GRAN TIERRA ENERGY INC.
Form 10-Q
November 12, 2013

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

| | |
|---|---|
| ý | QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 |

For the quarterly period ended September 30, 2013

or

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

For the transition period from __________ to __________

Commission file number 001-34018

GRAN TIERRA ENERGY INC.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Nevada | 98-0479924 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

300, 625 11 Avenue S.W.
Calgary, Alberta, Canada T2R 0E1
(Address of principal executive offices, including zip code)
(403) 265-3221
(Registrant's telephone number, including area code)

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 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

On November 6, 2013, the following number of shares of the registrant's capital stock were outstanding: 272,193,233 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 4,534,127 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 6,424,391 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

1

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Nine Months Ended September 30, 2013

Table of contents

## CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q, particularly in Item 2. “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 Quarterly Report on Form 10-Q, including without limitation statements in the Management’s Discussion and Analysis of Financial Condition and Results of Operations, regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words “believe”, “expect”, “anticipate”, “intend”, “estimate”, “project”, “target”, “goal”, “plan”, “objective”, “should”, or similar expressions or 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 II, Item 1A “Risk Factors” in this Quarterly Report on Form 10-Q. The information included herein is given as of the filing date of this Form 10-Q 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 Quarterly Report on Form 10-Q 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. Our reserves and sales 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. A farm-in or farm-out transaction refers to a contractual agreement with an owner who holds a working interest in an oil and gas lease to assign all or part of that interest to another party in exchange for fulfilling contractually specified conditions. Payment in a farm-in or farm-out transaction can be in cash and/or in kind by committing to perform and/or pay for certain work obligations. A farm-out agreement often stipulates that the other party must drill a well to a certain depth, at a specified location, within a certain time frame. 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.

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

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

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

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

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

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

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

- Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

i. The area of the reservoir considered as proved includes:

A. The area identified by drilling and limited by fluid contacts, if any, and

B. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

ii. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

iii. Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

iv. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

A. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

B. The project has been approved for development by all necessary parties and entities, including governmental entities.

v. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

i. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

ii. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

iii.

Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

iv. See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of section 210.4-10(a) of Regulations S-X.

- Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

5

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 - Financial Information

Item 1. Financial Statements

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| REVENUE AND OTHER INCOME | | | | |
| Oil and natural gas sales | $188,974 | $168,616 | $561,935 | $438,406 |
| Interest income | 684 | 317 | 1,904 | 1,628 |
| | 189,658 | 168,933 | 563,839 | 440,034 |
| EXPENSES | | | | |
| Operating | 35,588 | 36,295 | 108,505 | 88,115 |
| Depletion, depreciation, accretion and impairment (Note 4) | 58,875 | 45,044 | 180,309 | 137,982 |
| General and administrative | 14,673 | 12,896 | 37,840 | 46,394 |
| Foreign exchange loss (gain) | 1,880 | (1,315) | (15,329) | 27,867 |
| Other loss (Note 8) | — | — | 4,400 | — |
| | 111,016 | 92,920 | 315,725 | 300,358 |
| INCOME BEFORE INCOME TAXES | 78,642 | 76,013 | 248,114 | 139,676 |
| Income tax expense (Note 7) | (45,585) | (31,408) | (109,361) | (82,280) |
| NET INCOME AND COMPREHENSIVE INCOME | 33,057 | 44,605 | 138,753 | 57,396 |
| RETAINED EARNINGS, BEGINNING OF PERIOD | 390,369 | 197,805 | 284,673 | 185,014 |
| RETAINED EARNINGS, END OF PERIOD | $423,426 | $242,410 | $423,426 | $242,410 |
| NET INCOME PER SHARE — BASIC | $0.12 | $0.16 | $0.49 | $0.20 |
| NET INCOME PER SHARE — DILUTED | $0.12 | $0.16 | $0.49 | $0.20 |
| WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 5) | 283,092,224 | 281,695,212 | 282,687,871 | 280,387,484 |
| WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 5) | 286,026,519 | 284,605,162 | 285,820,007 | 283,968,384 |

(See notes to the condensed consolidated financial statements)

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

| | September 30, 2013 | December 31, 2012 |
|---|---|---|
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | $353,064 | $212,624 |
| Restricted cash | 3,819 | 1,404 |
| Accounts receivable | 143,915 | 119,844 |
| Inventory (Note 4) | 16,404 | 33,468 |
| Taxes receivable | 6,069 | 39,922 |
| Prepaids | 5,365 | 4,074 |
| Deferred tax assets (Note 7) | 2,090 | 2,517 |
| Total Current Assets | 530,726 | 413,853 |
| | | |
| Oil and Gas Properties (using the full cost method of accounting) | | |
| Proved | 790,193 | 813,247 |
| Unproved | 435,082 | 383,414 |
| Total Oil and Gas Properties | 1,225,275 | 1,196,661 |
| Other capital assets | 9,101 | 8,765 |
| Total Property, Plant and Equipment (Note 4) | 1,234,376 | 1,205,426 |
| | | |
| Other Long-Term Assets | | |
| Restricted cash | 3,305 | 1,619 |
| Deferred tax assets (Note 7) | 2,076 | 1,401 |
| Taxes receivable | 14,608 | 1,374 |
| Other long-term assets | 6,746 | 6,621 |
| Goodwill | 102,581 | 102,581 |
| Total Other Long-Term Assets | 129,316 | 113,596 |
| Total Assets | $1,894,418 | $1,732,875 |
| LIABILITIES AND SHAREHOLDERS’ EQUITY | | |
| Current Liabilities | | |
| Accounts payable | $70,783 | $102,263 |
| Accrued liabilities | 79,934 | 66,418 |
| Taxes payable | 88,757 | 22,339 |
| Deferred tax liabilities (Note 7) | 1,643 | 337 |
| Asset retirement obligation (Note 6) | — | 28 |
| Total Current Liabilities | 241,117 | 191,385 |
| | | |
| Long-Term Liabilities | | |
| Deferred tax liabilities (Note 7) | 183,925 | 225,195 |
| Equity tax payable (Note 7) | — | 3,562 |
| Asset retirement obligation (Note 6) | 20,388 | 18,264 |
| Other long-term liabilities | 9,015 | 3,038 |
| Total Long-Term Liabilities | 213,328 | 250,059 |
| | | |
| Contingencies (Note 8) | | |
| Shareholders’ Equity | | |

| | | |
|---|---|---|
| Common Stock (Note 5) (271,872,896 and 268,482,445 shares of Common Stock and 11,278,855 and 13,421,488 exchangeable shares, par value $0.001 per share, issued and outstanding as at September 30, 2013 and December 31, 2012, respectively) | 10,020 | 7,986 |
| Additional paid in capital | 1,006,527 | 998,772 |
| Retained earnings | 423,426 | 284,673 |
| Total Shareholders' Equity | 1,439,973 | 1,291,431 |
| Total Liabilities and Shareholders' Equity | $1,894,418 | $1,732,875 |

(See notes to the condensed consolidated financial statements)

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2013 | 2012 |
| Operating Activities | | |
| Net income | $138,753 | $57,396 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depletion, depreciation, accretion and impairment | 180,309 | 137,982 |
| Deferred tax recovery (Note 7) | (23,791) | (8,855) |
| Stock-based compensation (Note 5) | 6,113 | 9,854 |
| Unrealized foreign exchange (gain) loss | (16,853) | 14,072 |
| Cash settlement of asset retirement obligation | (927) | (404) |
| Equity tax | (3,345) | (3,534) |
| Other loss (Note 8) | 4,400 | — |
| Net change in assets and liabilities from operating activities | | |
| Accounts receivable and other long-term assets | (26,284) | (96,656) |
| Inventory | 12,366 | (9,769) |
| Prepaids | (1,291) | 1,087 |
| Accounts payable and accrued and other liabilities | (7,593) | (25,960) |
| Taxes receivable and payable | 87,230 | (59,281) |
| Net cash provided by operating activities | 349,087 | 15,932 |
| | | |
| Investing Activities | | |
| Increase in restricted cash | (4,101) | (21,704) |
| Additions to property, plant and equipment | (267,642) | (222,119) |
| Proceeds from oil and gas properties (Note 4) | 59,621 | — |
| Net cash used in investing activities | (212,122) | (243,823) |
| | | |
| Financing Activities | | |
| Proceeds from issuance of shares of Common Stock (Note 5) | 3,475 | 3,797 |
| Net cash provided by financing activities | 3,475 | 3,797 |
| | | |
| Net increase (decrease) in cash and cash equivalents | 140,440 | (224,094) |
| Cash and cash equivalents, beginning of period | 212,624 | 351,685 |
| Cash and cash equivalents, end of period | $353,064 | $127,591 |
| | | |
| Cash | $296,520 | $99,442 |
| Term deposits | 56,544 | 28,149 |
| Cash and cash equivalents, end of period | $353,064 | $127,591 |
| | | |
| Supplemental cash flow disclosures: | | |
| Cash paid for income taxes | $38,978 | $140,069 |
| | | |
| Non-cash investing activities: | | |
| Non-cash net assets and liabilities related to property, plant and equipment, end of period | $65,645 | $33,961 |

