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.

- 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.

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	—	—	—	—	1.00	0.35
Dry	—	—	3.00	1.70	2.00	1.35
In Progress	—	—	—	—	3.00	1.70
Development						
Productive	1.00	0.85	4.00	3.35	10.00	9.20
Dry	—	—	1.00	0.35	1.00	1.00
In Progress (1)	1.00	1.00	1.00	1.00	3.00	1.70
Total Argentina	2.00	1.85	9.00	6.40	20.00	15.30
Brazil						
Exploration						
Productive	—	—	—	—	—	—
Dry	2.00	2.00	2.00	2.00	—	—
In Progress	—	—	2.00	2.00	1.00	1.00
Development						
Productive	—	—	—	—	2.00	2.00
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Total Brazil	2.00	2.00	4.00	4.00	3.00	3.00
Peru						
Exploration						
Productive	—	—	1.00	1.00	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	1.00	1.00
Development						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	1.00	1.00	—	—	—	—
Total Peru	1.00	1.00	1.00	1.00	1.00	1.00

Total	17.00	16.85	25.00	20.50	34.00	27.75

(1) On June 25, 2014, we sold our Argentina business unit to Madalena.

In 2014, we also continued pressure maintenance projects in the Costayaco and Moqueta fields in Colombia.

As at February 24, 2015, the results of wells in progress at December 31, 2014, are as follows:

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
Colombia	1.00	1.00			3.00	3.00
Brazil	—	—	—	—	—	—
Peru	—	—	1.00	1.00	—	—
	1.00	1.00	1.00	1.00	3.00	3.00

Well Statistics

The following table sets forth our productive wells as of December 31, 2014:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia (1)	54.0	43.75	—	—	54.0	43.8
Brazil (2)	3.0	3.0	—	—	3.0	3.0
Peru	1.0	1.0	—	—	1.0	1.0
	58.0	47.8	—	—	58.0	47.8

(1) Includes 7.0 gross and net water injector wells and 54.0 gross and 36.2 net wells with multiple completions.
(2) Includes 2.0 gross and net wells with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2014:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia (1)	380,277	309,093	3,731,375	3,205,997	4,111,652	3,515,090
Brazil	5,786	5,786	41,947	41,947	47,733	47,733
Peru	—	—	5,732,274	5,732,274	5,732,274	5,732,274
	386,063	314,879	9,505,596	8,980,218	9,891,659	9,295,097

(1) Included in acres are blocks where relinquishments and acreage changes for which government approval was pending as of December 31, 2014. These pending approvals will result in a decrease of 0.9 million net acres in Colombia.

At December 31, 2014, our gross undeveloped acreage was located 60% in Peru (37% Blocks 123 and 129), 39% in Colombia and 1% in Brazil.

Business Strategy

We are focused on the South America oil and gas business with current operations in Colombia, Peru and Brazil. In today’s low commodity price environment we are taking prudent steps to ensure near term stability while positioning for growth in preparation for rising commodity prices in the future. A key piece in this strategy is the preservation of our strong balance sheet through reductions to our capital program, operating expenses, general and administrative costs and renegotiations of all service and transportation costs. For the capital program, only those projects that have immediate value additions or are contractual commitments will move forward, and all others will be deferred or canceled. Additionally, our exploration and development process is under review with the intent of high grading and enhancing our exploration success. The current process of prospect generation, selection, analysis and drilling decisions is under review. The exploration portfolio will be re-evaluated with a view to focusing on lower risk oil prospects and farming down higher risk longer term prospects. Whenever possible operatorship will be retained in order to maintain operational and financial control.

With a focus on cost control we aim to continue to grow organically over the long term, and, in the near term, we look to leverage off our financial strength, South American experience and in-country relationships to grow inorganically through the opportunistic acquisition of distressed assets and/or companies in our target region which we believe will arise during this low commodity price cycle. We will also look to strategically dispose of non-core assets as opportunities to do so present themselves.

Research and Development

We have not expended any resources on pursuing research and development initiatives. We utilize existing technology, industry best practices and continual process improvement to execute our business plan.

Marketing and Major Customers

Colombia

Our oil in Colombia is good quality light oil, with 94% of production coming from the Putumayo Basin with an average API of approximately 29°. Ecopetrol is the main purchaser of our crude oil production in Colombia and the source of a significant portion of our revenues. Sales to Ecopetrol accounted for 52%, 46% and 85% of our consolidated revenues in 2014, 2013 and 2012, respectively.

We have entered into agreements to sell to Ecopetrol the volume of crude oil production produced in the Chaza, Santana and Guayuyaco Blocks (the “Putumayo production”). The volume of crude oil does not include the volume of oil corresponding to royalties taken in kind, but does include volumes relating to HPR royalties. These agreements are subject to renegotiation periodically and generally contain mutual termination provisions with 30 days notice. These agreements will expire November 30, 2015. We may, but are not obligated to, sell up to 100% of our Putumayo production to Ecopetrol, provided Ecopetrol has the capacity to receive it. We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and trucking and through the transportation and logistics assets of CENIT Transporte y Logistica de Hidrocarburos S.A.S ("CENIT").

Prior to the end of January 2012, the sales point for our sales to Ecopetrol of the Putumayo production to be exported through the Port of Tumaco on the Pacific coast of Colombia was a point in the Putumayo Basin. Beginning in February 2012, the sales point was changed to the Port of Tumaco. Due to the change in the sales point for Putumayo production to the Port of Tumaco, we entered into crude oil transportation agreements with Ecopetrol.

In 2013, Ecopetrol transferred its hydrocarbon transport and logistics assets to its wholly-owned subsidiary, CENIT. We have entered into transportation agreements (the “Transportation Agreements”) with CENIT. These agreements will expire November 30, 2015. Pursuant to the Transportation Agreements we pay a transportation tariff and transportation tax for the transportation of the Putumayo production from the Putumayo Basin to the Port of Tumaco. Pursuant to the Transportation Agreements, each of Gran Tierra Energy Colombia Ltd. and Petrolifera Petroleum (Colombia) Limited have the right to transport up to 10,000 bopd, subject to availability of capacity, of crude oil production from the Chaza, Santana and Guayuyaco Blocks in Colombia: (1) from Santana Station to CENIT’s facility at Orito through CENIT’s Mansoya – Orito Pipeline, and (2) from CENIT’s facility at Orito to the Port of Tumaco through CENIT’s Orito – Tumaco Pipeline. We can request that CENIT transport additional crude oil in excess of 20,000 bopd through the pipelines on the same terms, which CENIT may do at its sole discretion.

Generally, under these agreements, CENIT is liable (subject to specified limitations) for pollution clean up costs resulting from incidents during transportation. The cost of oil lost during transportation is shared by the parties that ship oil on the pipeline, in proportion to their share of total volumes shipped. Currently we have Firm Capacity Transportation Agreements for 6,000 bopd, of which 3,000 bopd are under ship or pay agreements and 3,000 bopd are under ship and pay agreements, which are in place for eight years; the remainder of our Putumayo production is transported through the Transportation Agreements.

In the event that we do not sell all of our production to Ecopetrol, we sell to alternative purchasers, which have included: Gunvor Colombia C.I. S.A.S ("Gunvor CI"), Hocol S.A. (“Hocol”), Pacific Stratus Energy Colombia Corp. (“PSE”), Core Petroleum LLC ("Core") and Gunvor S.A. (“Gunvor”). Sales to Gunvor CI accounted for 32% of our consolidated revenues during the year ended December 31, 2014. Sales to the other alternative customers noted above combined accounted for 6% of our consolidated revenues during the year ended December 31, 2014.

We are under no obligation to sell any oil to our alternative purchasers until we specify for a particular day the amount of oil we wish to sell to them. Oil is delivered and sold to Gunvor CI at the Costayaco battery where oil is loaded into trucks. On November 25, 2014, the Gunvor CI agreements were extended by one year to December 3, 2015. Oil is delivered to Hocol at facilities at Babillas Station and the sales point is the Port of Coveñas upon oil export. Oil is delivered to PSE at facilities of Guaduas Station and the sales point is the Port of Coveñas. Oil is delivered to Core and Gunvor via pipeline to the Port of Esmeraldas, Ecuador and the sales point is when oil is loaded into an export tanker.

The majority of the oil produced is transported by pipeline. Varying amounts of oil are trucked: (1) from Santana Station to Ecopetrol’s storage terminal at Orito, a distance of approximately 46 kilometers; (2) from the Costayaco field to Ecopetrol’s storage terminal at Neiva (Dina Station), approximately 350 kilometers north of the Chaza Block; (3) from the Costayaco field to Hocol´s unloading facilities at Neiva (Babillas Station), approximately 350 kilometers north of the Chaza Block; (4) from the Costayaco field to the Atlántico Oil Terminal in Barranquilla, a distance of approximately 1,500 kilometers; (5) from the Costayaco field to PSE´s unloading facilities at Guaduas (Guaduas Station), approximately 700 kilometers north of the Chaza Block; (6) from the Garibay field to facilities at Cusiana Station, a distance of approximately 75 kilometers; and; (7) from the Llanos 22 field to facilities at Cusiana Station, a distance of approximately 35 kilometers.

We receive revenues for our Colombian oil sales in U.S. dollars. Oil prices for sales of our crude oil are defined by agreements with the purchasers of the oil and are based generally on an average price for crude oil, such as West Texas Intermediate ("WTI") or Brent, with adjustments such as for quality, specified fees, transportation fees and transportation tax.

Ecopetrol and CENIT are majority owned by the government of Colombia. We could be materially impacted by renegotiation of our agreements with Ecopetrol and CENIT, which agreements have a term of 12 months, but are cancelable by either party on two weeks’ notice. CENIT also has the ability to increase port fees once during each contract term on 30 days’ notice.

Brazil

Petróleo Brasileiro S.A (“Petrobras”) is the main purchaser of our oil production from Block 155 in Brazil. Sales to Petrobras accounted for 5%, 4% and 2% of our consolidated revenues in 2014, 2013 and 2012, respectively. Oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. Oil prices for sales to Petrobras are based on the monthly average Dated Brent price less a refining and quality discount.

There were no sales in any countries other than Colombia, Brazil and Argentina in 2014, 2013 or 2012.

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

Competition

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

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

Geographic Information

Information regarding our geographic segments, including information on revenues, assets, expenses and net income, can be found in Note 5 to the Consolidated Financial Statements, Segment and Geographic Reporting, in Item 8 “Financial Statements and Supplementary Data”, which information is incorporated by reference here. Long lived assets are Property, Plant and Equipment, which includes all oil and gas assets, furniture and fixtures, automobiles and computer equipment. No long lived assets are held in our country of domicile, which is the United States of America. "All Other" assets include assets held by our corporate head office in Calgary, Alberta, Canada. Because all of our exploration and development operations are in South America, we face many risks associated with these operations. See Item 1A “Risk Factors” for risks associated with our foreign operations.

Regulation

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

Colombia

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

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

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

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

When operating under a contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, except for royalty volumes which are collected by the ANH (or its designee), depending on the type of contract. The contractor can market the hydrocarbons in any manner whatsoever, subject to a limitation in the case of natural emergencies where the law specifies the manner of sale.

Peru

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

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

The Peruvian Constitution and the Organic Hydrocarbon Law states that a license contract does not provide for a transfer or lease of property over the area of the exploration or exploitation. In accordance with a license contract, a third party acquires the right to explore for or exploit hydrocarbons in a specified area and PeruPetro (the entity that holds the Peruvian state interest) transfers the property right in the extracted hydrocarbons to the third party, who must pay a royalty to the state.

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

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

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

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

Brazil

In Brazil, Law No. 2004 enacted in 1953 created the state monopoly of the petroleum industry and Petrobras, a state-owned legal entity, which was the sole company conducting exploration and production activities in Brazil. The Brazilian Federal Constitution enacted on October 5, 1988, continued this state monopoly of the petroleum industry.

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

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

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

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

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

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

Concessionaires are required under Law No. 9478/97 to pay the government dues and fees, in addition to the charges for sale of pre-bid data and information. The ANP has the power to determine the criteria under which the Government Take will be assessed within the limits established by Federal Decree No. 2705/98. Government Take comprises (i) signature bonus, (ii) royalties, (iii) special participation and (iv) area rentals. Part of the Government Take is passed on to States and Municipalities and other government branches according to law.

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

In addition to the risk factors referenced in the Peru section above, see "Our Business is Subject to Local Legal, Political and Economic Factors Which are Beyond Our Control, Which Could Impair Our Ability to Expand Our Operations or Operate Profitably" in Item 1A “Risk Factors” for information regarding the regulatory risks that we face.

Environmental Compliance

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

In 2015, we plan to spend approximately $4.3 million in Colombia on capital programs related to environmental studies, community consultations and environmental remediation. In Peru, costs for environmental and social projects are expected to be approximately $5.1 million and mainly relate to environmental and social impact assessments, implementation of environmental management plans and environmental and social monitoring activities. In Brazil, we plan to spend approximately $1.3 million on costs for environmental projects including waste management.

In 2014, the following environmental activities occurred:

- In Colombia, we received the Exploitation License for the Moqueta field, the amendment of the Environmental License for the Mocoa River Exploratory Drilling Area, the amendment of the Global License for the Costayaco field and the Environmental License for the Cabañas Exploratory Drilling Area. We started the in-situ bioremediation of contaminated soil in the Mary battery, which contamination is believed to have been the result of guerrilla activity that occurred in 1998. We commenced measures to control any oil leakage resulting from illegal valves installed on the section of pipeline from Uchupayaco to Sanata, removed the illegal valves and recovered the affected soil and bodies of water after the affected area was secured by the government. Contaminated material was transported to specialized companies with the necessary environmental licenses for treatment and disposal, in accordance with our policy. A number of other minor incidents within our facilities occurred, each of which caused small quantities of oil to be spilled. In each of these minor incidents, we completed a full clean up of the affected area.

- In Peru, we continued the Environmental Monitoring Program for drilling activities on Block 95 and started an Environmental Monitoring Program for seismic activities on Block 107. We continued partnerships with the Pacaya Samiria Natural Reserve, the Pucacuro National Reserve, the Forest Protection San Matías San Carlos (Block 107) and the Regional Conservation Area Pintuyacu Nanay Chambira & Pucacuro Natural Reserve (Blocks 123 and 129). We obtained the necessary permits for long-term test production and the relocation of a well pad on Block 95 and a seismic program in Block 107. We continue to work towards obtaining permits for drilling activities on Block 107 and exploration projects on Blocks 133, 123 and 129.

- In Brazil, we implemented controls and field techniques to manage the social and environmental impact of seismic activities on our new exploration blocks in the Recôncavo Basin, completed work to improve the drainage system and constructed barriers on the Tiê field to contain minor spills and continued a reforestation project.

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

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

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

Community Relations Initiatives

In 2014, we continued standardized quarterly reporting on our community relations initiatives. We prioritize hiring local people and companies in all our operations. In support of sustainable development, we have a program of community investment in all of our operating areas. These investments are based on local needs as evidenced in socio-economic baseline studies and consultation with the communities and government authorities so that our investments meet their requirements and have the highest positive impact possible. We also continuously monitor the concerns and expectations of the communities where we operate to ensure our plans and activities are carried out in a manner that takes into account the communities' needs and compensates and mitigates any possible adverse impacts.

Projects undertaken in 2014 were as follows:

Colombia

In 2014, our most significant community relations initiatives and investments were made in the municipalities of Mocoa, Villagarzon and Puerto Guzman in the Department of Putumayo and the Municipality of Piamonte in the Department of Cauca.
We made voluntary investments in relation to community support during drilling projects on the Chaza Block. Below is a description of our $2.5 million voluntary social investment, responding to the needs identified and prioritized by the communities in those areas in which we operate.

- Provided support for education, including providing funding for learning technology such as computers.

- Supported community groups in projects that benefited local families with agriculture projects, including a widely recognized pepper production project with 58 formerly coca-growing families.

- Sponsored a number of projects to strengthen cultural identity including local festivals that celebrate indigenous culture and history and costs for local delegates to attend a conference of indigenous peoples from various areas in the country.

- Supported numerous programs for improving local infrastructure such as paving streets in urban areas, construction of cultural venues, construction of sport facilities and computer rooms and provision of materials for electric power supply in rural areas.

- Implemented projects related to health, basic sanitation and housing including construction of a hospital emergency room and improving health facilities and housing.

- Provided strong communications with the communities and undertook focused consultations with ethnic minorities.

Peru

In 2014, we invested approximately $2.0 million in the following activities:

- On Block 95, we made improvements to the Bretaña community health center and provided an electricity generator to the town.

- Held consultation and education sessions with dozens of communities located on our blocks and developed technical workshops with indigenous organizations on the sustainable use of natural resources.

- Provided healthcare support services to communities and supported medical campaigns in our blocks.

- Provided employment to residents in our blocks.

- Implemented a community environmental monitoring program.

- Provided 500 water filters to families in outlying communities.

- Supported initiatives to provide national identification cards to undocumented people in remote rural communities to enable them to work and access health, education and other social programs.

