

In 2014, we continued work to obtain the necessary environmental and social permits for future seismic programs. In 2015, we plan to continue EIAs.

Estimated Reserves

The following table sets forth our estimated reserves NAR as of December 31, 2014. 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. Our internal controls over reserve estimates include: 100% of our reserves are evaluated by an independent reservoir engineering firm, GLJ Petroleum Consultants Ltd., at least annually; and reconciliation and review controls are followed, including an independent internal review of assumptions used in the reserve estimates and presentation of the results of this internal review to our reserves committee.

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 25 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.

Our 2014 proved reserves additions were based on estimates generated through the integration of relevant geological, engineering, and production data, utilizing technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

The product prices that were used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions and/or distance from market. The average realized prices for reserves in the report are:

Light/Medium Oil (USD/bbl) - Brazil	$84.63
Natural Gas (USD/Mcf) - Brazil	$4.69
Oil and NGLs (USD/bbl) - Colombia	$88.63
Natural Gas (USD/Mcf) - Colombia	$4.43

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	Oil (Mbbl)	Natural Gas (MMcf)	Oil and Natural Gas (MBOE)
Proved			
Developed			
Colombia	27,866	983	28,030
Brazil	1,333	—	1,333
Total proved developed reserves	29,199	983	29,363
Undeveloped			
Colombia	6,178	—	6,178
Brazil	1,503	—	1,503
Total proved undeveloped reserves	7,681	—	7,681
Total proved reserves	36,880	983	37,044
Probable (1)			
Developed			
Colombia	7,521	333	7,577
Brazil	597	—	597
Total probable developed reserves	8,118	333	8,174
Undeveloped			
Colombia	3,790	866	3,934
Brazil	1,076	2,168	1,437
Total probable undeveloped reserves	4,866	3,034	5,371
Total probable reserves	12,984	3,367	13,545
Possible (1)			
Developed			
Colombia	6,141	500	6,224
Brazil	700	—	700
Total possible developed reserves	6,841	500	6,924
Undeveloped			
Colombia	6,438	876	6,584
Brazil	1,651	1,173	1,847
Total possible undeveloped reserves	8,089	2,049	8,431
Total possible reserves	14,930	2,549	15,355

(1) Largely as a result of the current low commodity price environment, we reevaluated our business strategy with a renewed focus on balancing the return and risk of our exploration and development projects. As a result, on February 19, 2015, we made the decision to cease all further development expenditures on the Bretaña field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. The high capital investment, associated debt financing and long-term payout horizon of this project does not align with our shift in strategy as announced on February 2, 2015.As noted in our press release dated February 2, 2015, the December 31, 2014 probable and possible reserves associated with Peru were likely to be reduced subsequent to year-end as a result of new drilling data on the Bretaña Sur 95-3-4-1X appraisal well. Considering the current low commodity price environment and the significant aspects of the Bretaña field project which were no longer in line with our strategy, our Board of Directors determined that they would not proceed with the further capital investment required to develop the Bretaña field. As a result of this decision, all probable and possible reserves associated with the field were reclassified as contingent resources in a report with an effective date of January 31, 2015. These probable and possible reserves are therefore excluded from this table. Further as a result, $265.1 million of unproved properties relating to Block 95 were impaired at December 31, 2014.

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Proved Undeveloped Reserves

At December 31, 2014, we had total proved undeveloped reserves NAR of 7.7 MMBOE (December 31, 2013 - 8.4 MMBOE), including 6.2 MMBOE in Colombia (December 31, 2013 – 6.0 MMBOE) and 1.5 MMBOE in Brazil (December 31, 2013 – 1.1 MMBOE). At December 31, 2013, we had 1.3 MMBOE of proved undeveloped reserves NAR in Argentina, which were sold as part of the sale of the Argentina business unit during 2014. Approximately 57%, 12% and 11% of proved undeveloped reserves, respectively, are located in our Moqueta, Costayaco and Jilguero fields in Colombia and 20% are in the Tiê field in Brazil. None of our proved undeveloped reserves at December 31, 2014, 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, 2013	8.4
Converted to proved producing	(7.1)
Discoveries and extensions	4.0
Sale	(1.3)
Improved recovery	0.7
Technical revisions	3.0
Balance, December 31, 2014	7.7

In 2014, we converted 7.1 MMBOE, or 84% of year-end 2013 proved undeveloped reserves, to developed status. In 2014, we made investments, consisting solely of capital expenditures, of $64.8 million in Colombia and $5.4 million in Brazil, associated with the development of proved undeveloped reserves. Approximately 84% of proved undeveloped reserves conversions occurred in the Costayaco, Moqueta and Jilguero fields in Colombia and 16% in the Tiê field in Brazil. The majority of proved undeveloped conversions occurred as a result of ongoing development activities in the Moqueta and Costayaco fields in Colombia, including infill drilling and a pressure maintenance project in both of these fields and an appraisal drilling program in the Moqueta field. Technical revisions include positive revisions resulting from better than expected production performance in the Costayaco and Moqueta fields. Additionally, significant proved undeveloped conversions occurred as a result of well recompletions and stimulation work on the Agua Grande formation in the Tiê field in Brazil. The sale of proved undeveloped reserves relates to the sale of our Argentina business unit on June 25, 2014.

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, 2014, 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.

The following table presents oil and NGL production NAR before inventory adjustments and losses from our Costayaco and Moqueta fields for the three years ended December 31, 2014:

	Year Ended December 31,					
	2014		2013		2012	
	Costayaco	Moqueta	Costayaco	Moqueta	Costayaco	Moqueta
Oil and NGL's, bbl	4,194,933	1,690,335	4,692,610	1,283,369	3,783,147	645,219
Average sales price of oil and NGL's per bbl	83.05	82.84	90.13	97.22	102.07	106.97

Operating expenses of oil and NGL's per bbl	15.50	12.06	11.29	16.58	12.63	26.14

We prepared the estimate of standardized measure of proved reserves in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification 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" for a year were in progress as of December 31, 2014, 2013 or 2012.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	—	—	3.00	1.60	—	—
Dry	2.00	2.00	1.00	0.50	3.00	2.50
In Progress	1.00	1.00	2.00	2.00	2.00	0.95
Development						
Productive	6.00	6.00	5.00	5.00	3.00	3.00
Dry	—	—	—	—	—	—
In Progress	3.00	3.00	—	—	2.00	2.00
Total Colombia	12.00	12.00	11.00	9.10	10.00	8.45
Argentina						
Exploration						
Productive	—	—	—	—		