(See notes to the condensed consolidated financial statements)

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

| | Nine Months Ended September 30, 2013 | Year Ended December 31, 2012 |
|---|---|---|
| Share Capital | | |
| Balance, beginning of period | $7,986 | $7,510 |
| Issue of shares of Common Stock (Note 5) | 2,034 | 476 |
| Balance, end of period | 10,020 | 7,986 |
| | | |
| Additional Paid in Capital | | |
| Balance, beginning of period | 998,772 | 980,014 |
| Issue of shares of Common Stock (Note 5) | — | 2,902 |
| Exercise of warrants | — | 1,590 |
| Expiry of warrants | — | 190 |
| Exercise of stock options (Note 5) | 1,441 | 960 |
| Stock-based compensation (Note 5) | 6,314 | 13,116 |
| Balance, end of period | 1,006,527 | 998,772 |
| | | |
| Warrants | | |
| Balance, beginning of period | — | 1,780 |
| Exercise of warrants | — | (1,590) |
| Expiry of warrants | — | (190) |
| Balance, end of period | — | — |
| | | |
| Retained Earnings | | |
| Balance, beginning of period | 284,673 | 185,014 |
| Net income | 138,753 | 99,659 |
| Balance, end of period | 423,426 | 284,673 |
| | | |
| Total Shareholders' Equity | $1,439,973 | $1,291,431 |

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Condensed Consolidated Financial Statements (Unaudited)
(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

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

2. Significant Accounting Policies

These interim unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”). The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for the fair presentation of results for the interim periods.

The note disclosure requirements of annual consolidated financial statements provide additional disclosures to that required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements as at and for the year ended December 31, 2012, included in the Company’s 2012 Annual Report on Form 10-K, filed with the Securities and Exchange Commission (“SEC”) on February 26, 2013.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2012 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as disclosed below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

Restricted Stock Units

In May 2013, the Company's Board of Directors determined that the Company will annually grant time-vested restricted stock units ("RSUs") to officers, employees and consultants. RSUs entitle the holder to receive, at the option of the Company, either the underlying number of shares of the Company's Common Stock upon vesting of such shares or a cash payment equal to the value of the underlying shares. The Company expects its practice will be to settle RSUs in cash and, therefore, RSUs are accounted for as liability instruments. Compensation expense for RSUs granted is based on the estimated fair value, which is determined using the closing share price, at each reporting date, and the expense, net of estimated forfeitures, is recognized over the requisite service period using the accelerated method, with a corresponding change to liabilities. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures related to vested awards. Additionally, the Company will continue to grant options to purchase shares of Common Stock to certain directors, officers, employees and consultants. Stock-based compensation expense relating to RSUs and stock options is capitalized as part of oil and natural gas properties or expensed as part of operating expenses or general and administrative (“G&A”) expenses, as appropriate.

Recently Issued Accounting Pronouncements

Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is fixed at the Reporting Date

In February 2013, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2013- 04, “Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is fixed at the Reporting Date”. The ASU provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The implementation of this update is not expected to materially impact the Company’s consolidated financial position, results of operations or cash flows.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

In July 2013, the FASB issued ASU 2013-11, “Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists". The ASU provides guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The implementation of this update is not expected to materially impact the Company’s consolidated financial position, results of operations or cash flows.

3. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company’s reportable segments are Colombia, Argentina, Peru and Brazil based on geographic organization. The level of activity in Peru and Brazil was not significant at September 30, 2013, or December 31, 2012; however, the Company has separately disclosed its results of operations in Peru and Brazil as reportable segments. The All Other category represents the Company’s corporate activities.

The accounting policies of the reportable segments are the same as those described in Note 2. The Company evaluates reportable segment performance based on income or loss before income taxes.

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

| Three Months Ended September 30, 2013 | | | | | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars, except per unit of production amounts) | Colombia | Argentina | Peru | Brazil | All Other | Total |
| Oil and natural gas sales | $164,241 | $18,149 | $— | $6,584 | $— | $188,974 |
| Interest income | 111 | 164 | — | 281 | 128 | 684 |
| Depletion, depreciation, accretion and impairment | 46,821 | 7,606 | 73 | 4,129 | 246 | 58,875 |
| Depletion, depreciation, accretion and impairment - per unit of production | 27.48 | 30.51 | — | 59.72 | — | 29.12 |
| Income (loss) before income taxes | 89,214 | (4,164) | (1,404) | (337) | (4,667) | 78,642 |
| Segment capital expenditures (1) | $39,608 | $8,159 | $11,063 | $(22,500) | $289 | $36,619 |

| Three Months Ended September 30, 2012 | | | | | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars, except per unit of production amounts) | Colombia | Argentina | Peru | Brazil | All Other | Total |
| Oil and natural gas sales | $145,610 | $22,332 | $— | $674 | $— | $168,616 |
| Interest income | 171 | 10 | — | 40 | 96 | 317 |
| Depletion, depreciation, accretion and impairment | 35,255 | 9,165 | 68 | 305 | 251 | 45,044 |
| Depletion, depreciation, accretion and impairment - per unit of production | 24.46 | 26.60 | — | 40.35 | — | 25.12 |
| Income (loss) before income taxes | 79,915 | 1,777 | (847) | (1,170) | (3,662) | 76,013 |
| Segment capital expenditures | $35,880 | $11,568 | $11,204 | $2,838 | $300 | $61,790 |

| Nine Months Ended September 30, 2013 | | | | | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars, except per unit of production amounts) | Colombia | Argentina | Peru | Brazil | All Other | Total |
| Oil and natural gas sales | $488,577 | $54,620 | $— | $18,738 | $— | $561,935 |
| Interest income | 415 | 710 | 27 | 292 | 460 | 1,904 |
| Depletion, depreciation, accretion and impairment | 141,141 | 22,986 | 272 | 15,143 | 767 | 180,309 |
| Depletion, depreciation, accretion and impairment - per unit of production | 27.58 | 27.79 | — | 75.74 | — | 29.35 |
| Income (loss) before income taxes | 275,353 | (6,183) | (4,984) | (3,663) | (12,409) | 248,114 |
| Segment capital expenditures (1) | $118,758 | $12,424 | $59,911 | $12,021 | $528 | $203,642 |

| Nine Months Ended September 30, 2012 | | | | | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars, except per unit of production amounts) | Colombia | Argentina | Peru | Brazil | All Other | Total |
| Oil and natural gas sales | $376,261 | $59,183 | $— | $2,962 | $— | $438,406 |
| Interest income | 598 | 96 | 15 | 607 | 312 | 1,628 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Depletion, depreciation, accretion and impairment | 90,625 | 23,080 | 1,174 | 22,379 | 724 | 137,982 |
| Depletion, depreciation, accretion and impairment - per unit of production | 24.96 | 24.54 | — | 708.76 | — | 29.98 |
| Income (loss) before income taxes | 182,516 | 2,568 | (4,147) | (24,467) | (16,794) | 139,676 |
| Segment capital expenditures | $98,476 | $28,412 | $43,866 | $44,536 | $695 | $215,985 |

(1) In the third quarter of 2013, segment capital expenditures in Brazil are net of proceeds of $54.0 million relating to termination of a farm-in agreement. Additionally, segment capital expenditures for the nine months ended September 30, 2013, are net of proceeds of $4.1 million relating to the Company's assumption of the remaining 50% working interest in the Santa Victoria Block in Argentina and $1.5 million relating to the Company's sale of its 15% working interest in the Mecaya Block in Colombia (Note 4).