- Implemented a turtle conservation project in the Pacaya Samiria National Reserve.

- Supported conservation monitoring activities in the Pucacuro National Reserve, including financing the construction of a conservation research center.

Brazil

In 2014, we invested approximately $80,000 in supporting schools in the municipality of Pojuca, in the Salvador region, including the “Prosa da minha terra” book creation project, benefiting 250 children, promoting literacy, creativity and self-esteem.

Employees

At December 31, 2014, we had 473 full-time employees: 52 located in the Calgary corporate office, 291 in Colombia (150 staff in Bogota and 141 field personnel), 88 in Peru (71 office staff in Lima and 17 field staff) and 42 in Brazil (30 office staff in Rio de Janeiro and Salvador and 12 field staff). None of our employees are represented by labor unions and we consider our employee relations to be good.

Available Information

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

Item 1A. Risk Factors

Risks Related to Our Business

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

During 2012 and 2013, guerrilla activity in Colombia increased significantly, and the activity level remained high in 2014 and into 2015 to date. This increased activity creates a greater risk for our operations and our employees and our mitigation activities may not be adequate to alleviate the risks arising from such guerrilla activity.

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

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Catatumbo, Cauca, Llanos, Sinu-San Jacinto, Middle Magdalena and Lower Magdalena Basins. The Putumayo and Catatumbo regions have been the breeding place of guerrilla activity. Pipelines have been primary targets because such pipelines cannot be adequately secured due to the sheer length of such pipelines and the remoteness of the areas in which the pipelines are laid. The Ecopetrol-operated Trans-Andean oil pipeline (the "OTA pipeline”) which transports oil from the Putumayo region and upon which we materially rely has been targeted by these guerrilla groups. Starting in 2008, the OTA pipeline experienced outages of various lengths. In 2012, the OTA pipeline was shutdown for over 162 days and the shutdown had a material adverse effect on our deliveries to Ecopetrol and our financial performance for 2012. Recently we have experienced outages from October 2012 through to January 2015. In 2013, the OTA pipeline was shutdown for approximately 229 days. In 2014, the OTA pipeline was shutdown for approximately 180 days, which included 49 days as a result of a landslide. We have employed mitigation strategies as discussed in the risk "We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses" later in this section. Such disruptions may continue indefinitely and could harm our business.

In 2013, we experienced damage to two of our facilities in the amount of approximately $0.8 million. Production of about 330 bopd was shut in for 39 days. No long-term environmental damage or injury to personnel occurred in either incident. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

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

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

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

Our revised preliminary capital program for 2015 calls for approximately $140 million to fund our exploration and development, which we intend to fund through cash flows from operations and cash on hand. Funding this program relies in part on oil prices remaining close to current levels or higher and other factors to generate sufficient cash flow. Oil prices were very volatile at the end of 2014 and have remained at low levels in the first part of 2015. We have restricted activity and lowered our planned capital spending for 2015. Low oil prices affect our debt capacity and the amount of money we can borrow using our oil reserves as collateral, as well as the amount of cash we are able to generate from current operations. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our business plan which would cause us to further decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

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

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

The majority of our oil in Colombia is contracted for delivery to a single pipeline owned by CENIT S.A. ("CENIT"), a wholly-owned subsidiary of Ecopetrol, and operated by Ecopetrol. Sales of oil have been and could continue to be disrupted by damage to this pipeline or displaced by Ecopetrol’s use of the pipeline itself. In addition, CENIT has a monopoly over pipeline transportation from the area, which limits our ability to negotiate on pipeline tariff increases and our costs may increase as a result. Under our transportation contract with CENIT, the delivery point for our oil is at the end of the pipeline. This creates a risk of loss of oil due to sabotage by guerrillas or theft from the pipeline which may result in reduced revenues and increased clean-up or third party costs. We have attempted to mitigate the risk of increased costs with insurance and are investigating potential ways to mitigate and reduce revenue risk. CENIT and Ecopetrol maintain responsibility for clean-up of any spilled oil and for pipeline repair.

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, June, July and August of 2009, June, August, and September 2010, February 2011, February to August of 2012 and October 2012 to January 2015, as a result of sabotage by guerrillas. In addition, there is competition for space in these pipelines, and additional discoveries in our area of operations by other companies could decrease the pipeline capacity available to us. Trucking is an alternative to transportation by pipeline; however, it is generally more expensive and carries higher safety risks for us, our employees and the public.

Alternative transportation arrangements in Colombia allowed us to deliver our full production during 2013 and the first nine months of 2014; however, these deliveries result in reduced realized prices compared to the Ecopetrol operated OTA pipeline deliveries and are not necessarily sustainable. When disruptions are of a long enough duration, our sales volumes may be lower than normal, which will cause our cash flow to be lower than normal, and if our storage facilities become full, we can be forced to reduce production.

In Peru, any oil produced may be delivered via river barge. Suppliers of barges that meet our high standards for safety and reliability are limited and this may affect our ability to deliver the production volumes we have planned for the test.

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

During the year ended December 31, 2014, we sold to Ecopetrol, one other main customer and three other customers. While oil prices in Colombia are related to international market prices, lack of competition and reliance on a limited number of customers for sales of oil may diminish prices and depress our financial results.

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

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

We operate our business in Colombia, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as nationalization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. Our production in Brazil was shut in for three weeks in October 2013 as a result of a strike by employees of Petrobras which affected the crude oil receiving terminal we use in the Recôncavo Basin, and we have experienced minor delays in trucking operations due to demonstrations and strikes in our operating area during the year ended December 31, 2014. We do not know how long any such labor action will last, and if it lasts a significant amount of time, it may affect our ability to meet our production targets.

South America has a history of political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including the imposition of additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Colombia, Peru or Brazil or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

Changes in laws in the jurisdiction in which we operate or expand into with the effect of favoring local enterprises, and changes in political views regarding the exploitation of natural resources and economic pressures, may make it more difficult for us to negotiate agreements on favorable terms, obtain required licenses, comply with regulations or effectively adapt to adverse economic changes, such as increased taxes, higher costs, inflationary pressure and currency fluctuations. In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for business. These licenses and agreements may be susceptible to revision or cancellation and legal redress may be uncertain or delayed.

Recently, in the Department of Putumayo in Colombia where we operate, despite a company’s compliance with legislative requirements for prior consultation of communities and minority ethnic groups and the receipt of the necessary permits to drill and operate, new ethnic groups have been threatening, and in some cases using, the Judicial Branch of the Government, Superior Court of the Judicial District of Mocoa (the “Local Court”) to require that they be consulted, and thereby obtain benefits from companies operating in the Department of Putumayo as a result of those consultations. The Local Court has the ultimate jurisdiction to determine, upon a writ for protection or tutela, by an ethnic group (i) whether there has been a violation of a fundamental right to prior consultation by act or omission of a public authority or individual and (ii) whether the ethnic

group is legitimate. If the Local Court determines that there has been a violation and the ethnic group is legitimate despite receipt by the company of its proper governmental permits, the Local Court has the power to invalidate a company's permits and force the company to cease operations immediately until such time as the company can successfully appeal to the Supreme Court to overturn the Local Court's decision or prior consultations are completed and the permits effective once again.
Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government and judicial authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired and, if we are faced with a tutela, our operations in the area(s) governed by a Local Court's order may be shut down for a period of time thereby causing significant harm to our business in Colombia.

Recently in Brazil, environmental regulations related to fracture stimulation drilling have been under review by national agencies. 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. We acquired Blocks REC-T-86, REC-T-117 and REC-T-118 in Bid Round 11 and these blocks may be affected by the same or a similar injunction as the one placed on blocks acquired in Bid Round 12. Until this situation is resolved, the expansion of our drilling operations in Brazil may be limited which would harm our business in Brazil.

Almost All of Our Cash and Cash Equivalents is Held Outside of Canada and the United States, and if We Determine to, or Are Required to, Repatriate These Funds, We Could Be Subject to Significant Taxes.

At December 31, 2014, 87% of our cash and cash equivalents was held by subsidiaries and partnerships outside of Canada and the United States. This cash is generally not available to fund domestic or head office operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay taxes in certain jurisdictions on the distribution of accumulated earnings.

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

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

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

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

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

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

Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations

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

As discussed in Note 12 to the Consolidated Financial Statements in Part II, Item 8 below, our production from the Costayaco Exploitation Area is subject to the HPR royalty, which 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. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which we contested because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. We also believe that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. We supplemented our claim on May 30, 2013. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that we breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. We filed a response to the ANH's counterclaim and filed our comments on the ANH defense to our claim. The ANH filed an amended counterclaim and we filed a response to the ANH's amended counterclaim. As at December 31, 2014, total cumulative production from the Moqueta Exploitation Area was 4.2 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $64.1 million. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as we do not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $40.6 million as at December 31, 2014. At this time no amount has been accrued in the financial statements as we do not consider it probable that a loss will be incurred.

Our Business May Suffer if We do Not Attract and Retain Talented Personnel.

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

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

Maintaining Good Community Relationships and Being a Good Corporate Citizen May Be Costly and Difficult to Manage.

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

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

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

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. We are also exposed to transaction risk on settlement of payables and receivables denominated in foreign currency. We have purchased non-deliverable foreign exchange contracts to hedge some of the transaction risk related to our Colombian income tax payable. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Production in Brazil is invoiced and paid in Brazilian Reals. Between September 1, 2005 and February 24, 2015, the exchange rate of the Brazilian Real has varied between 1.56 Reals to one U.S. dollar to 2.83 Reals to the U.S. dollar, a variance of 76%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the Colombian peso weakened by 24% against the U.S. dollar in the year ended December 31, 2014, resulting in a foreign exchange gain.

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

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

Further, we operate in remote areas and may rely on helicopter, boats or other transportation methods. Some of these transport methods may result in increased levels of risk and could lead to operational delays which could effect our ability to add to our reserve base and/or produce oil, serious injury or loss of life and could have a significant impact on our reputation or cash flow. Additionally, some of this equipment is specialized and may be difficult to obtain in our areas of operations, which could hamper or delay operations, and could increase the cost of those operations.

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

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

The government in Brazil requires us to register funds that enter and exit the country with the central bank. In Brazil and Colombia, all transactions must be carried out in the local currency of the country. Exchange controls may prevent us from transferring funds abroad.

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

Tax law changes can impact the after tax profits available for expatriation. For example, in the fourth quarter of 2014 the Colombian government approved tax legislation increasing the rate of tax applicable to ordinary income from 34% in 2014 to 39% for 2015, 40% for 2016, 42% for 2017 and 43% for 2018. In the same legislation, the Colombian government also instituted a new "wealth tax" payable on the net equity of our Colombia business units at a rate of 1.15% for 2015, 1% for 2016 and 0.4% for 2017.

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

We expect that our cash flow from existing operations and cash on hand will be sufficient to fund our currently planned activities. We may require additional capital to expand our exploration and development programs to additional properties. We may be unable to obtain additional capital required.

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

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

Negative Political Developments in Colombia May Negatively Affect Our Proposed Operations.

Adverse political incidents may generate social unrest which could impact our operations and oil deliveries in Colombia. Peace process negotiations between the government and FARC may not generate the intended outcome for both parties. With the use of arms, and other methods of influence, the FARC may place pressure on organizations and communities that are in areas of operations of the company. These communities, and affiliated organizations, can generate protests to attract the attention of government. These communities may make further use of the Local Court by filing a tutela, or writ of protection, to stop operations in Colombia until such time as these new ethnic communities obtain further consultations and benefits from companies operating in Colombia. Protests or other demonstrations may establish blockades, or the issuance of a tutela by a Local Court, could cause interruptions of operations, deliveries, and other disruptions to our work programs in the affected area.

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

Peru held a national election in June 2011 after which a new political regime was elected on a left-populist platform. The government has said that the past decade prioritized the strengthening of democracy with economic growth, while the current government will enhance social inclusion to benefit the neediest. This political regime may adopt new policies, laws and regulations that are more hostile toward foreign investment which may result in the imposition of additional taxes, the adoption of regulations that limit price increases, termination of contract rights, or the expropriation of foreign-owned assets. Such actions by the elected political regime could limit the amount of our future revenue in that country and affect our results of operations.

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

The Shining Path Guerilla group has been active in Peru since the early 1980's and, at one point, was active throughout the country. Recently, the group's activity has been confined to small areas of Peru and operations have been hampered by the capture of many high profile leaders and membership has fallen dramatically. During April 2012, 30 people working on the Camisea natural gas project in central Peru were kidnapped. Most of the workers were released after a short period of time, and the remainder were freed within a few days. The kidnapping was attributed to the Shining Path Guerilla group. Camisea is a very large, high profile project in an area where the group continues to be active. Our operations in Peru are in a different region, with no known activity by the group. Other groups may be active in other areas of the country and possibly our operational areas. Recently there have been security incidents and incidents of social unrest in and around our operating areas, particularly Block 107. We are monitoring the situation and increasing security measures as required. Nevertheless, we are concerned about the security of our operations in Peru and mitigate our risks through good relationships with local communities and stakeholders as well as strong security procedures.

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

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

- expand our systems effectively or efficiently or in a timely manner;

- allocate our human resources optimally;

- identify and hire qualified employees or retain valued employees; or

- incorporate effectively the components of any business that we may acquire in our effort to achieve growth.

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

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

Colombia is among several nations whose eligibility to receive foreign aid from the United States is dependent on its progress in stemming the production and transit of illegal drugs, which is subject to an annual review by the President of the United States. Although Colombia is currently eligible for such aid, Colombia may not remain eligible in the future. A finding by the President that Colombia has failed demonstrably to meet its obligations under international counternarcotics agreements may result in any of the following:

- all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended;
- the Export-Import Bank of the United States and the Overseas Private Investment Corporation would not approve financing for new projects in Colombia;

- United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes; and
- the President of the United States and Congress would retain the right to apply future trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with ANH and Ecopetrol and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets.

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

We Are Subject to the U.S. Foreign Corrupt Practices Act, a Violation of Which Could Adversely Affect Our Business.

The U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions prohibit corporations and individuals, including us and our employees, from making improper payments to non-U.S. officials and certain other individuals and organizations for the purpose of obtaining or retaining business or engaging in certain accounting practices. We do business and may do future business in countries in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations, international organizations, or private entities. As a result, we face the risk of unauthorized payments or offers of payments by employees, contractors and agents of ours or our subsidiaries or affiliates, even though these parties are not always subject to our control or direction. It is our policy to implement compliance procedures to prohibit these practices. However, our existing safeguards and any future improvements may prove to be less than effective or may not be followed, and our employees, contractors, agents, and partners may engage in illegal conduct for which we might be held responsible. Also, the FCPA contains certain accounting standards which obligate us to maintain accurate and complete books and records and a system of effective internal controls. These accounting provisions are very broad and a violation can occur even if there is no evidence of a bribe. The U.S. government is actively investigating and enforcing the FCPA and similar laws against companies and individuals. A violation of any of these laws, even if prohibited by our policies, may result in criminal or civil sanctions or other penalties (including profit disgorgement), could disrupt our business and could have a material adverse effect on our business. Actual or alleged violations could damage our reputation, be expensive to investigate and defend, and impair our ability to do business. A number of countries, including Canada, have strengthened their anti-corruption legislation. These laws prohibit both domestic and international bribery. There is a risk that an act of corruption can result in a violation of not only the FCPA, but also the laws of several other countries.

Our Business Could Be Negatively Impacted by Security Threats, Including Cybersecurity Threats as Well as Other Disasters, and Related Disruptions.

Our business processes depend on the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure in response to our changing needs. It is critical to our business that our facilities and infrastructure remain secure. Although we employ data encryption processes, an intrusion detection system, and other internal control procedures to assure the security of our data, we cannot guarantee that these measures will be sufficient for this purpose. The ability of the information technology function to support our business in the event of a security breach or a disaster such as fire or flood and our ability to recover key systems and information from unexpected interruptions cannot be fully tested and there is a risk that, if such an event actually occurs, we may not be able to address immediately the repercussions of the breach or disaster. In that event, key information and systems may be unavailable for a number of days or weeks, leading to our inability to conduct business or perform some business processes in a timely manner. We have implemented strategies to mitigate impacts from these types of events.

We have expended significant time and money on the security of our facilities and on our information technology infrastructure including testing of our security at our facilities and infrastructure. If our security measures are breached as a result of third-party action, employee error or otherwise, and as a result our data becomes available to unauthorized parties, we may lose our competitive edge in certain of our business activities and our reputation may be damaged. If we experience any breaches of our network security or sabotage, we might be required to expend significant capital and other resources to remedy, protect against or alleviate these and related problems, and we may not be able to remedy these problems in a timely manner, or at all. Because techniques used by outsiders to obtain unauthorized network access or to sabotage systems change frequently and generally are not recognized until launched against a target, we may be unable to anticipate these techniques or implement adequate preventative measures.