| | As at September 30, 2013 | | | | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars) | Colombia | Argentina | Peru | Brazil | All Other | Total |
| Property, plant and equipment | $822,522 | $128,799 | $155,579 | $124,418 | $3,058 | $1,234,376 |
| Goodwill | 102,581 | — | — | — | — | 102,581 |
| Other assets | 267,186 | 37,320 | 18,285 | 50,555 | 184,115 | 557,461 |
| Total Assets | $1,192,289 | $166,119 | $173,864 | $174,973 | $187,173 | $1,894,418 |

| | As at December 31, 2012 | | | | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars) | Colombia | Argentina | Peru | Brazil | All Other | Total |
| Property, plant and equipment | $840,027 | $138,768 | $95,940 | $127,394 | $3,297 | $1,205,426 |
| Goodwill | 102,581 | — | — | — | — | 102,581 |
| Other assets | 222,220 | 47,038 | 10,880 | 8,498 | 136,232 | 424,868 |
| Total Assets | $1,164,828 | $185,806 | $106,820 | $135,892 | $139,529 | $1,732,875 |

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

In the nine months ended September 30, 2013, the Company had two significant customers in Colombia: Ecopetrol S.A. ("Ecopetrol") and one other customer, which accounted for 52% and 29%, respectively, of the Company's consolidated oil and natural gas sales. For the three months ended September 30, 2013, these customers accounted for 56% and 28%, respectively, of the Company's consolidated oil and natural gas sales. In the nine months ended September 30, 2012, the Company had one significant customer in Colombia: Ecopetrol. For the three and nine months ended September 30, 2012, sales to Ecopetrol accounted for 71% and 77%, respectively, of the Company's consolidated oil and natural gas sales. For the three months ended September 30, 2012, the Company had an additional short-term significant customer , which accounted for 13% of the Company's revenues during the period.

4. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

| | As at September 30, 2013 | | | As at December 31, 2012 | | |
|---|---|---|---|---|---|---|
| (Thousands of U.S. Dollars) | Cost | Accumulated depletion, depreciation and impairment | Net book value | Cost | Accumulated depletion, depreciation and impairment | Net book value |
| Oil and natural gas properties | | | | | | |
| Proved | $1,710,788 | $(920,595) | $790,193 | $1,562,477 | $(749,230) | $813,247 |
| Unproved | 435,082 | — | 435,082 | 383,414 | — | 383,414 |
| | 2,145,870 | (920,595) | 1,225,275 | 1,945,891 | (749,230) | 1,196,661 |
| Furniture and fixtures and leasehold improvements | 8,215 | (6,203) | 2,012 | 7,575 | (5,093) | 2,482 |
| Computer equipment | 14,018 | (7,458) | 6,560 | 10,971 | (5,248) | 5,723 |
| Automobiles | 1,352 | (823) | 529 | 1,376 | (816) | 560 |
| Total Property, Plant and Equipment | $2,169,455 | $(935,079) | $1,234,376 | $1,965,813 | $(760,387) | $1,205,426 |

Depletion and depreciation expense on property, plant and equipment for the three months ended September 30, 2013, was $59.1 million (three months ended September 30, 2012 - $43.0 million) and for the nine months ended September 30, 2013, was $172.7 million (nine months ended September 30, 2012 - $120.8 million). A portion of depletion and depreciation expense was recorded as inventory in each period and adjusted for inventory changes.

In the second quarter of 2013, the Company recorded a ceiling test impairment loss of $2.0 million in the Company's Brazil cost center as a result of lower realized prices and increased operating costs.

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

In the second quarter of 2013, the Company assumed its partner's 50% working interest in the Santa Victoria Block in Argentina and received cash consideration of $4.1 million from its partner, comprising the balance owing for carry consideration and compensation for the second exploration phase work commitment. The Company also received proceeds of $1.5 million relating to a sale of its 15% working interest in the Mecaya Block in Colombia.

During the third quarter of 2013, the Company received a net payment of $54.0 million (before income taxes) from a third party in connection with termination of a farm-in agreement in the Recôncavo Basin relating to Block REC-T-129, Block REC-T-142, Block REC-T-155 and Block REC-T-224.

The Company successfully bid on three blocks in the 2013 Brazil Bid Round administered by Brazil's Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") and, in the third quarter of 2013, paid a signature bonus of $14.4 million upon finalization of the concession agreement.

In Brazil, the exploration phase of the concession agreements on Blocks REC-T-129, REC-T-142 and REC-T-155 is due to expire on November 24, 2013; however, under the concession agreements the Company is able and has submitted an application to the ANP for extension of the exploration phase of these blocks. Additionally, the exploration phase of the concession agreement on Block REC-T-224 is due to expire on December 11, 2013, but we plan to apply for an extension of the exploration phase of this block. At September 30, 2013, unproved properties included $59.6 million relating to these four blocks. Management assessed these blocks for impairment at September 30, 2013 and concluded no impairment had occurred.

In Argentina, Rio Negro Province has enacted legislation that changes the royalty regime associated with concession agreement extensions. The Company is negotiating concession agreement extensions and royalty rates for its Puesto Morales, Puesto Morales Este, Rinconada Norte and Rinconada Sur Blocks and expects that royalty rates in Rio Negro Province will likely increase and a bonus payment, not determinable at this time, may be payable for the concession agreement extensions.

The amounts of G&A expenses and stock-based compensation capitalized in each of the Company's cost centers were as follows:

| | Nine Months Ended September 30, 2013 | | | | |
|---|---|---|---|---|---|
| (Thousands of U.S. Dollars) | Colombia | Argentina | Peru | Brazil | Total |
| Capitalized G&A, including stock-based compensation | $14,746 | $2,896 | $5,981 | $5,813 | $29,436 |
| Capitalized stock-based compensation | $794 | $171 | $571 | $566 | $2,102 |

| | Nine Months Ended September 30, 2012 | | | | |
|---|---|---|---|---|---|
| (Thousands of U.S. Dollars) | Colombia | Argentina | Peru | Brazil | Total |
| Capitalized G&A, including stock-based compensation | $9,279 | $3,480 | $3,670 | $2,653 | $19,082 |
| Capitalized stock-based compensation | $376 | $275 | $— | $216 | $867 |

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. As at September 30, 2013, the Company had $163.0 million (December 31, 2012 - $175.9 million) of unproved assets in Colombia, $39.5 million (December 31, 2012 - $42.3 million) of unproved assets in Argentina, $154.6 million (December 31, 2012 - $95.1 million) of unproved assets in Peru, and $78.0 million (December 31, 2012 - $70.1 million) of unproved assets in Brazil for a total of $435.1 million (December 31, 2012 - $383.4 million). These properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed. The Company expects that approximately 62% of costs not subject to depletion at September 30, 2013, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

Inventory

At September 30, 2013, oil and supplies inventories were $14.6 million and $1.8 million, respectively (December 31, 2012 - $31.2 million and $2.3 million, respectively).

5. Share Capital

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

As at September 30, 2013, outstanding share capital consists of 271,872,896 shares of Common Stock of the Company, 6,744,728 exchangeable shares of Gran Tierra Exchangeco Inc., (the "Exchangeco exchangeable shares") and 4,534,127 exchangeable shares of Gran Tierra Goldstrike Inc. (the "Goldstrike exchangeable shares"). The redemption date of the Exchangeco exchangeable shares was previously established as November 14, 2013 (or at an earlier date under certain specified circumstances). However, pursuant to resolutions of the board of directors of Gran Tierra Exchangeco Inc., effective October 25, 2013, the redemption date for the Exchangeco exchangeable shares was extended to such later date as may be established by the board of directors of Gran Tierra Exchangeco Inc. at its discretion. The redemption date of the Goldstrike exchangeable shares was previously established as November 10, 2013. However, pursuant to resolutions of the board of directors of Gran Tierra Goldstrike Inc., effective October 31, 2013, the redemption date for the Goldstrike exchangeable shares was extended to such later date as may be established by the board of directors of Gran Tierra Goldstrike Inc. at its discretion. During the nine months ended September 30, 2013, 1,247,818 shares of Common Stock were issued upon the exercise of stock options, 452,950 shares of Common Stock were issued upon the exchange of the Exchangeco exchangeable shares and 1,689,683 shares of Common Stock were issued upon the exchange of the Goldstrike exchangeable shares.

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

The Exchangeco exchangeable shares were issued upon acquisition of Solana Resources Limited. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. Holders of exchangeable shares have substantially the same rights as holders of shares of Common Stock. Each exchangeable share is exchangeable into one share of Common Stock of the Company.

Restricted Stock Units and Stock Options

In May 2013, the Company issued RSUs and stock options, which will vest as to 1/3 of the awards on each of March 1, 2014, March 1, 2015 and March 1, 2016. The term of options granted starting May 2013 is five years or three months after the grantee's end of service to the Company, whichever occurs first. Options granted prior to May 2013 continue to have a term of ten years or three months after the grantee's end of service to the Company, whichever occurs first. Once an RSU is vested, it is immediately settled and considered to be at the end of its term.