We have had past security breaches to our infrastructure, and, although they did not have a material adverse effect on our operations or our operating results, there can be no assurance of a similar result in the future. Our employees have been and will continue to be targeted by parties using fraudulent “spoof” and “phishing” emails to misappropriate information or to introduce viruses or other malware through “trojan horse” programs to our computers. These emails appear to be legitimate emails sent by us but direct recipients to fake websites operated by the sender of the email or request that the recipient send a password or other confidential information through email or download malware. Despite our efforts to mitigate “spoof” and “phishing” emails through education, “spoof” and “phishing” activities remain a serious problem that may damage our information technology infrastructure.

Risks Related to Our Industry

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

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

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs.

Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and technical conditions. While we will endeavor to effectively manage these conditions, we may not be able to do so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

Estimates of probable and possible reserves are inherently imprecise. When producing an estimate of the amount of oil that is recoverable from a particular reservoir, 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. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of probable and possible reserves are by their nature much more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

In addition, the quantity and value of our reserves directly effects our ability to access certain kinds of external financing that uses our reserves as collateral. Low oil prices diminish the value of our oil reserves, thus diminishing not only current cash flow, but debt capacity and access to other forms of capital as well. This could impair our ability to carry out the exploration and development activity required to replace our reserves.

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

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for West Texas Intermediate ("WTI") per bbl has varied from $66 in 2006 to $98 in 2013, and $93 in the year ended December 31, 2014, demonstrating the inherent volatility in the market. The average Brent oil price per bbl was $111 in 2011, $112 in 2012, $109 in 2013 and $99.02 in the year ended December 31, 2014. At the end of 2014, oil prices declined sharply, and the effect of that decline is not apparent from the average price for the year. On December 31, 2014, the price of WTI was $53.27 per bbl and the price of Brent oil was $55.27 per bbl. Given the current economic environment and unstable conditions in the Middle East, North Africa, and Eastern Europe and the current supply of oil in world markets, the oil price environment is unpredictable and unstable. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations, financing available to us, and quantities of reserves recoverable on an economic basis.

Oil prices in Colombia are related to international market prices, but adjustments that are defined by contracts with offtakers may cause realized prices to be lower or higher than those received in North America. Oil prices in Brazil are defined by contract with the refinery and may be lower or higher than those received in North America.

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

Oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our exploration expenditures may not result in new discoveries of oil or natural gas in commercially viable quantities or at a commercially viable cost. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. For example, in January 2014, the Corunta-1 exploration well on the west flank of the Moqueta field encountered drilling problems prior to reaching the reservoir target on this long-reach deviated well, and the decision was made to abandon the well. The target location may be drilled again in the future with a revised drilling plan. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations. In addition, changes in the price of oil can affect the commercial success of our exploration activity. If the oil price declines drastically, such as it did at the end of 2014 and beginning of 2015, some projects that were previously considered commercially successful may not be at low oil price levels and may be deferred, which means that our short to medium term production and cash flow may be lower than previously anticipated. For example, 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.

Estimates of Oil and Natural Gas Reserves That We Make May Be Inaccurate and Our Actual Revenues May Be Lower and Our Operating Expenses May Be Higher Than Our Financial Projections.

We make estimates of oil and natural gas reserves, upon which we will base our financial projections. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Wells that are drilled may not achieve the results expected from interpretation of geological data. Economic factors beyond our control, such as world oil prices, interest rates and exchange rates, will also impact the value of our reserves. The process of estimating oil and gas reserves is complex, and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

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

If Oil and Natural Gas Prices Decrease, or Our Operating Results are Different Than We Expect, We May Be Required to Take Write-Downs of the Carrying Value of Our Oil and Natural Gas Properties.

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

In 2012, we recorded a ceiling test impairment loss of $20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. The farm-out agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period. In 2013, we recorded a $2.0 million ceiling test impairment loss in our Brazil cost center related to lower realized prices and an increase in operating costs. In the year ended December 31, 2013, we recorded a ceiling test impairment loss of $30.8 million in our Argentina cost center as a result of deferred investment and inconclusive waterflood results. In 2014, we recorded an impairment loss of $265.1 million in our Peru cost center related to drilling costs on Block 95.

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

We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. For example, the permitting process in Peru takes significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere. In Colombia, other drilling and development projects are being delayed, most significantly our Moqueta field development, because of delays at the Ministry of the Environment and other government departments. During the third quarter 2014, we received the Exploitation License for the Moqueta field, however delays in receiving it contributed to operational delays and higher development costs. In addition, environmental and social evaluation demands have increased in Colombia, causing permit processing to take longer than previously experienced in the areas where we operate and, in some areas where we operate, such as the Department of Putumayo, despite the receipt of the proper permits, there are new procedures being utilized by new ethnic communities to make further economic demands on operators to continue to operate in the region, such as the use of the Local Court to obtain a tutela, or writ of protection. These delays and demands are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations. For example, currently in Brazil, we are subject to restrictions on flaring natural gas, which have the impact of limiting our production capacity. We have examined other alternatives for producing and delivering the gas, however, however, to date, we have not been able to successfully implement any of these alternatives.

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

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

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

We are responsible for costs associated with abandoning and reclaiming some of the wells, facilities and pipelines which we use for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as “decommissioning.” We have determined that we require a reserve account for these potential costs in respect of our current properties and facilities at this time, and have booked such reserve on our financial statements. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy decommissioning costs could impair our ability to focus capital investment in other areas of our business. For example, our decision to not commit to further investment in the Bretaña field on Block 95 in Peru could accelerate the timing of significant decommissioning costs.

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

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires and spills. Earthquakes or weather related phenomena such as heavy rain, landslides, storms and hurricanes can also cause problems in drilling new wells. There are also risks in producing oil and natural gas from existing facilities. For example, in January 2014, the Corunta-1 exploration well on the west flank of the Moqueta field encountered drilling problems prior to reaching the reservoir target on this long-reach deviated well, and the decision was made to abandon the well. The target location may be drilled again in the future with a revised drilling plan. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. Incidents such as these can lead to serious injury, property damage and even loss of life. We generally obtain insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Environmental Risks May Adversely Affect Our Business.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require us to incur costs to remedy such discharge. For example, we have encountered difficulties maintaining the stability of the river shoreline at our drilling and production facilities at the Bretaña field on Block 95. We will have to invest money to remediate the shoreline even though we have suspended investment in the field while we evaluate options. The application of environmental laws to our business may cause us to curtail our production or increase the costs of our production, development or exploration activities.

Penalties We May Incur Could Impair Our Business.

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

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

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

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

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

Challenges to Our Properties May Impact Our Financial Condition.

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

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

If our property rights are reduced, whether by governmental action or third party challenges, our ability to conduct our exploration, development and production may be impaired. See the risk factor "Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations" for a description of our dispute with the ANH regarding royalties payable on our Chaza Block and the resulting challenge to our contract for that block.

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

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

Risks Related to Our Common Stock

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

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

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

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

- quarterly variations in our revenues and operating expenses; and

- additions and departures of key personnel.

- updated reserve estimates by independent parties.

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

We do Not Expect to Pay Dividends in the Foreseeable Future.

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Administrative Facilities

Our executive offices are located in Calgary, Canada. Our primary executive offices comprise approximately 29,000 square feet, which we lease for approximately $79,000 per month under a lease that expires on December 30, 2018. We lease administrative office space in Colombia, Peru and Brazil. We believe that our current executive and administrative offices are sufficient for our purposes or, to the extent that we need additional office space, that additional office space will be readily available to us.

Item 3. Legal Proceedings

As discussed above (see “Royalties”, above, in Item 1), Gran Tierra’s production from the Costayaco Exploitation Area is subject to the HPR royalty, which 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. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. Gran Tierra supplemented its claim on May 30, 2013. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH defense to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. As at December 31, 2014, total cumulative production from the Moqueta Exploitation Area was 4.2 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $64.1 million. At this time, no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $40.6 million as at December 31, 2014. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

Item 4. Mine Safety Disclosures

Not applicable.

End of Item 4

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 24, 2015.

Name	Age	Position
Jeffrey J. Scott	52	Executive Chairman of the Board; Director
Duncan Nightingale	56	Interim President and Chief Executive Officer
James Rozon	51	Chief Financial Officer
David Hardy	60	Vice-President, Legal, Secretary and General Counsel
Adrian Coral	41	President, Gran Tierra Energy Colombia
Carlos Monges	58	President, Gran Tierra Energy Peru

Jeffrey J. Scott, Executive Chairman of the Board. Mr. Scott has served as Executive Chairman of our Board since February 2015, and served as Chairman of our Board of directors since January 2005. Since 2001, Mr. Scott has served as President of Postell Energy Co. Ltd., a privately held oil and gas producing company. He has extensive oil and gas management experience, beginning as a production manager of Postell Energy Co. Ltd in 1985 advancing to President in 2001. Also, since February 2012, Mr. Scott has served as Executive Chairman of Sulvaris Inc., a private fertilizer technology company. Mr. Scott is also currently a director of Petromanas Energy Inc. He was previously a director of Tuscany International Drilling Inc., Essential Energy Services Trust, Suroco Energy, Inc., VGS Seismic Canada Inc., High Plains Energy Inc., Saxon Energy Services Inc., Galena Capital Corp. and Gallic Energy Ltd., all of which are publicly-traded companies. Mr. Scott holds a Bachelor of Arts degree from the University of Calgary, and a Masters of Business Administration from California Coast University.

Duncan Nightingale, Interim President and Chief Executive Officer. Mr. Nightingale joined Gran Tierra in September 2009, where he served in our Calgary, Canada office as our Vice President of Exploration from September 2009 to January 2011. He served in our Bogotá, Colombia office as our Senior Manager Project Planning and Exploration from January 2011 until August 2011 and in our Calgary office as Chief Operating Officer from August 2011 to February 2, 2015. On February 2, 2015, Mr. Nightingale was promoted to Interim President and Chief Executive Officer. Prior to joining Gran Tierra, Mr. Nightingale was Senior Vice President, Exploration & Production, at Artumas Group Inc., a Canadian oil and gas company focusing on exploration and development of hydrocarbon reserves in Tanzania and Mozambique, where he was responsible for Artumas Group’s exploration and production operations in Mozambique and Tanzania and management of its gas processing plant and power generation facility in Tanzania. Prior to Artumas Group, Mr. Nightingale was General Manager, Exploration & Production, with Dana Gas PJSC, a leading private sector natural gas company in the Middle East, where Mr. Nightingale was responsible for all of Dana Gas’s exploration and production operations and was responsible for a multi-million dollar exploration and development program in Kurdistan. Prior to Dana Gas, Mr. Nightingale was with Encana Corporation’s International Division from May 2002 until March 2007. From June 2002 until September 2003, he was the Country Manager in Qatar, responsible for managing Encana’s activities in Qatar, including the execution of exploration programs and new venture activity. From October 2003 until June 2006, he had similar responsibilities in the Sultanate of Oman, where he served as Encana’s Country Manager. Mr. Nightingale has a total of 30 years of corporate head office and resident in-country international operating experience, spanning all aspects of managing exploration programs, development and production operations, new business ventures, portfolio management and strategic planning. Mr. Nightingale graduated from the University of Nottingham in the U.K. with a Bachelor of Science degree with honors in Geology.

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

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

Adrian Coral, President, Gran Tierra Energy Colombia. Mr. Coral joined Gran Tierra in August 2006 as an operations engineer in Gran Tierra Energy Colombia, Ltd., and served in that capacity until February 2007. Mr. Coral rejoined Gran Tierra in August 2008 as Operations Director of Gran Tierra Energy Colombia, Ltd. He served in that capacity until September 2011, when he was promoted to Production Manager of Gran Tierra Energy Colombia, Ltd. Mr. Coral was promoted to Senior Operations Manager of Gran Tierra Energy Colombia, Ltd. in April 2013. On August 1, 2014, Mr. Coral was promoted to President, Gran Tierra Energy Colombia. Mr. Coral has a total of 18 years of experience as an engineer or manager in the oil and gas industry. Mr. Coral graduated from the Universidad de América – Bogotá D.C. with a degree as a Petroleum Engineer and from the School of Business Management – Bogotá D.C with degree in Project Management.

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

PART II

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

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

As of February 24, 2015, there were approximately: 35 holders of record of shares of our Common Stock and 276,108,951 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately six holders of record of 4,524,627 exchangeable shares which may be exchanged on a 1-for-1 basis into shares of our Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing nineteen holders of record of 5,558,518 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into shares of our Common Stock.

For the quarters indicated from January 1, 2013, through the end of the fourth quarter of 2014, the following table shows the high and low closing sale prices per share of our Common Stock as reported on the NYSE MKT.

	High	Low
Fourth Quarter 2014	$5.43	$3.11
Third Quarter 2014	$8.04	$5.54
Second Quarter 2014	$8.12	$6.97
First Quarter 2014	$7.74	$6.82
Fourth Quarter 2013	$7.92	$6.86
Third Quarter 2013	$7.36	$6.01
Second Quarter 2013	$6.53	$5.21
First Quarter 2013	$6.12	$5.00

Unregistered Sales of Equity Securities and Use of Proceeds

On November 13, 2014, we issued 9,500 shares of our common stock to one holder of exchangeable shares, Verne Johnson, which were issued by a subsidiary of Gran Tierra in a share exchange on November 10, 2005. The shares were issued to this holder in reliance on Regulation S promulgated by the SEC as the investor was not a resident of the United States.

Dividend Policy

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

Performance Graph

Item 6. Selected Financial Data
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

Statement of Operations Data

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Oil and natural gas sales	$559,398	$646,955	$503,467	$548,175	$359,302
Interest income	2,856	2,174	1,709	1,124	1,148
	562,254	649,129	505,176	549,299	360,450
Operating expenses	113,949	110,172	92,207	59,421	50,638
DD&A expenses	451,003	202,851	150,570	185,696	134,156
G&A expenses	51,249	41,115	46,659	52,344	37,373
Financial instruments loss (gain)	4,722	—	—	(1,354)	(43)
Other loss	—	4,400	—	—	—
Other gain	(2,000)	—	(9,336)	—	—
Equity tax	—	—	—	8,271	—
Gain on acquisition	—	—	—	(21,699)	—
Foreign exchange (gain) loss	(39,535)	(18,693)	28,727	(255)	16,672
	579,388	339,845	308,827	282,424	238,796
(Loss) income from continuing operations before income taxes	(17,134)	309,284	196,349	266,875	121,654
Income tax expense	(127,215)	(128,261)	(96,267)	(115,290)	(51,548)
(Loss) income from continuing operations	(144,349)	181,023	100,082	151,585	70,106
Loss from discontinued operations, net of income taxes	(26,990)	(54,735)	(423)	(24,668)	(32,934)
Net income (loss)	$(171,339)	$126,288	$99,659	$126,917	$37,172
INCOME (LOSS) PER SHARE					
BASIC					
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.51)	$0.64	$0.35	$0.55	$0.28
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(0.09)	(0.19)	0.00	(0.09)	(0.13)
NET INCOME (LOSS)	$(0.60)	$0.45	$0.35	$0.46	$0.15
DILUTED					
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.51)	$0.63	$0.35	$0.54	$0.27
	(0.09)	(0.19)	0.00	(0.09)	(0.13)

LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES					
NET INCOME (LOSS)	$(0.60)	$0.44	$0.35	$0.45	$0.14

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Balance Sheet Data

	As at December 31,				
	2014	2013	2012	2011	2010
Cash and cash equivalents	$331,848	$428,800	$212,624	$351,685	$355,428
Working capital (including cash)	239,824	245,827	222,468	213,100	265,835
Oil and gas properties	1,117,931	1,250,070	1,196,661	1,036,850	721,157
Deferred tax asset - long-term	601	1,407	1,401	4,747	—
Total assets	1,714,050	1,904,550	1,732,875	1,626,780	1,249,254
Deferred tax liability - long-term	175,324	177,082	225,195	186,799	204,570
Total long-term liabilities	211,999	208,077	250,059	207,633	210,075
Shareholders' equity	1,276,685	1,429,908	1,291,431	1,174,318	886,866

On June 25, 2014, we 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. In accordance with generally accepted accounting principles in the United States of America, we met the criteria to classify our Argentina business unit as discontinued operations in the second quarter of 2014. As such, the results of operations for our Argentina business unit are reflected as loss from discontinued operations, net of income taxes and discussed further in Note 3, "Discontinued Operations," of our consolidated financial statements for the three years ended December 31, 2014.

On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera Petroleum Limited ("Petrolifera") pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera was a Calgary, Alberta, Canada based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru.

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

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

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

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America in Colombia, Peru and Brazil and we are headquartered in Calgary, Alberta, Canada.

On June 25, 2014, we 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. The decision to sell our Argentina business unit followed ongoing success in Colombia and ongoing evaluations in Brazil and was due to a decision to focus our human and capital resources in areas that we believe will provide the greatest return for our shareholders and drive growth in the future. In accordance with generally accepted accounting principles in the

United States of America ("GAAP"), we met the criteria to classify our Argentina business unit as discontinued operations in the second quarter of 2014. As such, the results of operations for our Argentina business unit are reflected as loss from discontinued operations, net of income taxes and discussed further in Note 3, "Discontinued Operations," of our consolidated financial statements for the three years ended December 31, 2014.