The following table provides information about long-term incentive plan ("LTIP") activity for the nine months ended September 30, 2013:

| | RSUs Number of Outstanding Share Units | Options Number of Outstanding Options | Weighted Average Exercise Price $/Option |
|---|---|---|---|
| Balance, December 31, 2012 | — | 15,399,662 | 5.11 |
| Granted | 939,365 | 2,066,935 | 6.27 |
| Exercised | — | (1,247,818) | (2.79) |
| Forfeited | (21,655) | (284,835) | (6.17) |
| Expired | — | (102,593) | (6.57) |
| Balance, September 30, 2013 | 917,710 | 15,831,351 | 5.42 |

For the nine months ended September 30, 2013, 1,247,818 shares of Common Stock were issued for cash proceeds of $3.5 million upon the exercise of 1,247,818 stock options (nine months ended September 30, 2012 - $3.8 million).

The weighted average grant date fair value for options granted in the three months ended September 30, 2013, was $2.34 (three months ended September 30, 2012 - $2.62) and for the nine months ended September 30, 2013, was $2.62 (nine months ended September 30, 2012 - $3.36). As a result of the change in the term of stock options to five years for stock options granted starting May 2013, the weighted average volatility used in the Black-Scholes option pricing model was reduced to 43% for the three months ended September 30, 2013 and 53% for the nine months ended September 30, 2013, from 75% for the year ended December 31, 2012, resulting in a lower grant date fair value per share than in prior periods.

The amounts recognized for stock-based compensation were as follows:

| (Thousands of U.S. Dollars) | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Compensation costs for stock options | $ 2,132 | $ 3,268 | $ 6,314 | $ 10,721 |
| Compensation costs for RSUs | 1,282 | — | 1,901 | — |
| | 3,414 | 3,268 | 8,215 | 10,721 |
| Less: stock-based compensation costs capitalized | (1,717) | (336) | (2,102) | (867) |
| Total stock-based compensation expense | $ 1,697 | $ 2,932 | $ 6,113 | $ 9,854 |

Of the total compensation expense for the three months ended September 30, 2013, $1.3 million (three months ended September 30, 2012 - $2.6 million) was recorded in G&A expenses and $0.4 million (three months ended September 30, 2012 – $0.3 million) was recorded in operating expenses. Of the total compensation expense for the nine months ended September 30, 2013, $5.3 million (nine months ended September 30, 2012 – $8.9 million) was recorded in G&A expenses and $0.8 million (nine months ended September 30, 2012 – $0.9 million) was recorded in operating expenses.

At September 30, 2013, there was $11.3 million (December 31, 2012 - $8.2 million) of unrecognized compensation cost related to unvested LTIP units which is expected to be recognized over a weighted average period of 2.1 years.

Net income per share

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

| | Three Months Ended September 30, 2013 | 2012 | Nine Months Ended September 30, 2013 | 2012 |
|---|---|---|---|---|
| Weighted average number of common and exchangeable shares outstanding | 283,092,224 | 281,695,212 | 282,687,871 | 280,387,484 |
| Shares issuable pursuant to warrants | — | — | — | 235,582 |
| Shares issuable pursuant to stock options | 12,428,489 | 5,643,730 | 10,823,968 | 5,947,880 |
| Shares assumed to be purchased from proceeds of stock options | (9,494,194) | (2,733,780) | (7,691,832) | (2,602,562) |
| Weighted average number of diluted common and exchangeable shares outstanding | 286,026,519 | 284,605,162 | 285,820,007 | 283,968,384 |

For the three months ended September 30, 2013, 3,472,472 options (three months ended September 30, 2012 - 9,957,585 options) were excluded from the diluted income per share calculation as the options were anti-dilutive. For the nine months ended September 30, 2013, 5,584,732 options (nine months ended September 30, 2012 - 9,808,758 options) were excluded from the diluted income per share calculation as the options were anti-dilutive.

6. Asset Retirement Obligation

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

| (Thousands of U.S. Dollars) | Nine Months Ended September 30, 2013 | Year Ended December 31, 2012 |
|---|---|---|
| Balance, beginning of year | $18,292 | $12,669 |
| Settlements | (2,068) | (404) |
| Liability incurred | 1,397 | 5,190 |
| Liability assumed in a business combination | — | 410 |
| Foreign exchange | (23) | 45 |
| Accretion | 918 | 998 |
| Revisions in estimated liability | 1,872 | (616) |
| Balance, end of period | $20,388 | $18,292 |
| | | |
| Asset retirement obligation - current | $— | $28 |
| Asset retirement obligation - long-term | 20,388 | 18,264 |
| Balance, end of period | $20,388 | $18,292 |

For the nine months ended September 30, 2013, settlements included cash payments of $0.9 million with the balance in accounts payable and accrued liabilities at September 30, 2013. Revisions to estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. At September 30, 2013, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was $1.9 million (December 31, 2012 - $1.3 million).

7. Taxes

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

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| (Thousands of U.S. Dollars) | 2013 | | 2012 | |
| Income (loss) before income taxes | | | | |
| United States | $(8,488 | ) | $(7,942 | ) |
| Foreign | 256,602 | | 147,618 | |
| | 248,114 | | 139,676 | |
| | 35 | % | 35 | % |
| Income tax expense expected | 86,840 | | 48,887 | |
| Foreign currency translation adjustments | (7,649 | ) | 8,025 | |
| Impact of foreign taxes | 1,908 | | 2,716 | |
| Stock-based compensation | 1,943 | | 3,277 | |
| Increase in valuation allowance | 22,700 | | 9,304 | |
| Branch and other foreign loss pick-up | (2,013 | ) | (4,358 | ) |
| Non-deductible third party royalty in Colombia | 8,812 | | 9,951 | |
| Other permanent differences | (3,180 | ) | 4,478 | |
| Total income tax expense | $109,361 | | $82,280 | |
| | | | | |
| Current income tax expense | | | | |
| United States | $813 | | $778 | |
| Foreign | 132,339 | | 90,357 | |
| | 133,152 | | 91,135 | |
| Deferred income tax recovery | | | | |
| United States | — | | — | |
| Foreign | (23,791 | ) | (8,855 | ) |
| | (23,791 | ) | (8,855 | ) |
| Total income tax expense | $109,361 | | $82,280 | |

| (Thousands of U.S. Dollars) | As at September 30, 2013 | December 31, 2012 |
|---|---|---|
| Deferred Tax Assets | | |
| Tax benefit of operating loss carryforwards | $53,693 | $51,920 |
| Tax basis in excess of book basis | 44,500 | 22,519 |
| Foreign tax credits and other accruals | 30,550 | 30,926 |
| Tax benefit of capital loss carryforwards | 4,835 | 4,779 |
| Deferred tax assets before valuation allowance | 133,578 | 110,144 |
| Valuation allowance | (129,412) | (106,226) |
| | $4,166 | $3,918 |
| Deferred tax assets - current | $2,090 | $2,517 |
| Deferred tax assets - long-term | 2,076 | 1,401 |
| | 4,166 | 3,918 |
| Deferred tax liabilities - current | (1,643) | (337) |
| Deferred tax liabilities - long-term | (183,925) | (225,195) |
| | (185,568) | (225,532) |
| Net Deferred Tax Liabilities | $(181,402) | $(221,614) |

As at September 30, 2013, the Company had operating loss carryforwards of $233.7 million (December 31, 2012 - $213.1 million) and capital loss carryforwards of $32.6 million (December 31, 2012 – $35.9 million) before valuation allowance. Of these operating loss carryforwards and capital loss carryforwards, $233.8 million (December 31, 2012 - $215.2 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between 2014 and 2033 and the capital loss carryforwards expire between 2014 and 2017, while certain other jurisdictions allow operating losses to be carried forward indefinitely.

As at September 30, 2013, the total amount of Gran Tierra's unrecognized tax benefit was approximately $19.8 million (December 31, 2012 - $21.8 million), a portion of which, if recognized, would affect the Company's effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations.

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

| | Nine Months Ended September 30, 2013 | 2012 |
|---|---|---|
| (Thousands of U.S. Dollars) | | |
| Unrecognized tax benefit at beginning of period | $21,800 | $20,500 |
| Changes for positions relating to prior year | (2,000) | — |
| Unrecognized tax benefit at end of period | $19,800 | $20,500 |

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

The equity tax liability at September 30, 2013, and December 31, 2012, includes a Colombian tax of 6% on a legislated measure and was calculated based on the Company's Colombian segment's balance sheet equity for tax purposes at January 1, 2011. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period. The equity tax liability also partially related to an equity tax liability assumed upon the 2011 acquisition of Petrolifera Petroleum Limited.