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.

For the year ended December 31, 2014, 95% (year ended December 31, 2013 - 96%; year ended December 31, 2012 - 98%) of our revenue and other income was generated in Colombia.

As of December 31, 2014, we had estimated proved reserves NAR of 37.0 MMBOE, approximately 100% oil, of which 79% were proved developed reserves. Our primary source of liquidity is cash generated from our operations and cash on hand.

The price of oil is a critical factor to our business, has historically been volatile, and has fallen dramatically in December 2014 and January 2015. Sustained periods of low oil prices could be detrimental to our financial performance. During 2014, the average price realized for our oil was $83.22 per barrel (2013 - $92.31; 2012 - $102.92). Average Brent oil prices for the year ended December 31, 2014, were $99.02 per bbl compared with $108.64 per bbl in 2013. West Texas Intermediate ("WTI") oil prices for the year ended December 31, 2014, were $93.00 per bbl compared with $97.97 per bbl in 2013. At the end of 2014, oil prices declined sharply, and the effect of that decline was not reflected in the average price for the year ended December 31, 2014. On December 31, 2014, the Brent oil price was $55.27 per bbl and the WTI oil price was $53.27 per bbl.

Business Strategy

We are focused on the South America oil and gas business with current operations in Colombia, Peru and Brazil. In today’s low commodity price environment we are taking prudent steps to ensure near term stability while positioning for growth in preparation for rising commodity prices in the future. A key piece in this strategy is the preservation of our strong balance sheet through reductions to our capital program, operating expenses, general and administrative costs and renegotiations of all service and transportation costs. For the capital program, only those projects that have immediate value additions or are contractual commitments will move forward, and all others will be deferred or canceled. Additionally, our exploration and development process is under review with the intent of high grading and enhancing our exploration success. The current process of prospect generation, selection, analysis and drilling decisions is under review. The exploration portfolio will be re-evaluated with a view to focusing on lower risk oil prospects and farming down higher risk longer term prospects. Whenever possible operatorship will be retained in order to maintain operational and financial control.

With a focus on cost control, we aim to continue to grow organically over the long-term, and, in the near-term, we look to leverage off our financial strength, South American experience and in-country relationships to grow inorganically through the opportunistic acquisition of distressed assets and/or companies in our target region which we believe will arise during this low commodity price cycle. We will also look to strategically dispose of non-core assets as opportunities to do so present themselves.

Highlights

	Year Ended December 31,				
	2014	% Change	2013	% Change	2012
Estimated Proved Oil and Gas Reserves, NAR, at December 31 (MMBOE) (5)	37.0	(12)	42.1	4	40.6
Estimated Probable Oil and Gas Reserves, NAR, at December 31 (MMBOE) (5) (6)	13.5	(81)	69.8	347	15.6
Estimated Possible Oil and Gas Reserves, NAR, at December 31 (MMBOE) (5) (6)	15.4	(79)	72.0	139	30.1
Production (BOEPD) (1) (2)	18,523	(4)	19,239	43	13,423
Prices Realized - per BOE (1)	$82.74	(10)	$92.13	(10)	$102.48
Revenue and Other Income ($000s) (1)	$562,254	(13)	$649,129	28	$505,176
(Loss) Income from Continuing Operations ($000s) (1)	$(144,349)	(180)	$181,023	81	$100,082
Loss from Discontinued Operations, Net of Income Taxes ($000s)	(26,990)	(51)	(54,735)	—	(423)
Net Income (Loss) ($000s)	$(171,339)	(236)	$126,288	27	$99,659
Income (Loss) Per Share - Basic					
(Loss) Income from Continuing Operations (1)	$(0.51)	(180)	$0.64	83	$0.35
Loss from Discontinued Operations, Net of Income Taxes	(0.09)	(53)	(0.19)	—	0.00
Net Income (Loss)	$(0.60)	(233)	$0.45	29	$0.35
Income (Loss) Per Share - Diluted					
(Loss) Income from Continuing Operations (1)	$(0.51)	(181)	$0.63	80	$0.35
Loss from Discontinued Operations, Net of Income Taxes	(0.09)	(53)	(0.19)	—	0.00
Net Income (Loss)	$(0.60)	(236)	$0.44	26	$0.35
Funds Flow From Continuing Operations ($000s) (1)(3)	$311,318	(9)	$343,199	17	$292,745
Net Capital Expenditures for Continuing Operations ($000s) (1) (4)	$416,232	41	$295,315	8	$272,523

	As at December 31,				
	2014	% Change	2013	% Change	2012
Cash & Cash Equivalents ($000s)	$331,848	(23)	$428,800	102	$212,624
Working Capital (including cash & cash equivalents) ($000s)	$239,824	(2)	$245,827	10	$222,468

Property, Plant & Equipment ($000s)	$1,128,944	(10)	$1,260,172	5	$1,205,426

(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes and losses, associated with discontinued operations was 1,361 BOEPD for the year ended December 31, 2014 (2013 - 3,028 BOEPD; 2012 - 3,474 BOEPD). Argentina production for the year ended December 31, 2014, was calculated to the date of sale of June 25, 2014.

(2) Production represents production volumes NAR adjusted for inventory changes and losses.

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

	Year Ended December 31,		
Funds Flow From Continuing Operations - Non-GAAP Measure ($000s)	2014	2013	2012
Net income (loss)	$(171,339)	$126,288	$99,659
Adjustments to reconcile net income (loss) to funds flow from continuing operations			
Loss from discontinued operations, net of income taxes	26,990	54,735	423
DD&A expenses	451,003	202,851	150,570
Deferred tax expense (recovery)	34,350	(28,865)	26,814
Non-cash stock-based compensation	5,451	8,002	10,999
Unrealized loss on financial instruments	9,383	—	—
Unrealized foreign exchange (gain) loss	(38,441)	(18,799)	17,150
Cash settlement of asset retirement obligation	(796)	(2,068)	—
Other loss	—	4,400	—
Other gain	(2,000)	—	(9,336)
Equity tax	(3,283)	(3,345)	(3,534)
Funds flow from continuing operations	$311,318	$343,199	$292,745

(4) In 2013, capital expenditures are net of proceeds of $54.0 million relating to termination of a farm-in agreement in Brazil; and $1.5 million relating to the sale of our 15% working interest in the Mecaya Block in Colombia.

(5) Estimated proved, probable and possible oil and gas reserves, NAR, as at December 31, 2013, included 4.4, 2.1 and 10.3 MMBOE, respectively, in Argentina. Estimated proved, probable and possible oil and gas reserves, NAR, as at December 31, 2012, included 6.3, 2.8 and 14.1 MMBOE, respectively, in Argentina.

(6) As previously discussed, 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 reserves are therefore excluded from this table.

- Oil and gas production NAR before inventory adjustments and losses increased to 19,283 BOEPD for the year ended December 31, 2014, compared with 19,071 BOEPD in 2013. In 2014, production from new wells in the Moqueta field in the Chaza Block and a new well in the Llanos-22 Block had a positive effect on production NAR before inventory adjustments and losses in Colombia, which was partially offset by the impact of well downtime for workovers and a water cut increase on the Costayaco field in the Chaza Block. Production in 2014 was 83% from the Chaza Block in Colombia.

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Oil and gas production, NAR and adjusted for inventory changes and losses, decreased by 4% to 18,523 BOEPD for the year ended December 31, 2014, compared with 19,239 BOEPD in 2013. During the year ended December 31, 2014, an oil inventory and losses ("oil inventory") increase accounted for 0.3 MMbbl or 760 bopd of reduced production compared with an oil inventory decrease in 2013 which accounted for 0.1 MMbbl or 168 bopd increased production.

- Estimated proved oil and NGL reserves, NAR, as of December 31, 2014, were 36.9 MMbbl, compared with 39.8 MMbbl as at December 31, 2013, and after 2014 oil and NGL production of 7.0 MMbbl NAR before inventory changes and losses, excluding Argentina production. The decrease was primarily due to the sale of our Argentina business unit during 2014 which contributed 3.6 MMbbl of proved oil and NGL reserves, NAR, as at December 31, 2013. This was partially offset by: reserve additions in Colombia for the Costayaco field due to reservoir performance and additional development drilling; reserve additions in Colombia for the Moqueta field due to delineation drilling; and reserve additions in Brazil for the Tiê field due to a successful dual completion program, the acid stimulation treatment of the Agua Grande formation, results of seismic reprocessing, and additional reservoir volume in the Sergi formation,

- Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2014, were 13.0 MMbbl and 14.9 MMbbl, respectively, compared with 68.9 MMbbl and 63.7 MMbbl as of December 31, 2013. As previously discussed, all probable and possible reserves associated with the Bretaña field on Block 95 in Peru were reclassified as contingent resources in a report with an effective date of January 31, 2015, as a result of 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 December 31, 2014, reserves referred to in this bullet exclude probable and possible reserves associated with the Bretaña field. Estimated probable and possible oil and NGL reserves, NAR, as at December 31, 2013, included 1.8 and 2.6 MMbbl, respectively, in Argentina. The December 31, 2013, reserves also included 57.6 MMBOE and 104.7 MMBOE of 2P and 3P reserves relating to the Bretaña Field on Block 95 in Peru.

- Estimated proved gas reserves, NAR, as of December 31, 2014, were 1.0 Bcf compared with 13.5 Bcf at December 31, 2013. Estimated probable and possible gas reserves, NAR, as of December 31, 2014 were 3.4 Bcf and 2.5 Bcf, respectively, compared with 5.5 Bcf and 50.3 Bcf as of December 31, 2013. Estimated proved, probable and possible gas reserves in Argentina, NAR, as at December 31, 2013, were 4.7 Bcf, 1.7 Bcf and 46.2 Bcf, respectively.

- For the year ended December 31, 2014, revenue and other income decreased by 13% to $562.3 million compared with $649.1 million in 2013. The decrease was due to the combined effect of decreased production and lower realized prices. The average price realized per BOE decreased by 10% to $82.74 from $92.13 in 2013.

- Loss from continuing operations for the year ended December 31, 2014, was $144.3 million, or $0.51 per share basic and diluted, compared with income from continuing operations of $181.0 million, or $0.64 per share basic and $0.63 per share diluted, in 2013. In the year ended December 31, 2014, we recorded an impairment loss of $265.1 million in our Peru cost center relating to costs incurred on Block 95.

- Loss from discontinued operations, net of income taxes, was $27.0 million, or $0.09 per share basic and diluted for the year ended December 31, 2014, compared with $54.7 million, or $0.19 per share basic and diluted, in 2013. Loss from discontinued operations after income taxes for the year ended December 31, 2013, included a ceiling test impairment loss of $30.8 million in our Argentina cost center due to a decrease in reserves as a result of deferred investment and inconclusive waterflood results on the Puesto Morales Block. For the year ended December 31, 2014, loss from discontinued operations, net of tax, included loss on disposal of the Argentina business unit of $19.3 million.

- Loss for the year ended December 31, 2014, was $171.3 million, or $0.60 per share basic and diluted, compared with net income of $126.3 million, or $0.45 per share basic and $0.44 per share diluted, in 2013. As previously discussed, in the year ended December 31, 2014, we recorded an impairment loss of $265.1 million in our Peru cost center relating to costs incurred on Block 95. Additionally, the decrease was due to lower income from continuing operations and the recognition of a loss on sale of the Argentina business unit, partially offset by the effect of the ceiling test impairment loss of $30.8 million in our Argentina cost center in 2013.

- For the year ended December 31, 2014, funds flow from continuing operations decreased by 9% from $343.2 million to $311.3 million primarily due to decreased oil and natural gas sales and increased operating and G&A expenses, partially offset by realized foreign exchange and financial instrument gains and lower income tax expenses.

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Cash and cash equivalents were $331.8 million at December 31, 2014, compared with $428.8 million at December 31, 2013. The decrease in cash and cash equivalents for the year ended December 31, 2014, was primarily the result of cash capital expenditures of $347.0 million, cash used in operating activities of discontinued operations of $4.8 million and $97.9 million change in assets and liabilities from operating activities of continuing operations, partially offset by funds flow from continuing operations of $311.3 million, cash provided by investing activities of discontinued operations of $30.4 million, and proceeds from the issuance of shares of common stock of $11.1 million.

- Working capital (including cash and cash equivalents) was $239.8 million at December 31, 2014, a $6.0 million decrease from December 31, 2013.

- Property, plant and equipment ("PPE") at December 31, 2014, was $1.1 billion, a decrease of $131.2 million from December 31, 2013, as a result of $416.2 million of capital expenditures related to continuing operations and $18.7 million of capital expenditures related to discontinued operations, partially offset by the sale of the Argentina business unit PPE of

$100.2 million, $453.0 million of depletion, depreciation and impairment expenses related to continuing operations, including an impairment loss of $265.1 million in our Peru cost center relating to costs incurred on Block 95, and $12.9 million of depletion, depreciation and impairment expenses recorded in loss from discontinued operations.

- Capital expenditures for the year ended December 31, 2014 for continuing operations, were $416.2 million compared with $295.3 million for the year ended December 31, 2013. In 2014, capital expenditures included drilling of $245.3 million, geological and geophysical ("G&G") expenditures of $96.1 million, facilities of $36.6 million and other expenditures of $38.2 million.

Estimated Oil and Gas Reserves

As at December 31, 2014, estimated proved oil and gas reserves, NAR, were 37.0 MMBOE compared with 42.1 MMBOE as at December 31, 2013 and 40.6 MMBOE as at December 31, 2012. Proved reserves at December 31, 2014 were after 2014 oil and gas production of 7.0 MMBOE NAR before inventory changes and losses. Estimated proved oil and gas reserves, NAR, as at December 31, 2013, included 4.4 MMBOE in Argentina. We sold our Argentina business unit during 2014.

Estimated proved oil reserves, NAR, as of December 31, 2014, were 36.9 MMbbl compared with 39.8 MMbbl as at December 31, 2013 and after producing 7.0 MMbbl NAR before inventory adjustments and losses, excluding Argentina production. The decrease was primarily due to the sale of our Argentina business unit during 2014 which contributed 3.6 MMbbl of proved oil and NGL reserves at December 31, 2013. This was partially offset by: reserve additions in Colombia for the Costayaco field due to reservoir performance and additional development drilling; reserve additions in Colombia for the Moqueta field due to delineation drilling; and reserve additions in Brazil for the Tiê field due to a successful dual completion program and the acid stimulation treatment of the Agua Grande formation.

Estimated probable and possible oil reserves, NAR, as of December 31, 2014 were 13.0 MMbbl and 14.9 MMbbl, respectively, compared with 68.9 MMbbl and 63.7 MMbbl as of December 31, 2013. As previously discussed, all probable and possible reserves associated with the Bretaña field on Block 95 in Peru were reclassified as contingent resources in a report with an effective date of January 31, 2015, as a result of 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 December 31, 2014, reserves referred to in this paragraph exclude probable and possible reserves associated with the Bretaña field. Estimated probable and possible oil and NGL reserves, NAR, as at December 31, 2013, included 1.8 and 2.6 MMbbl, respectively, in Argentina. The December 31, 2013, reserves also included 57.6 MMBOE and 104.7 MMBOE of 2P and 3P reserves relating to the Bretaña Field on Block 95 in Peru. Estimated proved, probable and possible oil reserves, included small amounts of NGL reserves at December 31, 2013, and 2012.

Estimated proved gas reserves, NAR, as of December 31, 2014, were 1.0 Bcf compared with 13.5 Bcf at December 31, 2013. Estimated probable and possible gas reserves, NAR, as of December 31, 2014, were 3.4 Bcf and 2.5 Bcf, respectively, compared with 5.5 Bcf and 50.3 Bcf as of December 31, 2013. Estimated proved, probable and possible gas reserves in Argentina, NAR, as at December 31, 2013, were 4.7 Bcf, 1.7 Bcf and 46.2 Bcf, respectively.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2013, were 39.8 MMbbl, a 4% increase from estimated proved reserves as at December 31, 2012. The increase was due primarily to positive technical adjustments for the Costayaco field due to reservoir performance, additional development drilling in the Costayaco field and the appraisal drilling program in the Moqueta field. Reserves were also added for the Tiê field in the Recôncavo Basin, Brazil due to production performance.

Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2013 were 68.9 MMbbl and 63.7 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2013, were 13.5 Bcf compared with 12.8 Bcf at December 31, 2012. Proved gas reserves were consistent with the prior year end as new gas reserves were developed to replace 2013 production. Estimated probable and possible gas reserves, NAR, as of December 31, 2013 were 5.5 Bcf and 50.3 Bcf, respectively.

Business Environment Outlook

Our revenues are significantly affected by pipeline disruptions in Colombia and the continuing fluctuations in oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about the quantity of world supply and demand, market competition between large suppliers to the market for market share, political influences, financial markets and the impact of the worldwide economy on oil supply and demand growth.

We believe that our current operations and 2015 capital expenditure program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including additional pipeline delivery restrictions in Colombia or a protracted downturn in oil and gas prices, we would examine measures such as further capital expenditure program reductions, use of our revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. Given the current economic environment and unstable conditions in the Middle East, North Africa, and Eastern Europe and the current over supply of oil in world markets, the oil price environment is unpredictable and unstable. We are unable to determine the impact, if any, these events may have on oil prices and demand. The timing and execution of our capital expenditure program are also affected by the availability of services from third party oil field contractors and our ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities. Any delay may affect our ability to execute our capital expenditure program.

The credit markets, including the high yield bond market and other debt markets that provide capital to oil and gas companies have experienced adverse conditions. We have not been materially impacted by these conditions; however, continuing volatility in oil prices may continue to contribute to these adverse conditions, which could increase costs associated with renewing or issuing debt or affect our ability to access those markets.

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

Business Combinations

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

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

Consolidated Results of Operations

	Year Ended December 31,				
	2014	% Change	2013	% Change	2012
(Thousands of U.S. Dollars)					
Oil and natural gas sales (1)	$559,398	(14)	$646,955	28	$503,467
Interest income (1)	2,856	31	2,174	27	1,709
	562,254	(13)	649,129	28	505,176
Operating expenses (1)	113,949	3	110,172	19	92,207
DD&A expenses (1)	451,003	122	202,851	35	150,570
G&A expenses (1)	51,249	25	41,115	(12)	46,659
Financial instruments loss (1)	4,722	—	—	—	—
Other loss (1)	—	(100)	4,400	—	—
Other gain (1)	(2,000)	—	—	(100)	(9,336)
Foreign exchange (gain) loss (1)	(39,535)	111	(18,693)	(165)	28,727
	579,388	70	339,845	10	308,827
(Loss) income from continuing operations before income taxes (1)	(17,134)	(106)	309,284	58	196,349
Income tax expense (1)	(127,215)	(1)	(128,261)	33	(96,267)
(Loss) income from continuing operations (1)	(144,349)	(180)	181,023	81	100,082
Loss from discontinued operations, net of income taxes	(26,990)	(51)	(54,735)	—	(423)
Net income (loss)	$(171,339)	(236)	$126,288	27	$99,659
Production (1) (2)					
Oil and NGL's, bbl	6,706,083	(4)	7,006,657	43	4,886,842
Natural gas, Mcf	329,312	254	92,942	(40)	154,702
Total production, BOE	6,760,968	(4)	7,022,147	43	4,912,626
Average Prices (1)					
Oil and NGL's per bbl	$83.22	(10)	$92.31	(10)	$102.92
Natural gas per Mcf	$4.52	24	$3.64	15	$3.16
Consolidated Results of Operations per BOE (1)					
Oil and natural gas sales	$82.74	(10)	$92.13	(10)	$102.48
Interest income	0.42	35	0.31	(11)	0.35
	83.16	(10)	92.44	(10)	102.83
Operating expenses	16.85	7	15.69	(16)	18.77
DD&A expenses	66.71	131	28.89	(6)	30.65
G&A expenses	7.58	29	5.86	(38)	9.50
Financial instruments loss	0.70	—	—	—	—
Other loss	—	(100)	0.63	—	—

Other gain	(0.30	)	—		—	(100	)	(1.90)
Foreign exchange (gain) loss	(5.85	)	120		(2.66	) (145	)	5.85
	85.69		77		48.41	(23	)	62.87
(Loss) income from continuing operations before income taxes	(2.53	)	(106	)	44.03	10		39.96
Income tax expense	(18.82)		3		(18.27)	(7	)	(19.60)
(Loss) income from continuing operations	$(21.35	)	(183	)	$25.76	27		$20.36

(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes and losses, associated with discontinued operations was 1,361 BOEPD for the year ended December 31, 2014 (2013 - 3,028

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BOEPD; 2012 - 3,474 BOEPD). Argentina production for the year ended December 31, 2014, was calculated to the date of sale of June 25, 2014.

(2) Production represents production volumes NAR adjusted for inventory changes and losses.

Consolidated Results of Continuing Operations for the Year Ended December 31, 2014, Compared with the Results for the Year Ended December 31, 2013

Loss for the year ended December 31, 2014, was $171.3 million, or $0.60 per share basic and diluted, compared with net income of $126.3 million, or $0.45 per share basic and $0.44 per share diluted, in 2013. In the year ended December 31, 2014, we recorded an impairment loss of $265.1 million in our Peru cost center, as previously discussed. In the year ended December 31, 2014, lower income from continuing operations and the recognition of a loss on sale of the Argentina business unit were partially offset by the effect of the ceiling test impairment loss of $30.8 million in our Argentina cost center in 2013.

Loss from continuing operations for the year ended December 31, 2014, was $144.3 million, or $0.51 per share basic and diluted, compared with income from continuing operations of $181.0 million, or $0.64 per share basic and $0.63 per share diluted, in 2013. For the year ended December 31, 2014, decreased oil and natural gas sales as a result of lower realized oil prices and production after inventory changes and losses, increased operating, DD&A and G&A expenses and financial instrument losses were only partially offset by higher foreign exchange and other gains, the absence of other loss recorded in 2013 and lower income tax expenses.

Loss from discontinued operations, net of income taxes for the year ended December 31, 2014, was $27.0 million, or $0.09 per share basic and diluted, compared with $54.7 million, or $0.19 per share basic and diluted in 2013. Loss from discontinued operations before income taxes in Argentina for the year ended December 31, 2013, included a ceiling test impairment loss of $30.8 million in our Argentina cost center due to a decrease in reserves as a result of deferred investment and inconclusive waterflood results on the Puesto Morales Block. For the year ended December 31, 2014, loss from discontinued operations, net of tax, included loss on disposal of the Argentina business unit of $19.3 million.

Oil and NGL production NAR before inventory adjustments and losses for the year ended December 31, 2014, increased to 19,133 bopd compared with 19,034 bopd in 2013. In 2014, production from new wells in the Moqueta field in the Chaza Block and a new well in the Llanos-22 Block had a positive effect on production NAR before inventory adjustments and losses in Colombia, which was partially offset by the impact of well downtime for workovers and a water cut increase at the Costayaco field in the Chaza Block.

Oil and NGL production NAR after inventory adjustments and losses for the year ended December 31, 2014, decreased by 4% to 18,373 bopd compared with 19,196 bopd in 2013. During the year ended December 31, 2014, an oil inventory increase accounted for 0.3 MMbbl or 760 bopd of reduced production compared with an oil inventory decrease in 2013 which accounted for 0.1 MMbbl or 162 bopd increased production. During the years ended December 31, 2014, and 2013, the impact of Ecopetrol S.A. ("Ecopetrol") operated Trans-Andean oil pipeline (the "OTA pipeline") disruptions on production was partially mitigated by selling a portion of our oil through trucking and use of alternative pipelines.

Average realized oil prices decreased by 10% to $83.22 per bbl for the year ended December 31, 2014, from $92.31 per bbl for 2013 primarily due to decreases in the benchmark prices during the year. Average Brent oil prices for the year ended December 31, 2014, were $99.02 per bbl compared with $108.64 per bbl in 2013. West Texas Intermediate ("WTI") oil prices for the year ended December 31, 2014, were $93.00 per bbl compared with $97.97 per bbl in 2013.

During the fourth quarter of 2012, we commenced sales using transportation alternatives during periods of OTA pipeline disruptions. During the year ended December 31, 2014, 52% of our oil and gas volumes sold in Colombia, were through these transportation alternatives, compared with 64% in 2013. These sales have varying affects on our realized prices and transportation costs.

Beginning July 1, 2014, the port operations fee component of the OTA pipeline pricing structure increased by $2.94 per bbl resulting in a reduction of realized oil prices by this amount on sales delivered through the OTA pipeline.

Revenue and other income for the year ended December 31, 2014, decreased to $562.3 million from $649.1 million in 2013 as a result of the combined effect of decreased production and realized prices.

Operating expenses for the year ended December 31, 2014, increased by 3% to $113.9 million compared with $110.2 million in 2013. The effect of decreased production was more than offset by increased operating costs per BOE. On a per BOE basis, operating expenses increased by 7% to $16.85 from $15.69 in 2013. The increase in operating expenses per BOE in 2014 was primarily due to higher transportation costs associated with higher sales using the OTA pipeline which carried higher transportation costs instead of the realized price reductions that we incur with some alternative customers, and increased workover expenses.

DD&A expenses for the year ended December 31, 2014, increased to $451.0 million from $202.9 million in 2013. As previously discussed, DD&A expenses in the year ended December 31, 2014, included $265.1 million of impairment charges in our Peru cost center, whereas DD&A expenses in 2013 included a $2.0 million ceiling test impairment in our Brazil cost center. On a per BOE basis, the depletion rate increased by 131% to $66.71 from $28.89. On a per BOE basis, the increase was due to an increase in the impairment charge and increases in costs in the depletable base, partially offset by increased reserves.

G&A expenses for the year ended December 31, 2014, of $51.2 million increased by 25% from $41.1 million in 2013. The increase was primarily associated with increased activity for expanded operations in Peru, increased salary expenses and higher consulting expenses. G&A expenses per BOE in the year ended December 31, 2014, of $7.58 were 29% higher compared with $5.86 in 2013 for the same reasons as well as lower production.

Financial instruments loss was $4.7 million for the year ended December 31, 2014, comprising unrealized financial instruments losses of $9.4 million and realized financial instrument gains of $4.7 million.

Financial instrument loss for the year ended December 31, 2014, included a $6.3 million unrealized loss on the Madalena shares we received in connection with the sale of our Argentina business unit. Madalena is an independent, Canadian-based, domestic and international upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Madalena's shares are listed on the Canadian TSX Venture Exchange.

Financial instruments loss for the year ended December 31, 2014, also included a $1.6 million gain, comprising a $4.7 million realized gain and $3.1 million unrealized losses, on our Colombian peso non-deliverable forward contracts. We purchased these contracts for purposes of fixing the exchange rate at which we will purchase or sell Colombian pesos to settle our income tax installments and payments.

Other loss in the year ended December 31, 2013, related to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment in 2013. The amount awarded in the legal judgment was denominated in bbl of oil. We filed an appeal against the judgment.

Other gain in the year ended December 31, 2014, related to a reduction in the value of the contingent loss referred to above, due to lower oil prices.

For the year ended December 31, 2014, the foreign exchange gain was $39.5 million, of which $38.4 million was an unrealized non-cash foreign exchange gain. For the year ended December 31, 2013, the foreign exchange gain was $18.7 million, of which $18.8 million was an unrealized non-cash foreign exchange gain. The unrealized foreign exchange gains in 2014 and 2013 were a result of a net monetary liability position in Colombia combined with the weakening of the Colombian peso.

Income tax expense related to continuing operations was $127.2 million for the year ended December 31, 2014, compared with $128.3 million in 2013. The decrease was primarily due to lower taxable income in Colombia and lower taxes in Brazil, partially offset by the impact of future tax rate changes on the Colombian deferred tax liability. In 2013 in Brazil, a net payment of $54.0 million from a third party in connection with the termination of a farm-in agreement resulted in a current tax expense of approximately $10.4 million. In 2014, tax legislation was enacted in

Colombia which increased the 2015 to 2018 tax rates resulting in an increase of the Colombian deferred tax liability of approximately $31.0 million.

In the year ended December 31, 2014, we had income tax expense despite having loss from continuing operations, compared with an effective tax rate of 41% in 2013. For the year ended December 31, 2014, the difference between the effective tax rate and the 35% U.S. statutory rate was primarily a result of a loss before income taxes caused by the 2014 impairment loss in Peru which was fully offset by an increase in the valuation allowance. Other factors that affected the effective tax rate in 2014 were the change in the Colombian future tax rate, a non-deductible third party royalty in Colombia, the impact of other local taxes, and stock-based compensation, partially offset by foreign currency translation adjustments and other permanent differences. The variance from the 35% U.S. statutory rate for the year ended December 31, 2013, was primarily attributable to an increase in the valuation allowance, a non-deductible third party royalty in Colombia, the impact of local taxes, and stock-based compensation, partially offset by other permanent differences, foreign currency translation adjustments and the foreign tax rate differential.

Consolidated Results of Continuing Operations for the Year Ended December 31, 2013, Compared with the Results for the Year Ended December 31, 2012

Net income for the year ended December 31, 2013, was $126.3 million, a 27% increase from 2012. On a per share basis, net income increased to $0.45 per share basic and $0.44 diluted from $0.35 per share basic and diluted in 2012. The increase was due to higher income from continuing operations, partially offset by the effect of the ceiling test impairment loss of $30.8 million in discontinued operations relating to our Argentina cost center, in 2013.

Income from continuing operations for the year ended December 31, 2013, was $181.0 million, or $0.64 per share basic and $0.63 per share diluted, compared with $100.1 million, or $0.35 per share basic and diluted in 2012. For the year ended December 31, 2013, increased oil and natural gas sales, lower G&A expenses and foreign exchange gains were partially offset by increased operating, DD&A and income tax expenses, other loss and the absence of other gain recorded in 2012.

Loss from discontinued operations, net of income taxes for the year ended December 31, 2013 was $54.7 million, or $0.19 per share basic and diluted, compared with $0.4 million, or $0.00 per share basic and diluted in 2012. Loss from discontinued operations before income taxes for the year ended December 31, 2013, included a ceiling test impairment loss of $30.8 million in our Argentina cost center due to a decrease in reserves as a result of deferred investment and inconclusive waterflood results on the Puesto Morales Block. Additionally, oil and natural gas sales in Argentina decreased and operating expenses and foreign exchange losses increased in 2013 compared with 2012.

Oil and NGL production NAR before inventory adjustments and losses for the year ended December 31, 2013, increased to 19,034 bopd compared with 14,500 bopd in 2012 due to the reduced impact of pipeline disruptions in Colombia and production from new wells in Colombia. In the year ended December 31, 2013, the impact of OTA pipeline disruptions on production was mitigated by selling a portion of our oil through trucking and an alternative pipeline.

Oil and NGL production NAR after inventory adjustments and losses for the year ended December 31, 2013, increased by 43% to 19,196 bopd compared with 13,352 bopd in 2012. During the year ended December 31, 2013, an oil inventory decrease in 2013 accounted for 0.1 MMbbl or 162 bopd of increased production compared with an oil inventory increase in 2012 which accounted for 0.3 MMbbl or 1,148 bopd of reduced production.

Average realized oil prices decreased by 10% to $92.31 per bbl for the year ended December 31, 2013, from $102.92 per bbl for 2012. Average Brent oil prices for the year ended December 31, 2013, were $108.64 per bbl compared with $111.67 per bbl in 2012. WTI oil prices for the year ended December 31, 2013, were $97.97 per bbl compared with $94.20 per bbl in 2012. During the year ended December 31, 2013, 49% of our oil and gas volumes sold in Colombia were to a customer which takes delivery at the Costayaco battery and transports the oil by truck over a 1,500 km route to the Port of Barranquilla. The sales price for this customer is based on average WTI prices plus a Vasconia differential and premium, less trucking costs. For sales to this customer, the trucking costs are recorded as a reduction of the realized price and not as operating costs.

Revenue and other income for the year ended December 31, 2013, increased to $649.1 million from $505.2 million in 2012 as a result of increased production, partially offset by decreased realized prices.

Operating expenses for the year ended December 31, 2013, were $110.2 million, or $15.69 per BOE, compared with $92.2 million, or $18.77 per BOE, in 2012. For the year ended December 31, 2013, a decrease in the operating cost per BOE was more than offset by increased production. Operating expenses per BOE decreased in 2013 primarily due to OTA transportation costs and other trucking costs not incurred for those volumes subject to alternative transportation arrangements, whereby trucking costs are netted to arrive at our realized price.

DD&A expenses for the year ended December 31, 2013, increased to $202.9 million from $150.6 million in 2012. DD&A expenses for the year ended December 31, 2013, included a $2.0 million ceiling test impairment loss in our Brazil cost center. DD&A expenses in 2012 included a $20.2 million ceiling test impairment in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. On a per BOE basis, the depletion rate decreased by 6% to $28.89 from $30.65. Lower impairment losses and increased proved reserves, were only partially offset by increased costs in the depletable base.

G&A expenses for the year ended December 31, 2013, of $41.1 million decreased by 12% from $46.7 million in 2012. Increased employee related costs reflecting expanded operations were more than offset by higher G&A allocations to operating expenses and capital projects within the business units. G&A expenses per BOE in the year ended December 31, 2013, of $5.86

were 38% lower compared with $9.50 in 2012 due to increased production and higher G&A allocations to operating expenses and capital projects within the business units.

Other loss in the year ended December 31, 2013, relates to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment in the first quarter of 2013. We have filed an appeal against the judgment.