8. Contingencies

Gran Tierra Energy Colombia, Ltd. and Petrolifera Petroleum Exploration (Colombia) Ltd (collectively “GTEC”) and Ecopetrol, the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long-term test of the Guayuyaco-1 and Guayuyaco-2 wells, prior to GTEC's purchase of the companies originally involved in the dispute. There has been no agreement between the parties, and Ecopetrol filed a lawsuit in the Contravention Administrative Tribunal in the District of Cauca (the "Tribunal") regarding this matter. During the first quarter of 2013, the Tribunal ruled in favor of Ecopetrol and awarded Ecopetrol 44,025 bbl of oil. GTEC has filed an appeal of the ruling to the Supreme Administrative Court (Consejo de Estado) in a second instance procedure. During the nine months ended September 30, 2013, based on market oil prices in Colombia, Gran Tierra accrued $4.4 million in the condensed consolidated financial statements in relation to this dispute.

Gran Tierra’s production from the Costayaco field is subject to an additional royalty that applies when cumulative gross production from a commercial field is greater than 5 MMbbl. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a non-compliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds 5 MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process and filed an arbitration claim. As at September 30, 2013, total cumulative production from the Moqueta field was 1.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH’s interpretation is successful is $31.7 million. At this time, no amount has been accrued in the condensed consolidated financial statements nor deducted from the Company's reserves as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra Colombia are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the additional royalty. Discussions with the ANH are ongoing. As at September 30, 2013, the estimated compensation which would be payable if the ANH’s interpretation is successful is $23.4 million. At this time, no amount has been accrued in the condensed consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

Letters of credit

At September 30, 2013, the Company had provided promissory notes totaling $49.6 million (December 31, 2012 - $34.2 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

9. Financial Instruments, Fair Value Measurements and Credit Risk

At September 30, 2013, the Company’s financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, accrued liabilities, and contingent consideration and contingent liability included in other long-term liabilities. The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. Contingent consideration, which relates to the acquisition of the remaining 30% working interest in certain properties in Brazil in October 2012, was recorded on the balance sheet at the acquisition date fair value based on the consideration expected to be transferred and discounted back to present value by applying an appropriate discount rate that reflected the risk factors associated with the payment streams. The discount rate used was determined at the time of measurement in accordance with accepted valuation methods. The contingent liability which relates to a dispute with Ecopetrol (Note 8) was based on the fair value of the amount awarded. The fair value of the contingent consideration and contingent liability is being remeasured at the estimated fair value at each reporting period with the change in fair value recognized as income or expense in operating income. The fair value of the contingent consideration was $1.1 million at September 30, 2013, and December 31, 2012. The fair value of the contingent liability was $4.4 million at

September 30, 2013. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments. At September 30, 2013, and December 31, 2012, the Company held no derivative instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. The fair value of the contingent consideration payable in connection with the Brazil acquisition was determined using Level 3 inputs at September 30, 2013, and December 31, 2012. The disclosure in the paragraph above regarding the fair value of other financial instruments is based on Level 1 inputs.

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

At September 30, 2013, cash and cash equivalents and restricted cash included balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with financial institutions with strong investment grade ratings or governments, or the equivalent in the Company’s operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in the Company’s operating areas.

Most of the Company’s accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company’s overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the nine months ended September 30, 2013, the Company had two customers which were significant to the Colombian segment, three customers which were significant to the Argentina segment and one customer which was significant to the Brazilian segment.

For the nine months ended September 30, 2013, 87% (nine months ended September 30, 2012 - 86%) of the Company's revenue and other income was generated in Colombia.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra’s current and deferred tax liabilities, which are monetary liabilities mainly denominated in the local currency of the Colombian foreign operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $95,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Argentina Central Bank may require prior authorization and may or may not grant such authorization for Gran Tierra's Argentina subsidiaries to make dividends or loan payments to the Company. During the three months ended June 30, 2013, the Company repatriated $11.1 million from one of its Argentina subsidiaries through loan repayments, authorized by the Argentina Central Bank. These were repayments of loan principal and as such had no withholding tax applied. At September 30, 2013, $20.3 million, or 6%, of the Company's cash and cash equivalents was deposited with banks in Argentina. We expect to use these funds for the Argentina work program and operations in 2013.

10. Credit Facilities

At September 30, 2013, a subsidiary of Gran Tierra 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 of up to $300 million and is supported by the present value of the petroleum reserves of two of the Company's subsidiaries with operating branches in Colombia and the Company's 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. Subsequent to the effective date, the

Company has not drawn down any amounts under the new credit facility. Under the terms of the facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility and, if the Company is not in default, then it is required to obtain bank approval for any dividend payments exceeding $2 million in any fiscal year.

11. Related Party Transactions

On August 7, 2012, Gran Tierra entered into a contract related to the Brazil drilling program with a company for which one of Gran Tierra’s directors is a shareholder and was a director. During the three and nine months ended September 30, 2013, $4.2 million and $11.8 million, respectively, (three and nine months ended September 30, 2012 - $nil) was incurred and capitalized under this contract. At September 30, 2013, $2.3 million (December 31, 2012 - $1.1 million) was included in accounts payable relating to this contract.

Item 2. 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 Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well as Part II, Item 1A "Risk Factors" in this Quarterly Report on Form 10-Q.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our Annual Report on Form 10-K, filed with the U.S. Securities and Exchange Commission ("SEC") on February 26, 2013.

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 with business units in Colombia, Argentina, Peru and Brazil, and we are headquartered in Calgary, Alberta, Canada. For the nine months ended September 30, 2013, 87% (nine months ended September 30, 2012 - 86%) of our revenue and other income was generated in Colombia.

Highlights

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| Production (BOEPD) (1) | 21,978 | 19,491 | 13 | 22,505 | 16,797 | 34 |
| Prices Realized - per BOE | $93.46 | $94.03 | (1) | $91.46 | $95.26 | (4) |
| Revenue and Other Income ($000s) | $189,658 | $168,933 | 12 | $563,839 | $440,034 | 28 |
| Net Income ($000s) | $33,057 | $44,605 | (26) | $138,753 | $57,396 | 142 |
| Net Income Per Share - Basic | $0.12 | $0.16 | (25) | $0.49 | $0.20 | 145 |
| Net Income Per Share - Diluted | $0.12 | $0.16 | (25) | $0.49 | $0.20 | 145 |
| Funds Flow From Operations ($000s) (2) | $84,546 | $89,935 | (6) | $284,659 | $206,511 | 38 |
| Net Capital Expenditures ($000s) (3) | $36,619 | $61,790 | (41) | $203,642 | $215,985 | (6) |

| | As at | | |
|---|---|---|---|
| | September 30, 2013 | December 31, 2012 | % Change |
| Cash & Cash Equivalents ($000s) | $353,064 | $212,624 | 66 |

| | | | |
|---|---|---|---|
| Working Capital (including cash & cash equivalents) ($000s) | $289,609 | $222,468 | 30 |
| Property, Plant & Equipment ($000s) | $1,234,376 | $1,205,426 | 2 |

25

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Funds Flow From Operations - Non-GAAP Measure ($000s) | 2013 | 2012 | 2013 | 2012 |
| Net income | $33,057 | $44,605 | $138,753 | $57,396 |
| Adjustments to reconcile net income to funds flow from operations | | | | |
| DD&A expenses | 58,875 | 45,044 | 180,309 | 137,982 |
| Deferred tax (recovery) expense | (8,042) | 1,195 | (23,791) | (8,855) |
| Stock-based compensation | 1,697 | 2,932 | 6,113 | 9,854 |
| Unrealized foreign exchange loss (gain) | 1,513 | (2,092) | (16,853) | 14,072 |
| Cash settlement of asset retirement obligation | (927) | — | (927) | (404) |
| Equity tax | (1,627) | (1,749) | (3,345) | (3,534) |
| Other loss | — | — | 4,400 | — |
| Funds flow from operations | $84,546 | $89,935 | $284,659 | $206,511 |

(3) In the third quarter of 2013, segment capital expenditures in Brazil are net of proceeds of $54.0 million relating to termination of a farm-in agreement. Additionally, segment capital expenditures for the nine months ended September 30, 2013, are net of proceeds of $4.1 million relating to the Company's assumption of the remaining 50% working interest in the Santa Victoria Block in Argentina and $1.5 million relating to the Company's sale of its 15% working interest in the Mecaya Block in Colombia.