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

For the year ended December 31, 2013, the foreign exchange gain was $18.7 million, of which $18.8 million was an unrealized non-cash foreign exchange gain. The unrealized foreign exchange gain in 2013 was a result of a net monetary liability position in Colombia combined with the weakening of the Colombian peso. For the year ended December 31, 2012, the foreign exchange loss was $28.7 million, of which $17.1 million was an unrealized non-cash foreign exchange loss. Furthermore, in 2012, we had a realized foreign exchange loss of $11.6 million which primarily arose upon payment of 2011 Colombian income tax liabilities. The Colombian peso weakened by 9.0% and strengthened by 8.3% against the U.S. dollar in the years ended December 31, 2013 and 2012, respectively.

Income tax expense was $128.3 million for the year ended December 31, 2013, compared with $96.3 million in 2012. The increase was primarily due to higher taxable income in Colombia and Brazil. In Brazil, a net payment of $54.0 million from a third party in connection with the termination of a farm-in agreement resulted in a current tax expense of approximately $10.4 million during the third quarter of 2013. The effective tax rate was 41% in the year ended December 31, 2013, compared with 49% in 2012. The change in the effective tax rate from 2012 was primarily due to a decrease in non-deductible foreign currency translation adjustments and other permanent differences offset partially by an increase in the valuation allowance.

For 2013, the differential between the effective tax rate of 41% and the 35% U.S. statutory rate was primarily attributable to the increase in valuation allowance and a non-deductible third party royalty in Colombia, which were partially offset by a reduction in non-deductible foreign currency translation adjustments and other permanent differences. The variance from the 35% U.S. statutory rate for 2012 was primarily attributable to a non-deductible third party royalty in Colombia, non-deductible foreign currency translation adjustments and other permanent differences.

2015 Capital Program

On February 8, 2015, we announced a revised preliminary 2015 capital program. This revised capital program is designed to retain balance sheet strength by minimizing or deferring expenditures given the current oil price environment.

We reduced our capital program for 2015 to $140 million. This is a reduction of $170 million from the previously announced capital program of $310 million. The revised preliminary capital program for operations in Colombia, Peru and Brazil allocates $50 million for drilling, $41 million for facilities, pipelines and other; and $49 million for G&G expenditures. Of the $140 million approximately $43 million had already been spent or committed. Approximately $37 million of the capital program is dedicated to the maintenance of existing production while $24 million is dedicated to drilling in Colombia.

We expect to finance our 2015 revised capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds be expended as set forth in our 2015 revised preliminary capital program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Segmented Results from Continuing Operations – Colombia

	Year Ended December 31, 2014	% Change	2013	% Change	2012
(Thousands of U.S. Dollars)					
Oil and natural gas sales	$532,196	(15)	$624,410	26	$493,615
Interest income	569	(9)	623	(7)	667
	532,765	(15)	625,033	26	494,282
Operating expenses	107,101	4	102,861	18	87,410
DD&A expenses	174,063	(6)	184,697	51	122,055
G&A expenses	19,431	14	16,996	(26)	23,019
Financial instruments gain	(1,605)	—	—	—	—
Other loss	—	(100)	4,400	—	—
Other gain	(2,000)	—	—	(100)	(9,336)
Foreign exchange (gain) loss	(44,149)	120	(20,100)	(175)	26,660
	252,841	(12)	288,854	16	249,808
Income from continuing operations before income taxes	$279,924	(17)	$336,179	38	$244,474
Production (1)					
Oil and NGL's, bbl	6,376,048	(6)	6,767,617	41	4,785,643
Natural gas, Mcf	329,312	254	92,942	(40)	154,702
Total production, BOE	6,430,933	(5)	6,783,107	41	4,811,427
Average Prices					
Oil and NGL's per bbl	$83.23	(10)	$92.21	(11)	$103.04
Natural gas per Mcf	$4.52	24	$3.64	15	$3.16
Segmented Results of Operations per BOE					
Oil and natural gas sales	$82.76	(10)	$92.05	(10)	$102.59
Interest income	0.09	—	0.09	(36)	0.14
	82.85	(10)	92.14	(10)	102.73
Operating expenses	16.65	10	15.16	(17)	18.17
DD&A expenses	27.07	(1)	27.23	7	25.37
G&A expenses	3.02	20	2.51	(47)	4.78
Financial instruments gain	(0.25)	—	—	—	—
Other loss	—	(100)	0.65	—	—
Other gain	(0.31)	—	—	(100)	(1.94)
Foreign exchange (gain) loss	(6.87)	132	(2.96)	(153)	5.54
	39.31	(8)	42.59	(18)	51.92
Income from continuing operations before income taxes	$43.54	(12)	$49.55	(2)	$50.81

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

Segmented Results of Continuing Operations - Colombia for the Year Ended December 31, 2014, Compared with the Results for the Year Ended December 31, 2013

For the year ended December 31, 2014, income from continuing operations before income taxes was $279.9 million compared with $336.2 million in 2013. The decrease was due to lower oil and natural gas sales and higher operating and G&A expenses, partially offset by decreased DD&A expenses, financial instrument and other gains, the absence of other losses recorded in 2013 and higher foreign exchange gains.

Oil and NGL production NAR before inventory adjustments and losses for the year ended December 31, 2014, decreased to 18,229 bopd compared with 18,313 bopd in 2013. In 2014, production from new wells in the Moqueta field in the Chaza Block and a new well in the Llanos-22 Block had a positive effect on production NAR before inventory adjustments and losses, which was more than offset by the impact of well downtime for workovers and a water cut increase at the Costayaco field in the Chaza Block. Production during the year ended December 31, 2014, reflected 180 days of oil delivery restrictions in Colombia, compared with 229 days of oil delivery restrictions in 2013.

Oil and NGL production NAR after inventory adjustments and losses for the year ended December 31, 2014, decreased to 6.4 MMbbl or 17,469 bopd compared with 6.8 MMbbl or 18,541 bopd in 2013. During the year ended December 31, 2014, an oil inventory increase accounted for decreased production of 0.3 MMbbl or 760 bopd compared with an oil inventory decrease in 2013 which accounted for 0.1 MMbbl or 228 bopd increased production.

In the year ended December 31, 2014, our oil inventory increased due to the timing of revenue recognition for deliveries to a customer with a protracted sales cycle and oil inventory in the OTA pipeline and associated Ecopetrol owned facilities. In addition, the inventory in our tanks in the Putumayo Basin increased primarily as a result of normal OTA pipeline operations in December 2014. The oil inventory reduction in the year ended December 31, 2013, was due to a decrease in oil inventory in the OTA pipeline and associated Ecopetrol owned facilities in the Putumayo Basin and lower inventory at other customers' facilities. At the beginning of 2013, oil inventory at customer's facilities was higher due to deliveries made in 2012 to a short-term customer with a protracted sales cycle whereby the transfer of ownership occurred upon export.

Revenue and other income decreased by 15% to $532.8 million for the year ended December 31, 2014, compared with $625.0 million in 2013.

For the year ended December 31, 2014, the average realized price per bbl for oil decreased by 10% to $83.23 compared with $92.21 in 2013, primarily due to decreases in benchmark prices. Average Brent oil prices for the year ended December 31, 2014, were $99.02 per bbl compared with $108.64 per bbl in 2013.

During the fourth quarter of 2012, we commenced sales using transportation alternatives during periods of OTA pipeline disruptions. These sales have varying affects on our realized prices and transportation costs. During the year ended December 31, 2014, 52% of our oil and gas volumes sold in Colombia were through these transportation alternatives. The effect on the Colombian realized price for the year ended December 31, 2014, for sales using these transportation alternatives was a reduction of approximately $2.02 per BOE, compared with delivering all of our Colombian oil through the OTA pipeline. Sales using these transportation alternatives during 2013 were 64% of our oil and gas volumes sold in Colombia and the effect on the Colombian realized price was a reduction of approximately $9.68. Additionally, an increase in the Port of Tumaco tariff effective July 1, 2014, reduced our realized Colombia oil price by approximately $0.73 per bbl in the year ended December 31, 2014.

Operating expenses increased by 4% to $107.1 million for the year ended December 31, 2014, from $102.9 million in 2013. The effect of decreased production was more than offset by increased operating costs per BOE. On a per BOE basis, operating expenses increased by 10% to $16.65 for the year ended December 31, 2014, from $15.16 in 2013. Operating costs per BOE increased primarily due to higher transportation costs associated with higher sales using the OTA pipeline which carried higher transportation costs instead of the realized price reductions that we incur with some alternative customers, partially offset by the effect of liquidated inventory volumes in 2013. Additionally, in the year ended December 31, 2014, workover expenses increased by $0.51 per BOE compared with 2013. The inventory volumes liquidated in 2013, were primarily related to a delivery point which carried high transportation costs and to which we did not deliver in 2014. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the year ended December 31, 2014, was a saving of $0.44 per BOE compared with a saving of $1.57 in 2013.

DD&A expenses decreased by 6% to $174.1 million for the year ended December 31, 2014, from $184.7 million in 2013. The decrease was primarily due to decreased production. On a per BOE basis, DD&A expenses decreased by 1% to $27.07 as a result of increased costs in the depletable base being more than offset by an increase in reserves.

For the year ended December 31, 2014, G&A expenses increased by 14% to $19.4 million ($3.02 per BOE) from $17.0 million ($2.51 per BOE) in 2013. The increase was primarily due to increased salaries expense and an increased headcount.

Financial instruments gain of $1.6 million in the year ended December 31, 2014, related to gains on our Colombian peso non-deliverable forward contracts, of which a $4.7 million gain was realized during the year ended December 31, 2014. We purchased these contracts for purposes of fixing the exchange rate at which we purchase or sell Colombian pesos to settle our income tax installments and payments.

Other loss in the year ended December 31, 2013, related to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment in 2013. The amount awarded in the legal judgment was denominated in barrels of oil. We filed an appeal against the judgment.

Other gain in the year ended December 31, 2014, related to a reduction in the value of the contingent loss referred to above due to lower oil prices.

For the year ended December 31, 2014, the foreign exchange gain was $44.1 million, of which $39.7 million was an unrealized non-cash foreign exchange gain. In the year ended December 31, 2013, we incurred a foreign exchange gain of $20.1 million of which $18.8 million was an unrealized non-cash foreign exchange gain. The Colombian peso weakened by 24% against the U.S. dollar in the year ended December 31, 2014, and by 9% against the U.S. dollar in the year ended December 31, 2013. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation is the main source of the unrealized foreign exchange losses or gains.

Segmented Results of Continuing Operations - Colombia for the Year Ended December 31, 2013, Compared with the Results for the Year Ended December 31, 2012

For the year ended December 31, 2013, income from continuing operations before income taxes was $336.2 million compared with $244.5 million in 2012. The increase was due to higher oil and natural gas sales as a result of increased production, decreased G&A expenses and higher foreign exchange gains, partially offset by increased operating and DD&A expenses, other loss and the absence of a gain relating to the recovery of value added tax in 2012.

Oil and NGL production, NAR and adjusted for inventory changes and losses, for the year ended December 31, 2013, increased to 6.8 MMbbl or 18,541 bopd compared with 4.8 MMbbl or 13,076 bopd for 2012 due to the reduced impact of pipeline disruptions, a decrease in oil inventory and increased production from new wells in the Costayaco and Moqueta fields in the Chaza Block and long-term test production from a new well on the Llanos-22 Block. In 2013, the net inventory decrease accounted for 0.1 MMbbl or 228 bopd of the production increase compared with a net inventory increase which accounted for 0.4 MMbbl or 1,132 bopd of the production decrease in 2012. Production during the year ended December 31, 2013, reflected 229 days of oil delivery restrictions in Colombia compared with 162 days of oil delivery restrictions in 2012. In 2013, the impact of OTA pipeline disruptions on production was mitigated by selling a portion of our oil through trucking and an alternative pipeline.

Revenue and other income increased by 26% to $625.0 million for the year ended December 31, 2013, compared with $494.3 million in 2012.

For the year ended December 31, 2013, the average realized price per bbl for oil decreased by 11% to $92.21 compared with $103.04 in 2012. Average Brent oil prices for the year ended December 31, 2013, were $108.64 per bbl compared with $111.67 per bbl in 2012.

During the year ended December 31, 2013, sales using transportation alternatives were 64% of our oil and gas volumes sold in Colombia and the effect on the Colombian realized price was a reduction of approximately $9.68 per BOE compared with delivering all of our Colombian oil through the OTA pipeline.

During the second quarter of 2012, the recognition of additional royalties resulting from an arbitrator's decision on a dispute with a third party relating to the calculation of the third party's net profits interest on 50% of production from the Chaza Block in Colombia resulted in a $10.9 million revenue reduction. This amount related to July 2009 to May 2012 production. The recognition of this royalty resulted in a $2.27 per BOE reduction in the average realized price in the year ended December 31, 2012.

Operating expenses increased by 18% to $102.9 million for the year ended December 31, 2013, from $87.4 million in 2012. The increase was due to higher production levels partially offset by lower operating cost per BOE. On a per BOE basis, operating expenses decreased by 17% to $15.16 for the year ended December 31, 2013, from $18.17 in 2012. Operating costs per BOE decreased primarily due to lower transportation costs associated with OTA pipeline disruptions. Transportation costs were lower due to the absence of pipeline charges and trucking costs relating to volumes sold at the Costayaco battery. The trucking costs associated with the volumes sold at the Costayaco battery were a reduction to our realized price rather than recorded as transportation expenses. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the year ended December 31, 2013, was a reduction of $1.57 per BOE.

DD&A expenses increased by 51% to $184.7 million for the year ended December 31, 2013 from $122.1 million in 2012. The increase was due to increased production and an increase in the per BOE depletion rate. On a per BOE basis, DD&A expenses increased by 7% to $27.23 due to increased costs in the depletable base, partially offset by higher reserves.

For the year ended December 31, 2013, G&A expenses decreased by 26% to $17.0 million ($2.51 per BOE) from $23.0 million ($4.78 per BOE) in 2012. The decrease was due to increased G&A allocations to operating costs and capital projects, partially offset by increased salaries expense due to increased headcount from expanded operations. Additionally, bank fees were lower in 2013 due to lower tax installment payments resulting from a corporate reorganization in Colombia in the fourth quarter of 2012.

Other loss of $4.4 million in the year ended December 31, 2013, relates to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment within the quarter. We have filed an appeal against the judgment.

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

For the year ended December 31, 2013, the foreign exchange gain was $20.1 million, of which $18.8 million was an unrealized non-cash foreign exchange gain. In the year ended December 31, 2012, we incurred a foreign exchange loss of $26.7 million of which $17.1 million was an unrealized non-cash foreign exchange loss. Furthermore, in 2012, we had a realized foreign exchange loss of $9.5 million which primarily arose upon payment of 2011 Colombian income tax liabilities. This compares with $1.3 million realized foreign exchange gain in 2013.The Colombian peso weakened by 9% against the U.S. dollar in the year ended December 31, 2013. In the year ended December 31, 2012, the Colombian peso strengthened by 9% against the U.S. dollar.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the year ended December 31, 2014, were $214.9 million. During 2013, we also received proceeds of $1.5 million from the sale of our 15% working interest in the Mecaya Block in Colombia.

The following table provides a breakdown of capital expenditures in the three years ended December 31, 2014:

	Year Ended December 31,		
(Millions of U.S. Dollars)	2014	2013	2012
Drilling and completions	$117.5	$107.1	$103.1
Facilities and equipment	28.4	29.4	26.3
G&G	52.0	40.0	14.5
Other	17.0	13.5	9.4
	$214.9	$190.0	$153.3

The significant elements of our 2014 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), 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. We continued drilling the Corunta-1 exploration well, 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 on this block and performed facilities work on this block.

- We completed initial testing and evaluation of the Miraflor Oeste exploration well on the Guayuyaco Block (70% WI, operated). This oil well is currently on long-term test production.
- We acquired 2-D seismic and completed interpretation of the seismic data on the Piedemonte Sur Block (100%, operated), completed 3-D seismic on the Putumayo-1 Block (55% WI, operated) and 2-D seismic on the Cauca-7 Block (100% WI, operated), and commenced activities in preparation for the acquisition of 2-D seismic on the Putumayo-10 (100% WI, operated) Block. We continued G&G studies, including aeromagnetic surveys and completed the acquisition of 2-D seismic on the Sinu-1 (60% WI, operated) and Sinu-3 (51% WI, operated) Blocks. We completed regional field studies and continued work to obtain the necessary environmental and social permits for future seismic programs on the Chaza Block.
- We also continued facilities work at the Costayaco and Moqueta fields on the Chaza Block and the Llanos-22 Block.

Outlook - Colombia

The 2015 revised preliminary capital program in Colombia is $66 million with $24 million allocated to drilling, $22 million to facilities and pipelines and $20 million for G&G expenditures.

Our revised preliminary capital program for 2015 in Colombia includes completion of the Moqueta-17 development well on the Chaza Block, drill at least one additional well on this block and commence the acquisition of 2-D seismic on the Cauca-7, Putumayo-10 and Sinu-3 Blocks. Facilities work is also planned for the Chaza and Garibay Blocks.