- For the three and nine months ended September 30, 2013, oil and gas production, NAR and adjusted for inventory changes, increased by 13% to 21,978 BOEPD and by 34% to 22,505 BOEPD compared with the corresponding periods in 2012, respectively. In Colombia, alternative transportation arrangements to minimize the impact of pipeline disruptions, production from new wells and a decrease in oil inventory had a positive impact on production in 2013. In the three and nine months ended September 30, 2013, production was 75% from the Chaza Block in Colombia. In the three months ended September 30, 2013, the Puesto Morales and Surubi Blocks in Argentina contributed 7% and 4% of total production, respectively, and in the nine months ended September 30, 2013, their contribution was 8% and 5%, respectively.

- For the three and nine months ended September 30, 2013, revenue and other income increased by 12% to $189.7 million and by 28% to $563.8 million compared with $168.9 million and $440.0 million in the corresponding periods in 2012, respectively. The positive contribution from higher production levels was partially offset by lower realized prices. The average price realized per BOE decreased by 1% to $93.46 and by 4% to $91.46 for the three and nine months ended September 30, 2013, from $94.03 and $95.26, in the comparable periods in 2012, respectively.

Net income was $33.1 million, or $0.12 per share basic and diluted, and $138.8 million, or $0.49 per share basic and diluted, for the three and nine months ended September 30, 2013, respectively, compared with $44.6 million and $57.4 million, or $0.16 and $0.20 per share basic and diluted, in the corresponding periods in 2012, respectively. For the three months ended September 30, 2013, increased oil and natural gas sales were more than offset by increased DD&A, general and administrative ("G&A") and income tax expenses and foreign exchange losses. For the nine months ended September 30, 2013, increased oil and natural gas sales and foreign exchange gains and lower G&A expenses were partially offset by increased DD&A, operating and income tax expenses.

- For the three and nine months ended September 30, 2013, funds flow from operations decreased by 6% to $84.5 million and increased by 38% to $284.7 million, respectively. For the three months ended September 30, 2013, increased oil and natural gas sales were more than offset by increased G&A and income tax expenses. For the nine months ended September 30, 2013, increased oil and natural gas sales, lower G&A expenses and decreased realized foreign exchange losses were partially offset by increased operating and income tax expenses.

- Cash and cash equivalents were $353.1 million at September 30, 2013, compared with $212.6 million at December 31, 2012. The increase in cash and cash equivalents during the nine months ended September 30, 2013, was primarily the result of funds flow from operations of $284.7 million, a $64.4 million change in assets and liabilities from operating activities, partially offset by capital expenditures, net of proceeds from oil and gas properties, of $208.0 million.

- Working capital (including cash and cash equivalents) was $289.6 million at September 30, 2013, a $67.1 million increase from December 31, 2012.

- Property, plant and equipment at September 30, 2013, was $1.2 billion, an increase of $29.0 million from December 31, 2012, as a result of $203.6 million of net capital expenditures (net of proceeds from oil and gas properties of $59.6 million and excluding changes in non-cash working capital), partially offset by $174.6 million of depletion, depreciation and impairment expenses.

- Net capital expenditures for the nine months ended September 30, 2013, were $203.6 million compared with $216.0 million for the nine months ended September 30, 2012. In 2013, capital expenditures included drilling of $161.1 million, geological and geophysical ("G&G") expenditures of $56.9 million, facilities of $27.4 million and other expenditures of $17.8 million. Capital expenditures in 2013 were offset by proceeds from oil and gas properties of $59.6 million.

Business Environment Outlook

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

We believe that our current operations and 2013 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 downturn in oil and gas prices, we would examine measures such as capital expenditure program reductions, use of our existing revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. Continuing social and political uncertainty in the Middle East, North Africa and South America, economic uncertainty in the United States, Europe and Asia and changes in global supply and infrastructure are having an impact on world markets and we are unable to determine the impact, if any, these events may have on oil prices. 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.

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

Consolidated Results of Operations

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| (Thousands of U.S. Dollars) | | | | | | |
| Oil and natural gas sales | $188,974 | $168,616 | 12 | $561,935 | $438,406 | 28 |
| Interest income | 684 | 317 | 116 | 1,904 | 1,628 | 17 |
| | 189,658 | 168,933 | 12 | 563,839 | 440,034 | 28 |
| | | | | | | |
| Operating expenses | 35,588 | 36,295 | (2) | 108,505 | 88,115 | 23 |
| DD&A expenses | 58,875 | 45,044 | 31 | 180,309 | 137,982 | 31 |
| G&A expenses | 14,673 | 12,896 | 14 | 37,840 | 46,394 | (18) |
| Foreign exchange loss (gain) | 1,880 | (1,315) | 243 | (15,329) | 27,867 | (155) |
| Other loss | — | — | — | 4,400 | — | — |
| | 111,016 | 92,920 | 19 | 315,725 | 300,358 | 5 |
| | | | | | | |
| Income before income taxes | 78,642 | 76,013 | 3 | 248,114 | 139,676 | 78 |
| Income tax expense | (45,585) | (31,408) | 45 | (109,361) | (82,280) | 33 |
| Net income | $33,057 | $44,605 | (26) | $138,753 | $57,396 | 142 |
| | | | | | | |
| Production | | | | | | |
| | | | | | | |
| Oil and NGL's, bbl | 1,969,077 | 1,726,224 | 14 | 5,982,710 | 4,410,917 | 36 |
| Natural gas, Mcf | 317,834 | 401,783 | (21) | 968,518 | 1,148,440 | (16) |
| Total production, BOE (1) | 2,022,049 | 1,793,188 | 13 | 6,144,130 | 4,602,324 | 34 |
| | | | | | | |
| Average Prices | | | | | | |
| | | | | | | |
| Oil and NGL's per bbl | $95.28 | $96.75 | (2) | $93.26 | $98.42 | (5) |
| Natural gas per Mcf | $4.25 | $4.01 | 6 | $4.13 | $3.75 | 10 |
| | | | | | | |
| Consolidated Results of Operations per BOE | | | | | | |
| | | | | | | |
| Oil and natural gas sales | $93.46 | $94.03 | (1) | $91.46 | $95.26 | (4) |
| Interest income | 0.34 | 0.18 | 89 | 0.31 | 0.35 | (11) |
| | 93.80 | 94.21 | — | 91.77 | 95.61 | (4) |
| | | | | | | |
| Operating expenses | 17.60 | 20.24 | (13) | 17.66 | 19.15 | (8) |
| DD&A expenses | 29.12 | 25.12 | 16 | 29.35 | 29.98 | (2) |
| G&A expenses | 7.26 | 7.19 | 1 | 6.16 | 10.08 | (39) |
| Foreign exchange loss (gain) | 0.93 | (0.73) | 227 | (2.49) | 6.05 | (141) |
| Other loss | — | — | — | 0.72 | — | — |
| | 54.91 | 51.82 | 6 | 51.40 | 65.26 | (21) |
| | | | | | | |
| Income before income taxes | 38.89 | 42.39 | (8) | 40.37 | 30.35 | 33 |
| Income tax expense | (22.54) | (17.52) | 29 | (17.80) | (17.88) | — |
| Net income | $16.35 | $24.87 | (34) | $22.57 | $12.47 | 81 |

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

Net income for the three and nine months ended September 30, 2013, was $33.1 million and $138.8 million, respectively, compared with $44.6 million and $57.4 million in the comparable periods in 2012. On a per share basis, net income decreased to $0.12 per share basic and diluted for the three months ended September 30, 2013, from $0.16 per share basic and diluted in the corresponding period in 2012. For the nine months ended September 30, 2013, net income increased to $0.49 per share basic and diluted from $0.20 per share basic and diluted in the corresponding period in 2012.

For the three months ended September 30, 2013, increased oil and natural gas sales were more than offset by increased DD&A, G&A and income tax expenses and foreign exchange losses. For the nine months ended September 30, 2013, increased oil and natural gas sales and foreign exchange gains and lower G&A expenses were partially offset by increased DD&A, operating and income tax expenses.

Oil and NGL production for the three months ended September 30, 2013, increased to 2.0 MMbbl compared with 1.7 MMbbl in 2012. The increase was primarily due to new wells and the reduced impact of pipeline disruptions in Colombia as well as higher production in Brazil, partially offset by reduced production in Argentina.

Oil and NGL production for the nine months ended September 30, 2013, increased to 6.0 MMbbl compared with 4.4 MMbbl in 2012. The increase was due to the reduced impact of pipeline disruptions in Colombia, a decrease in oil inventory in the Ecopetrol S.A. ("Ecopetrol")-operated Trans-Andean oil pipeline (the "OTA pipeline”) and associated Ecopetrol owned facilities in the Putumayo Basin, and production from new wells in Colombia. The net inventory reduction accounted for 0.1 MMbbl or 230 BOPD of the production increase. In the three and nine months ended September 30, 2013, the impact of OTA pipeline disruptions on production was mitigated by selling a portion of our oil through trucking and an alternative pipeline.

Average realized oil prices decreased by 2% to $95.28 per bbl for the three months ended September 30, 2013, from $96.75 per bbl in the comparable period in 2012 and decreased by 5% to $93.26 per bbl for the nine months ended September 30, 2013, from $98.42 per bbl in the comparable period in 2012. Average Brent oil prices for the three and nine months ended September 30, 2013, were $110.27 and $108.45 per bbl, respectively, compared with $109.61 and $112.20 per bbl in the corresponding periods in 2012. WTI oil prices for the three and nine months ended September 30, 2013, averaged $105.80 and $98.14 per bbl, respectively, compared with $92.27 and $96.21 per bbl in the corresponding periods in 2012. During the three and nine months ended September 30, 2013, 38% and 39% of our oil and gas volumes sold in Colombia, respectively, 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 three months ended September 30, 2013, increased to $189.7 million from $168.9 million in the comparable period in 2012 as a result of increased production, partially offset by decreased realized prices. Revenue and other income for the nine months ended September 30, 2013, increased to $563.8 million from $440.0 million in the comparable period in 2012 due to the same factors.

Operating expenses decreased by 2% to $35.6 million and increased by 23% to $108.5 million for the three and nine months ended September 30, 2013, respectively, from the comparable periods in 2012. For the three months ended September 30, 2013, the decrease in operating expenses was primarily due to a decrease in the operating cost per BOE, partially offset by increased production. For the nine months ended September 30, 2013, a decrease in the operating cost per BOE was more than offset by increased production. On a per BOE basis, operating expenses decreased by 13% to $17.60 and 8% to $17.66 for the three and nine months ended September 30, 2013, respectively, from $20.24 and $19.15 in the comparable periods in 2012. 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 related to a 1,500 km route are paid by the purchaser and netted to arrive at our realized price.

DD&A expenses for the three months ended September 30, 2013, increased to $58.9 million from $45.0 million in the comparable period in 2012, due to increased production and an increased depletion rate. On a per BOE basis, the depletion rate increased by 16% to $29.12 from $25.12 due to increased costs in the depletable base only partially offset by increased reserves.

DD&A expenses for the nine months ended September 30, 2013, increased to $180.3 million from $138.0 million in the comparable period in 2012. The impact of increased production was partially offset by a reduction in ceiling test impairment losses. DD&A expenses for the nine months ended September 30, 2013, included a $2.0 million ceiling test impairment loss in our Brazil cost center. DD&A expenses for the nine months ended September 30, 2012, included a $20.2 million ceiling test impairment loss in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. On a per BOE basis, the depletion rate was consistent with the comparable period at $29.35. Reduced Brazil cost center impairment losses and increased reserves were offset by increased costs in the depletable base.

G&A expenses for the three months ended September 30, 2013, increased by 14% to $14.7 million from $12.9 million compared with the corresponding period in 2012. Increased employee related costs reflecting expanded operations and withholding tax on inter-company charges were partially offset by higher G&A allocations to operating expenses and capital projects within the business units. G&A expenses per BOE of $7.26 were consistent with the comparable period in 2012.

G&A expenses for the nine months ended September 30, 2013, decreased by 18% to $37.8 million from $46.4 million, compared with the corresponding period in 2012. Increased employee related costs reflecting expanded operations and withholding tax on inter-company charges were more than offset by higher G&A allocations to operating expenses and capital projects within the business units. G&A expenses per BOE of $6.16, were 39% lower compared with $10.08 in 2012 due to increased production and higher G&A allocations to operating expenses and capital projects within the business units.

For the three months ended September 30, 2013, the foreign exchange loss was $1.9 million and for the nine months ended September 30, 2013, the foreign exchange gain was $15.3 million. For the three months ended September 30, 2013, we had realized foreign exchange losses of $0.4 million and an unrealized non-cash foreign exchange loss of $1.5 million. For the nine months ended September 30, 2013, we had realized foreign exchange losses of $1.6 million and an unrealized non-cash foreign exchange gain of $16.9 million. The unrealized foreign exchange gain in the nine months ended September 30, 2013, was a result of a net monetary liability position in Colombia combined with the weakening of the Colombian Peso. This was partially offset by foreign exchange losses resulting from a net monetary asset position in Argentina and the weakening of the Argentina Peso.

For the three months ended September 30, 2012, there was a foreign exchange gain of $1.3 million, comprising a $2.1 million unrealized non-cash foreign exchange gain and realized foreign exchange losses of $0.8 million. For the nine months ended September 30, 2012, there was a foreign exchange loss of $27.9 million, comprising a $14.1 million unrealized non-cash foreign exchange loss and realized foreign exchange losses of $13.8 million. The unrealized non-cash foreign exchange loss was a result of a net monetary liability position in Colombia combined with the strengthening of the Colombian Peso. The realized foreign exchange loss primarily arose upon payment of the 2011 Colombian income tax liability during the second quarter of 2012.

Other loss of $4.4 million in the nine months ended September 30, 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.

Income tax expense was $45.6 million and $109.4 million for the three and nine months ended September 30, 2013, respectively, compared with $31.4 million and $82.3 million in the comparable periods 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 liability of approximately $10.4 million during the third quarter of 2013. The effective tax rate was 44% in the nine months ended September 30, 2013, compared with 59% in the comparable period in 2012. The change in the effective tax rate from the comparable period in 2012 was primarily due to a decrease in non-deductible foreign currency translation adjustments and other permanent differences, partially offset by an increase in the valuation allowance.

For the nine months ended September 30, 2013, the differential between the effective tax rate of 44% and the 35% U.S. statutory rate was primarily attributable to the increase in valuation allowance, a non-deductible third party royalty in Colombia and non-deductible foreign currency translation adjustments. The variance from the 35% U.S. statutory rate for 2012 was primarily attributable to the same factors as 2013.

2013 Work Program and Capital Expenditure Program

Our 2013 capital program has been revised to $420 million from $454 million. This includes: $218 million for Colombia; $89 million for Brazil; $25 million for Argentina; $87 million for Peru; and $1 million associated with corporate activities. The majority of the decrease in our capital spending is due to deferral of the following projects to 2014: facilities work on the Jilguero Block in Colombia; the Proa-3 well in Argentina; the long-term test on the

Bretaña Norte 95-2-1XD exploration well on Block 95 and the seismic program on Block 107 in Peru; and facilities work on Block REC-T-155 in Brazil. These decreases in 2013 capital spending where partially offset by new appraisal wells planned for Colombia. The capital spending program allocates $239 million for drilling; $58 million for facilities, pipelines and other; $108 million for G&G expenditures; $14 million for acquisitions; and $1 million for corporate activities. Of the $239 million allocated to drilling, approximately $119 million is for exploration and the balance is for appraisal and development drilling.

Our 2013 work program is intended to create both growth and value by developing existing assets to increase reserves and production levels, the construction of pipelines and facilities in the areas with proved reserves, and maturing our exploration prospects through seismic acquisition and drilling. We are financing our capital program through cash flows from operations 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, we regularly review our budgets with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds be expended as set forth in our 2013 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Segmented Results – Colombia