Segmented Results from Continuing Operations – Peru

	Year Ended December 31,				
	2014	% Change	2013	% Change	2012
(Thousands of U.S. Dollars)					
Interest income	$1	(96)	$27	(45)	$49
Operating expenses	—	—	—	(100)	160
DD&A expenses	265,816	—	362	(71)	1,234
G&A expenses	6,448	17	5,524	21	4,573
Foreign exchange loss (gain)	1,944	61	1,208	(384)	(425)
	274,208	3,765	7,094	28	5,542
Loss from continuing operations before income taxes	$(274,207)	3,780	$(7,067)	29	$(5,493)

Segmented Results of Continuing Operations - Peru for the Year Ended December 31, 2014, Compared with the Results for the Years Ended December 31, 2013, and December 31, 2012

For the year ended December 31, 2014, loss from continuing operations before income taxes in Peru was $274.2 million, compared with $7.1 million in 2013 and $5.5 million in 2012. The increase in loss from continuing operations before income taxes was primarily due to an impairment loss in our Peru cost center of $265.1 million relating to costs incurred on Block 95. As previously discussed, in February 2015, we ceased all further development expenditures on the Bretaña field on Block 95 other than what is necessary to maintain tangible asset integrity and security and, as a result, costs capitalized in relation to the project were impaired as at December 31, 2014.

DD&A expenses for the year ended December 31, 2014, included $265.1 million of impairment charges as previously discussed. DD&A expenses for the year ended December 31, 2012, included $0.9 million of impairment charges relating to drilling costs from a dry well and seismic costs on blocks which were relinquished.

G&A expenses were $6.4 million in the year ended December 31, 2014, compared with $5.5 million in 2013 and $4.6 million in 2012. The increase in G&A expenses in each year was due to higher salaries expense as a result of an increased headcount and higher consulting fees due to expanded operations, partially offset by increased G&A allocations to capital projects.

For the year ended December 31, 2014, the foreign exchange loss was $1.9 million, compared with $1.2 million loss in 2013 and a gain of $0.4 million in 2012. The loss primarily relates to realized foreign exchange losses on monetary assets in Peru during the year. The Peruvian Nuevo Sol weakened by 7% and 9% against the U.S. dollar in each of the years ended December 31, 2014, and 2013, respectively, and strengthened by 5% in 2012.

Capital Program – Peru

Capital expenditures in our Peruvian segment for the year ended December 31, 2014, were $174.2 million. Capital expenditures in 2014 included drilling of $111.7 million, G&G expenditures of $37.7 million, facilities expenditures of $8.2 million and other expenditures of $16.6 million.

The significant elements of our 2014 capital program in Peru were:

- On Block 95 (100% WI, operated), 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 on Block 95 other than what is necessary to maintain tangible asset integrity and security.

- On Block 107 (100% WI, operated), we commenced the acquisition of 2-D seismic and continued the refurbishment of a base camp. On Block 133 (100% WI, operated), we continued work to obtain the necessary environmental and social permits for future seismic programs.

Outlook - Peru

The 2015 revised preliminary capital program in Peru is $45 million with $19 million allocated to drilling primarily for the Bretaña Sur 95-3-4-1X appraisal well on the L4 lobe on the Bretaña field, $10 million for facilities and $16 million for G&G expenditures. The budgeted Bretaña Sur 95-3-4-1X appraisal well drilling costs were primarily incurred in January and February 2015.

Our revised preliminary capital program for 2015 in Peru includes the identification and evaluation of options for the Bretaña field. On Block 107, we plan to continue the refurbishment of the base camp and commence the permitting process for the Osheki-1 exploration well.

Segmented Results from Continuing Operations - Brazil

	Year Ended December 31,				
	2014	% Change	2013	% Change	2012
(Thousands of U.S. Dollars)					
Oil and natural gas sales	$27,202	21	$22,545	129	$9,852
Interest income	1,604	76	909	50	607
	28,806	23	23,454	124	10,459
Operating expenses	6,848	(6)	7,311	58	4,637
DD&A expenses	9,932	(41)	16,761	(36)	26,300
G&A expenses	3,698	66	2,231	7	2,092
Foreign exchange loss (gain)	2,407	(1,310)	(199)	(110)	1,973
	22,885	(12)	26,104	(25)	35,002
Income (loss) from continuing operations before income taxes	$5,921	(323)	$(2,650)	(89)	$(24,543)
Production (1)					
Oil and NGL's, bbl	330,035	38	239,040	136	101,199
Average Prices					
Oil and NGL's per bbl	$82.42	(13)	$94.31	(3)	$97.35
Segmented Results of Operations per BOE					
Oil and natural gas sales	$82.42	(13)	$94.31	(3)	$97.35
Interest income	4.86	28	3.80	(37)	6.00
	87.28	(11)	98.11	(5)	103.35
Operating expenses	20.75	(32)	30.58	(33)	45.82
DD&A expenses	30.09	(57)	70.12	(73)	259.88
G&A expenses	11.20	20	9.33	(55)	20.67
Foreign exchange loss (gain)	7.29	(978)	(0.83)	(104)	19.50
	69.33	(37)	109.20	(68)	345.87
Income (loss) from continuing operations before income taxes	$17.95	(262)	$(11.09)	(95)	$(242.52)

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

Segmented Results of Continuing Operations - Brazil for the Year Ended December 31, 2014, Compared with the Results for the Years Ended December 31, 2013, and December 31, 2012

For the year ended December 31, 2014, income from continuing operations before income taxes was $5.9 million compared with a loss of $2.7 million in 2013 and $24.5 million in 2012. Income from continuing operations before income taxes resulted from increased oil and natural gas sales, decreased operating and DD&A expenses, partially offset by increased G&A expenses and foreign exchange losses. Loss before income taxes included a ceiling test impairment loss of $2.0 million in 2013 and $20.2 million in 2012.

Oil and NGL production in Brazil is from the Tiê field in Block 155 in the onshore Recôncavo Basin. Oil and NGL production for the year ended December 31, 2014, increased to 330.0 Mbbl or 904 bopd compared with 239.0 Mbbl or 655 bopd in 2013.

Production increased in the year ended December 31, 2014, compared with 2013 primarily as a result of the successful dual completion of the 4-GTE-04-BA well, partially offset by the impact of well downtime for workovers. Production increased in the year ended December 31, 2013, compared with 2012 primarily as a result of an increase in the number of producing wells from one to three during 2012 and a reduction in the number of days that production was shut-in in 2013 compared with 2012. During 2012, production was shut in between the expiry of the long-term test phase on July 31, 2012, and the declaration of commerciality for the Tiê field. Production recommenced on September 21, 2012, after the receipt of regulatory approval. Our production in Brazil was shut in for three weeks in October 2013 as a result of a strike by employees of Petróleo Brasileiro S.A. which affected the crude oil receiving terminal we use in the Recôncavo Basin. Our production in Brazil is currently limited due to gas flaring restrictions, but we are continuing to evaluate options to mitigate the effect of these restrictions.

Revenue and other income increased to $28.8 million for the year ended December 31, 2014, compared with $23.5 million in 2013 and $10.5 million in 2012. The increase in the year ended December 31, 2014, was due to higher oil production levels, partially offset by decreased average realized prices. The increase in the year ended December 31, 2013, was primarily as a result of increased oil production volumes. For the year ended December 31, 2014, the average realized price per bbl for oil decreased by 13% to $82.42 compared with $94.31 in 2013 and decreased from $97.35 in 2012. The price we receive in Brazil is at a discount to Brent due to refining and quality discounts.

Operating expenses decreased to $6.8 million for the year ended December 31, 2014, compared with $7.3 million in 2013. The effect of increased production was partially offset by decreased operating costs per BOE. On a per bbl basis, operating expenses decreased to $20.75 for the year ended December 31, 2014, from $30.58 per bbl in 2013. Operating expenses per bbl decreased in 2014 compared with 2013 due to lower water disposal and slickline services costs as a result of workovers, partially offset by increased workover expenses. For the year ended December 31, 2013, operating expenses increased to $7.3 million compared with $4.6 million in 2012, primarily due to higher production volumes. On a per bbl basis, operating expenses decreased in 2013 to $30.58 compared with $45.82 in 2012, due to increased production, partially offset by increased costs for water disposal and slickline services.

DD&A expenses were $9.9 million ($30.09 per bbl) in the year ended December 31, 2014, compared with $16.8 million ($70.12 per bbl) in 2013 and $26.3 million ($259.88 per bbl) in 2012. We recorded a ceiling test impairment loss of $2.0 million ($8.37 per bbl) in 2013 and $20.2 million ($199.61 per bbl) in 2012. On a per bbl basis, in addition to the 2013 impairment charge, the decrease was due to an increase in proved reserves and a decrease in costs in the depletable base relating to lower future development costs and the receipt of a termination payment relating to a former joint venture in the third quarter of 2013 that reduced the cost base. DD&A expenses in 2012 included a ceiling test impairment loss of $20.2 million relating to seismic and drilling costs on Block BM-CAL-10. In 2013, the effect of reduced ceiling test impairment losses was partially offset by the effect of increased costs in the depletable base, primarily related to the acquisition of the remaining 30% WI in four blocks in the Recôncavo Basin in October 2012.

G&A expenses were $3.7 million ($11.20 per bbl) in the year ended December 31, 2014, compared with $2.2 million ($9.33 per bbl) in 2013 and $2.1 million ($20.67 per bbl) in 2012.

For the year ended December 31, 2014, the foreign exchange loss was $2.4 million, compared with a foreign exchange gain of $0.2 million in 2013 and a loss of $2.0 million in 2012. The Brazilian Real weakened by 13%, 15%, and 11% against the U.S. dollar in the years ended December 31, 2014, 2013, and 2012 respectively.

Capital Program – Brazil

Capital expenditures in our Brazilian segment during the year ended December 31, 2014, were $24.3 million, including drilling of $16.1 million, G&G expenditures of $6.4 million and $1.8 million of other expenditures.

Our 2014 capital program in Brazil included:

- On Block REC-T-155 (100% WI, operated), we successfully completed the dual completions of the 3-GTE-03-BA and 4-GTE-04-BA development wells, 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.

- On Blocks REC-T-86, REC-T-117 and REC-T-118 (100% WI, operated), we commenced the acquisition of 3-D seismic.

Outlook – Brazil

The 2015 revised preliminary capital program in Brazil is $28 million with $7 million allocated to drilling, $8 million to facilities and pipelines and $13 million for G&G and other expenditures.

Our revised preliminary planned work program for 2015 in Brazil is expected to focus on facilities work, a workover on one of our producing wells in the Tiê field and seismic acquisition on Block REC-T-86, Block REC-T-117 and Block REC-T-118.
The First Appraisal Plan ("PAD") phase for Blocks REC-T-129, REC-T-142 and REC-T-155 will end May 24, 2015, before which must decide whether to move to the next exploration phase.

Segmented Results from Continuing Operations - Corporate Activities

	Year Ended December 31,				
	2014	% Change	2013 (1)	% Change	2012 (1)
(Thousands of U.S. Dollars)					
Interest income	$682	11	$615	59	$386
DD&A expenses	1,192	16	1,031	5	981
G&A expenses	21,671	32	16,364	(4)	16,975
Financial instruments loss	6,327	—	—	—	—
Foreign exchange loss (gain)	264	(34)	398	(23)	519
	29,454	66	17,793	(4)	18,475
Loss from continuing operations before income taxes	$(28,772)	67	$(17,178)	(5)	$(18,089)

(1) Certain entities which were previously reported in Corporate Activities were sold as part of the Argentina business unit and amounts previously reported in Corporate Activities related to these entities have been reclassified to loss from discontinued operations.

Results of Continuing Operations - Corporate Activities for the Year Ended December 31, 2014, Compared with the Results for the Years Ended December 31, 2013, and December 31, 2012

G&A expenses in the year ended December 31, 2014, were $21.7 million compared with $16.4 million in 2013. The increase in G&A expenses in 2014 was primarily due to higher salaries, consulting and information technology expenses associated with increased activity, partially offset by lower stock-based compensation expense associated with stock options and RSUs granted. During 2013, we received $1.0 million from the U.S. Federal Government for assets recovered from our former U.S. securities counsel as compensation for damages suffered in 2006. This amount was recorded as a reduction of G&A expenses in 2013.

G&A expenses in the year ended December 31, 2013, were $16.4 million compared with $17.0 million in 2012. The decrease in G&A expenses in 2013 was primarily due to an increase in costs recovered from business units, lower stock-based compensation expense and compensation for damages as noted above, partially offset by increased tax consulting fees. Stock-based compensation expense decreased due to less residual amortization of prior year higher value stock-based payment awards in 2013 and lower amortization of current year awards due to a later grant date than in 2012.

Financial instruments loss for the year ended December 31, 2014 was $6.3 million and consisted solely of unrealized financial instruments losses on the Madalena shares we received in connection with the sale of our Argentina business unit.

Results from Discontinued Operations

On June 25, 2014, we sold our Argentina business unit to Madalena for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares.

Loss from discontinued operations, net of income taxes was $27.0 million for the year ended December 31, 2014, compared with $54.7 million and $0.4 million, respectively, in 2013 and 2012. For the year ended December 31, 2014, loss from discontinued operations, net of tax, included loss on disposal of $19.3 million and loss from operations after income taxes of $7.7 million.

The following table presents results from discontinued operations before income taxes for the years ended December 31, 2014, 2013 and 2012. Results from discontinued operations before income taxes for the year ended December 31, 2014, were calculated to the date of sale of June 25, 2014.

	Year Ended December 31,				
	2014 (1)	% Change	2013 (2)	% Change	2012 (2)
(Thousands of U.S. Dollars)					
Oil and natural gas sales	$31,938	(57)	$73,495	(8)	$79,642
Interest income	47	(95)	1,019	176	369
	31,985	(57)	74,514	(7)	80,011
Operating expenses	14,612	(62)	38,886	19	32,696
DD&A expenses	13,684	(79)	64,295	104	31,466
G&A expenses	5,579	(55)	12,284	—	12,224
Foreign exchange loss	4,362	(33)	6,497	149	2,610
	38,237	(69)	121,962	54	78,996
(Loss) income from discontinued operations before income taxes	$(6,252)	(87)	$(47,448)	—	$1,015
Production (3)					
Oil and NGL's, bbl	377,795	(57)	882,110	(16)	1,047,265
Natural gas, Mcf	713,263	(47)	1,338,110	(1)	1,346,368
Total production, BOE	496,672	(55)	1,105,128	(13)	1,271,660
Average Prices					
Oil and NGL's per bbl	$75.98	(1)	$77.12	8	$71.12
Natural gas per Mcf	$4.53	11	$4.08	7	$3.83
Segmented Results of Operations per BOE					
Oil and natural gas sales	$64.30	(3)	$66.50	6	$62.63
Interest income	0.09	(90)	0.92	217	0.29
	64.39	(4)	67.42	7	62.92
Operating expenses	29.42	(16)	35.19	37	25.71
DD&A expenses	27.55	(53)	58.18	135	24.74
G&A expenses	11.23	1	11.12	16	9.61
Foreign exchange loss	8.78	49	5.88	187	2.05
	76.98	(30)	110.37	78	62.11
(Loss) income from discontinued operations before income taxes	$(12.59)	(71)	$(42.95)	—	$0.81

(1) Results from discontinued operations before income taxes for the year ended December 31, 2014, were calculated to the date of sale of June 25, 2014.

(2) Certain entities which were previously reported in Corporate Activities were sold as part of the Argentina business unit. Amounts in the table above include results of these entities which were insignificant in addition to results of the Argentina segment.

(3) Production represents production volumes NAR adjusted for inventory changes and losses.

Segmented Results of Discontinued Operations - Argentina for the Year Ended December 31, 2014, Compared with the Results for the Year Ended December 31, 2013

For the year ended December 31, 2014, loss from discontinued operations before income taxes in Argentina was $6.3 million compared with loss before taxes of $47.4 million in 2013. Loss from discontinued operations before income taxes in Argentina for the year ended December 31, 2013, included a ceiling test impairment loss of $30.8 million in our Argentina cost center due to a decrease in reserves as a result of deferred investment and inconclusive waterflood results on the Puesto Morales Block. Results from discontinued operations before income taxes for the year ended December 31, 2014, were calculated to the date of sale of June 25, 2014, and, therefore, included only approximately six months of results compared with twelve months in 2013. We reclassified the Argentina assets as assets held for sale on May 29, 2014, and ceased recognizing DD&A expense on the assets from this date.

Segmented Results of Discontinued Operations - Argentina for the Year Ended December 31, 2013, Compared with the Results for the Year Ended December 31, 2012

For the year ended December 31, 2013, loss from discontinued operations before income taxes in Argentina was $47.4 million compared with income before taxes of $1.0 million in 2012. In 2013, DD&A expenses included a ceiling test impairment loss of $30.8 million. Additionally, oil and natural gas sales decreased and operating expenses and foreign exchange losses increased.

Total oil and gas production from the Argentina segment decreased by 13% to 1.1 MMBOE, NAR and adjusted for inventory changes and losses, for the year ended December 31, 2013, compared with 1.3 MMBOE in 2012.

Oil and NGL production, NAR and adjusted for inventory changes and losses, decreased 16% to 0.9 MMbbl for the year ended December 31, 2013, compared with 1.0 MMbbl in 2012. The decrease was primarily due to the following: reduced production from the Puesto Morales Block due to expected production declines and well downtime for workovers; reduced production from the Surubi Block due to stabilization of Proa-2 production, which came on-stream in April 2012, and well downtime for workovers; and reduced production from the El Chivil Block due to well downtime for workovers. In 2013, gas production of 1.3 Bcf was consistent with 2012.

Revenue and other income decreased by 7% to $74.5 million for the year ended December 31, 2013, compared with $80.0 million in 2012. During the year ended December 31, 2013, we recognized $3.7 million, or $4.20 per bbl, upon the sale of some of our Petroleum Plus program credits. These credits were granted by the Argentina government to companies for new production of oil or natural gas, either from new discoveries, enhanced recovery techniques or reactivation of older fields.

In 2013, production decreases were partially offset by increased oil and natural gas prices. The average realized price for oil increased by 8% to $77.12 compared with $71.12 in 2012. As noted above, the impact of the sale of some of our Petroleum Plus program credits in the year ended December 31, 2013, was $4.20 per bbl. The prices we received in Argentina were influenced by the Argentina regulatory regime.

Operating expenses increased by 19% to $38.9 million for the year ended December 31, 2013, compared with $32.7 million in 2012. On a per BOE basis, operating expenses increased by 37% to $35.19 for the year ended December 31, 2013, from $25.71 in 2012. The increase in operating costs on a per BOE basis was primarily due to reduced production volumes, an increase of $4.73 per BOE in workover expenses and increased security on the Puesto Morales and Surubi Blocks, partially offset by reduced transportation costs. During the year ended December 31, 2013, workovers were performed on the Puesto Morales, Surubi, El Chivil, El Vinalar and Palmar Largo Blocks; whereas, in 2012, workovers were performed only on the Puesto Morales and Palmar Largo Blocks.

DD&A expenses increased by 104% to $64.3 million for the year ended December 31, 2013, compared with $31.5 million in 2012. DD&A expenses for the year ended December 31, 2013, included a ceiling test impairment loss of $30.8 million, as previously discussed. On a per BOE basis, DD&A expenses increased by 135% to $58.18 compared with $24.74 in 2012. The 2013 ceiling test impairment loss accounted for $27.87 per BOE of the increase. The remainder of the increase was due to increased costs in the depletable base and lower reserves.

G&A expenses were $12.3 million ($11.12 per BOE) in the year ended December 31, 2013, consistent with $12.2 million ($9.61 per BOE) in 2012.

For the year ended December 31, 2013, the foreign exchange loss was $6.5 million, compared with $2.6 million in 2012. The loss primarily relates to realized foreign exchange losses on monetary assets in Argentina during the year. The Argentina peso strengthened by 33% and 14% against the U.S. dollar in the years ended December 31, 2013, and 2012, respectively. The net monetary asset balance exposed to foreign exchange losses was higher throughout 2013 compared with 2012.

Capital Program - Argentina

Capital expenditures in our Argentina segment during the year ended December 31, 2014, were $18.3 million, including drilling of $14.5 million, G&G expenditures of $1.9 million, facilities of $0.8 million and other expenditures of $1.1 million. In 2014, in Argentina, we drilled and completed the Proa-3 development well on the Surubi Block (85% WI, operated) and completed workovers on wells on the Puesto Morales (100% WI, operated) and El Vinalar Blocks (100% WI, operated).

Liquidity and Capital Resources

At December 31, 2014, we had cash and cash equivalents of $331.8 million compared with $428.8 million at December 31, 2013, and $212.6 million at December 31, 2012.

We believe that our cash resources, including cash on hand and cash generated from operations, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2015, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc., in interest earning current accounts or are invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At December 31, 2014, 87% of our cash and cash equivalents were held by subsidiaries and partnerships outside of Canada and the United States. This cash was generally not available to fund domestic or head office operations unless funds were repatriated. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The government in Brazil requires us to register funds that enter and exit the country with the central bank. In Brazil and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in a special exchange regime, which allows us to receive revenue in U.S. dollars offshore. Beginning in 2013, transfers of branch profits are considered as dividends subject to a 25% tax if those profits have not already been subject to Colombian tax. We do not currently expect that this change in Colombian law will have a material consequence to us. In Peru, expenditures may be paid in local currency or U.S. dollars.

At December 31, 2014, one of our subsidiaries had a credit facility with a syndicate of banks, led by Wells Fargo Bank National Association as administrative agent. This reserve-based facility has a current borrowing base of $150 million and a maximum borrowing base that is dependent on the value of our reserves as assessed by the banking syndicate, but in no case would be more than $300 million. The borrowing base for the credit facility is supported by the present value of the petroleum reserves of two of our subsidiaries with operating branches in Colombia and our subsidiary in Brazil. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus a margin ranging between 2.25% and 3.25% per annum depending on the rate of borrowing base utilization. In addition, a stand-by fee of 0.875% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. The credit facility was entered into on August 30, 2013 and became effective on October 31, 2013 for a three-year term. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. Under the terms of the credit facility, we cannot pay any dividends to our shareholders if we are in default under the facility and, if we are not in default, we are required to obtain bank approval for any dividend payments exceeding $2.0 million in any fiscal year. No amounts have been drawn on this facility.

Cash Flows

During the year ended December 31, 2014, our cash and cash equivalents decreased by $97.0 million as a result of cash used in investing activities of $316.8 million (net of $30.4 million of cash provided by investing activities of discontinued operations), partially offset by cash provided by operating activities of $208.7 million (net of $4.8 million of cash used in operating activities of discontinued operations) and cash provided by financing activities of $11.1 million.

During the year ended December 31, 2013, our cash and cash equivalents increased by $216.2 million as a result of cash provided by operating activities of $520.9 million (including $31.1 million of cash provided by operating activities of discontinued operations) and cash provided by financing activities of $3.8 million, partially offset by cash used in investing activities of $308.5 million (including $18.8 million cash used in investing activities of discontinued operations).

During the year ended December 31, 2012, our cash and cash equivalents decreased by $139.1 million as a result of cash provided by operating activities of $156.3 million (including $27.4 million of cash provided by operating activities of discontinued operations) and cash provided by financing activities of $4.3 million, partially offset by cash used in investing activities of $299.7 million (including $37.0 million cash used in investing activities of discontinued operations).

Cash provided by operating activities of continuing operations in the year ended December 31, 2014, was primarily affected by
decreased oil and natural gas sales, increased operating and G&A expenses and a $97.9 million change in assets and liabilities from operating activities. These decreases were partially offset by realized foreign exchange and financial instruments gains and decreased income tax expenses. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $34.5 million primarily due to an increase in the number of days of sales outstanding in Colombia as a result of a higher portion of sales being to Ecopetrol which has longer payment terms than our other significant customers; inventory increased by $2.9 million primarily due to the timing of recognition of oil sales to a customer in Colombia where the sale is not recognized until the customer exports oil; accounts payable and accrued liabilities increased by $0.6 million due to the timing of payments for drilling activity and higher accruals for trucking costs; and net taxes payable decreased by $61.1 million primarily due to payment of 2013 income taxes in Colombia and lower current income taxes for 2014 in Colombia.

Cash provided by operating activities of continuing operations in the year ended December 31, 2013, was primarily affected by increased oil and natural gas sales, decreased G&A expenses, decreased realized foreign exchange losses and a $146.6 million change in assets and liabilities from operating activities. These increases were partially offset by increased operating and income tax expenses. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets decreased by $59.0 million primarily due to a reduction in the number of days of sales outstanding in Colombia which resulted from a larger portion of sales in 2013 being to a customer with more favorable payment terms; inventory decreased by $14.2 million primarily due to the reduced oil inventory in the OTA pipeline and associated Ecopetrol operated facilities in the Putumayo Basin and reduced oil inventory related to the timing of recognition of oil sales to a short-term customer in Colombia; accounts payable and accrued liabilities decreased by $8.8 million due to the timing of payments for drilling activity; and net taxes payable increased by $84.7 million due to increased taxable income in Colombia and the reimbursement of value added tax receivable in Colombia.

Cash provided by operating activities of continuing operations in the year ended December 31, 2012, was primarily affected by increased operating expenses and realized foreign exchange losses and a $163.9 million change in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets increased by $46.8 million due to the change in the timing of collection of Ecopetrol receivables and new customers in Colombia; inventory increased by $18.3 million primarily due to a change in the sales point under new sales agreements with Ecopetrol and increased sales to other third parties with different sales points due to the timing of the transfer of risks in Colombia; accounts payable and accrued liabilities decreased by $10.2 million due to the payment of royalties and reduced royalties payable resulting from lower production, partially offset by increased operating cost and other payables as a result of increased activity in all business units; and taxes receivable and payable decreased by $88.3 million as a result of a decrease in taxes payable due to utilization of tax losses and tax deductions resulting from a corporate reorganization and lower taxable income in Colombia, partially offset by an increase in taxes receivable due to value added tax and income tax recoveries in Colombia generated upon completion of the same corporate reorganization.

Cash outflows from investing activities of continuing operations in the year ended December 31, 2014, included cash capital expenditures of $347.0 million and an increase in restricted cash of $0.1 million. Cash outflows from investing activities of continuing operations in the year ended December 31, 2013, included cash capital expenditures of $343.6 million and an increase in restricted cash of $1.6 million, partially offset by proceeds from sale of oil and gas properties of $55.5 million. Cash outflows from investing activities of continuing operations in the year ended December 31, 2012, included cash capital expenditures of $238.2 million and cash paid for the 30% working interest acquisition in Brazil of $35.5 million, partially offset by a decrease in restricted cash of $11.0 million related to the same acquisition.

Cash provided by financing activities of continuing operations in the years ended December 31, 2014, 2013 and 2012 related to proceeds from issuance of shares of our Common Stock upon the exercise of stock options.

Off-Balance Sheet Arrangements

As at December 31, 2014, 2013 and 2012 we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2014:

	Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	More than 5 Years
(Thousands of U.S. Dollars)					
Oil transportation services	$22,252	$3,640	$7,280	$7,280	$4,052
Drilling and G&G	831	588	243	—	—
Operating leases	9,637	2,631	5,241	1,765	—
Software and telecommunication	620	260	360	—	—
	$33,340	$7,119	$13,124	$9,045	$4,052

The above table does not reflect estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties and other long-term liabilities, as we cannot determine with accuracy the timing of such payments. Information regarding our asset retirement obligation can be found in Note 9 to the Consolidated Financial Statements, Asset Retirement Obligation, in Item 8 “Financial Statements and Supplementary Data”,

At December 31, 2014, we had provided promissory notes totaling $86.3 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

As is customary in the oil and gas industry, we may at times have commitments in place to reserve or earn certain acreage positions or wells. If we do not meet such commitments, the acreage positions or wells may be lost.

Critical Accounting Policies and Estimates

The preparation of financial statements under GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as well as the revenues and expenses reported and disclosure of contingent liabilities. Changes in these estimates related to judgments and assumptions will occur as a result of changes in facts and circumstances or discovery of new information, and, accordingly, actual results could differ from amounts estimated.
On a regular basis we evaluate our estimates, judgments and assumptions. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

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

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

We follow the full cost method of accounting for our oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 to our annual consolidated financial statements. Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations ("ARO"), and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

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

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

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

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

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

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and distance from market. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2014, ceiling tests were based on wellhead prices per BOE as of the first day of each month within that twelve month period of $87.55 for Colombia and $84.63 for Brazil.

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

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

We assessed our oil and gas properties for impairment as at December 31, 2014, and found no impairment write-down was required based on our calculations for our Colombia and Brazil cost centers.

In the year ended December 31, 2014, we recorded an impairment loss of unproved properties in our Peru cost center of $265.1 million due to the lack of continued investment planned for Block 95.

In the year ended December 31, 2013, we recorded a ceiling test impairment loss of $2.0 million in our Brazil cost center as a result of lower realized prices and increased operating costs. In the year ended December 31, 2012, we recorded a ceiling test impairment loss in our Brazil cost center of $20.2 million related to seismic and drilling costs on Block BM-CAL-10.

If Brent oil prices continue to average $52.00 per bbl or below, we believe it is reasonably likely that we would record a ceiling test impairment loss in our Brazil cost center in the first or second quarter of 2015 and in our Colombia cost center in the fourth quarter of 2015.

Due to the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide a quantitative analysis of the effects of potential changes in these estimates. However, depending upon the duration and severity of the decline in oil prices that began in the fourth quarter of 2014 and continued through 2015 year-to-date, the average of prices in effect for the preceding 12-month period used in calculating future net cash flows for the purposes of the ceiling test may result in lower discounted cash flows that could potentially result in ceiling test impairments in future periods. Furthermore, depending on the duration and severity of the decline in oil prices, it is possible that decreases in estimates of proved reserves may occur for higher cost fields, resulting in higher DD&A expense in future periods.

Unproved properties

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

Asset Retirement Obligations

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

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

Allocation of Consideration Transferred in Business Combinations

The acquisition of properties in Brazil in 2012 was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recorded at their fair values at the acquisition date. The fair value of the consideration transferred was equal to the fair value of the net assets acquired and no gain or goodwill was recorded on acquisition. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, was subject to estimates which include various assumptions including the fair value of proved and unproved reserves of the assets acquired as well as future production and development costs and future oil and gas prices.

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

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over net identifiable assets acquired and liabilities assumed. The goodwill on our balance sheet resulted from the Solana Resources Limited and Argosy Energy International L.P. acquisitions, in 2008 and 2006 respectively, and relates entirely to the Colombia reporting unit.

At each reporting date, we assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. Changes in our future cash flows, operating results, growth rates, capital expenditures, cost of capital, discount rates, stock price or related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

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

At December 31, 2014, we obtained an independent valuation of our Colombia reporting unit and passed the first step of the goodwill impairment test at each of the low, medium, and high valuation cases. We passed the first step because the forward curve oil prices as at December 31, 2014 were appropriately used in the valuation, the goodwill resulted from acquisitions in Colombia, our most productive business unit, and the goodwill was generated on acquisitions also made during a previous period of low prices.

Income Taxes

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

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

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

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

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

Legal and Other Contingencies

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

Stock-Based Compensation

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

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

Derivative Activities

We purchase Colombian peso non-deliverable forward contracts for purposes of fixing the exchange rate at which we will purchase or sell Colombian pesos to settle our income tax installments and payments. Under the terms of our foreign exchange forward contracts, we will receive Colombian pesos and pay U.S. dollars or pay Colombian pesos and receive U.S. dollars based on a total notional amount.

The fair value of foreign currency derivatives is based on the maturity value of the foreign exchange non-deliverable forward contracts, using applicable forward exchange rates. The most significant variable to the cash flow calculations is the estimation of forward foreign exchange rates. The resulting net future cash inflows or outflows at maturity of the contracts are the net value of the contract.

Counterparty credit risk has not had a significant effect on our cash flow calculations and derivative valuations because we utilize a group of investment-grade rated counterparties, primarily financial institutions, for our derivative transactions. Because we have chosen not to qualify our derivatives for hedge accounting treatment, changes in the fair values of derivatives can have a significant impact on our reported results of operations. Generally, changes in derivative fair values will not impact our liquidity or capital resources.

Settlements of derivative instruments, regardless of whether they qualify for hedge accounting, do have an impact on our liquidity and results of operations. Generally, if actual market prices are higher than the price of the derivative instruments, our net earnings and cash flow from operations will be lower relative to the results that would have occurred absent these instruments. The opposite is also true.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2014-09, "Revenue from Contracts with Customers". The ASU creates a single source of revenue guidance for all companies in all industries and requires revenue recognition to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 sets forth a new revenue recognition model that requires identifying the contract, identifying the performance obligations, determining the transaction price, allocating the transaction price to performance obligations and recognizing the revenue upon satisfaction of performance obligations. The amendments in the ASU can be applied either retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the update recognized at the date of the initial application along with additional disclosures. The ASU will be effective for fiscal years and interim periods within those years, beginning after December 15, 2016. We are currently assessing the impact the new standard will have on its consolidated financial position, results of operations, cash flows and disclosure.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our principal market risk relates to oil prices. Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand and many other market factors outside of our control. Oil prices started falling in September 2014 and have fallen dramatically in December 2014 and January 2015. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to West Texas Intermediate ("WTI") or Brent and adjusted for quality each month.

Foreign currency risk

Foreign currency risk is a factor for our company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. We have engaged in non-deliverable foreign exchange contracts to buy or sell Colombian pesos in order to fix the exchange rate of our income tax installments and payments in Colombia. At December 31, 2014, we held Colombia peso non-deliverable forward contracts totaling 61.9 billion Colombian pesos.

Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil.

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

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $60,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The table below provides information about our foreign currency forward exchange agreements at December 31, 2014, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. We did not hold any foreign currency forward exchange agreements at December 31, 2013. Expected cash flows from th