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| (Thousands of U.S. Dollars) | | | | | | |
| Oil and natural gas sales | $164,241 | $145,610 | 13 | $488,577 | $376,261 | 30 |
| Interest income | 111 | 171 | (35) | 415 | 598 | (31) |
| | 164,352 | 145,781 | 13 | 488,992 | 376,859 | 30 |
| Operating expenses | 23,463 | 27,005 | (13) | 75,764 | 61,200 | 24 |
| DD&A expenses | 46,821 | 35,255 | 33 | 141,141 | 90,625 | 56 |
| G&A expenses | 3,035 | 4,504 | (33) | 11,050 | 18,079 | (39) |
| Foreign exchange loss (gain) | 1,819 | (898) | 303 | (18,716) | 24,439 | (177) |
| Other loss | — | — | — | 4,400 | — | — |
| | 75,138 | 65,866 | 14 | 213,639 | 194,343 | 10 |
| Income before income taxes | $89,214 | $79,915 | 12 | $275,353 | $182,516 | 51 |
| Production | | | | | | |
| Oil and NGL's, bbl | 1,696,981 | 1,428,251 | 19 | 5,108,862 | 3,606,090 | 42 |
| Natural gas, Mcf | 39,648 | 76,770 | (48) | 50,116 | 144,930 | (65) |
| Total production, BOE (1) | 1,703,589 | 1,441,046 | 18 | 5,117,215 | 3,630,245 | 41 |
| Average Prices | | | | | | |
| Oil and NGL's per bbl | $96.72 | $101.81 | (5) | $95.60 | $104.23 | (8) |
| Natural gas per Mcf | $2.88 | $2.62 | 10 | $3.78 | $2.67 | 42 |
| Segmented Results of Operations per BOE | | | | | | |
| Oil and natural gas sales | $96.41 | $101.04 | (5) | $95.48 | $103.65 | (8) |
| Interest income | 0.07 | 0.12 | (42) | 0.08 | 0.16 | (50) |
| | 96.48 | 101.16 | (5) | 95.56 | 103.81 | (8) |
| Operating expenses | 13.77 | 18.74 | (27) | 14.81 | 16.86 | (12) |
| DD&A expenses | 27.48 | 24.46 | 12 | 27.58 | 24.96 | 10 |
| G&A expenses | 1.78 | 3.13 | (43) | 2.16 | 4.98 | (57) |
| Foreign exchange loss (gain) | 1.07 | (0.62) | 273 | (3.66) | 6.73 | (154) |
| Other loss | — | — | — | 0.86 | — | — |
| | 44.10 | 45.71 | (4) | 41.75 | 53.53 | (22) |
| Income before income taxes | $52.38 | $55.45 | (6) | $53.81 | $50.28 | 7 |

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

For the three and nine months ended September 30, 2013, income before income taxes was $89.2 million and $275.4 million, respectively, compared with $79.9 million and $182.5 million in the comparable periods in 2012. For the three months ended September 30, 2013, the increase was due to higher oil and natural gas sales as a result of higher production and decreased operating and G&A expenses, partially offset by increased DD&A expenses and foreign exchange losses. For the nine months ended September 30, 2013, the increase was due to higher oil and natural gas sales as a result of higher production, lower G&A expenses and higher foreign exchange gains, partially offset by increased DD&A and operating expenses.

Oil and NGL production for the three months ended September 30, 2013, increased to 1.7 MMbbl compared with 1.4 MMbbl in the comparable period in 2012 due to the reduced impact of pipeline disruptions, 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, partially offset by the end of the Melero field long-term test production. Production during the three months ended September 30, 2013, reflected approximately 35 days of oil delivery restrictions in Colombia compared with 36 days of oil delivery restrictions in the comparable period in 2012.

Oil and NGL production for the nine months ended September 30, 2013, increased to 5.1 MMbbl compared with 3.6 MMbbl in the comparable period in 2012 due to the reduced impact of pipeline disruptions, a decrease in oil inventory as previously discussed and increased production from new wells in the Costayaco and Moqueta fields in the Chaza Block. The net inventory reduction accounted for 0.1 MMbbl or 333 BOPD of the production increase. Production during the nine months ended September 30, 2013, reflected approximately 150 days of oil delivery restrictions in Colombia compared with 121 days of oil delivery restrictions in the comparable period 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 for the three and nine months ended September 30, 2013, increased by 13% to $164.4 million and 30% to $489.0 million, respectively, from the comparable periods in 2012.

For the three and nine months ended September 30, 2013, the average realized price per bbl for oil decreased by 5% to $96.72 and by 8% to $95.60, respectively, compared with $101.81 and $104.23, in the corresponding periods in 2012. Average Brent oil prices for the three and nine months ended September 30, 2013, were $110.27 and $108.45 per bbl, respectively, compared with $109.61 and $112.20 per bbl in the corresponding periods in 2012.

During the three and nine months ended September 30, 2013, 38% and 39% of our oil and gas volumes sold, respectively, were to a customer to which oil is delivered at the Costayaco battery and the sales price is based on average WTI prices plus a Vasconia differential and premium, adjusted for trucking costs related to a 1,500 km route. The effect on the Colombian realized price for the three and nine months ended September 30, 2013, was a reduction of approximately $7.61 and $8.47 per BOE as 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 $3.00 per BOE reduction in the average realized price in the nine months ended September 30, 2012.

Operating expenses decreased by 13% to $23.5 million for the three months ended September 30, 2013, and increased by 24% to $75.8 million for nine months ended September 30, 2013, from the comparable periods in 2012. On a per BOE basis, operating expenses decreased by 27% to $13.77 and 12% to $14.81 for the three and nine months ended September 30, 2013, respectively, from $18.74 and $16.86 in the comparable periods in 2012.

In the three months ended September 30, 2013, operating expenses 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 three months ended September 30, 2013, was a saving of $2.02 per BOE.

In the nine months ended September 30, 2013, lower transportation costs associated with OTA pipeline disruptions, were partially offset by increased G&A allocations to operating costs and increased other fixed costs. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the nine months ended September 30, 2013, was a saving of $1.36 per BOE.

DD&A expenses increased by 33% to $46.8 million and 56% to $141.1 million for the three and nine months ended September 30, 2013, respectively, from the comparable periods 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 12% to $27.48 and 10% to $27.58 for the three and nine months ended September 30, 2013, respectively. The increase was primarily due to increased costs in the depletable base, partially offset by an increase in reserves.

G&A expenses decreased by 33% to $3.0 million ($1.78 per BOE) from $4.5 million ($3.13 per BOE) and by 39% to $11.1 million ($2.16 per BOE) from $18.1 million ($4.98 per BOE) for the three and nine months ended September 30, 2013, respectively, from the comparable periods 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 the nine months ended September 30, 2013, compared with the comparable period in 2012 due to lower tax installment payments resulting from a corporate reorganization in Colombia in the fourth quarter of 2012.

For the three months ended September 30, 2013, the foreign exchange loss was $1.8 million, which included a $1.5 million unrealized non-cash foreign exchange loss. In the three months ended September 30, 2012, we had a foreign exchange gain of $0.9 million, which included a $2.2 million unrealized non-cash foreign exchange gain and a realized non-cash foreign exchange loss of $1.3 million. The Colombian Peso strengthened by 1% and weakened by 1% against the U.S. dollar in the three months ended September 30, 2013 and 2012, respectively. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation is the main source of the unrealized foreign exchange losses or gains.

For the nine months ended September 30, 2013, the foreign exchange gain was $18.7 million, which included a $16.9 million unrealized non-cash foreign exchange gain. In the nine months ended September 30, 2012, we incurred a foreign exchange loss of $24.4 million, of which $14.0 million was an unrealized non-cash foreign exchange loss. The realized foreign exchange loss in 2012 primarily arose upon payment of 2011 taxes. The Colombian Peso weakened by 8% and strengthened by 7% against the U.S. dollar in the nine months ended September 30, 2013 and 2012, respectively.

Other loss of $4.4 million in the nine months ended September 30, 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.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the three months ended September 30, 2013, were $39.6 million bringing total capital expenditures, for the nine months ended September 30, 2013, to $120.3 million. During the second quarter of 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 2013 and 2012:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (Millions of U.S. Dollars) | 2013 | 2012 | 2013 | 2012 |
| Drilling and completions | $22.9 | $23.1 | $62.6 | $63.5 |
| G&G | 8.6 | 3.3 | 25.2 | 9.5 |
| Facilities and equipment | 6.5 | 7.0 | 23.2 | 17.6 |
| Other | 1.6 | 2.5 | 9.3 | 7.9 |

| | | | | |
|---|---|---|---|---|
| | $39.6 | $35.9 | $120.3 | $98.5 |

The significant elements of our third quarter 2013 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Moqueta-11 development well in the Moqueta field as an oil producer and commenced drilling the Moqueta-12 development well.
- Together with our partner, we continued drilling the Mayalito-1 exploration well on the Llanos-22 Block (45% WI, non-operated).

- We continued civil construction for one gross exploration well, Miraflor Oeste, on the Guayuyaco Block (70% WI, operated).
- We started 2-D seismic on the Cauca-7 Block (100% WI, operated) and continued 3-D seismic on the Putumayo-1 Block (55% WI, operated).
- We also continued facilities work at the Costayaco and Moqueta fields on the Chaza Block.

Outlook - Colombia

The 2013 capital program in Colombia is $218 million with $113 million allocated to drilling, $43 million to facilities and pipelines and $62 million for G&G expenditures.

Our planned work program for the remainder of 2013 in Colombia includes drilling the Mayalito-1 exploration well on the Llanos-22 Block and the Miraflor Oeste exploration well on the Guayuyaco Block. Additionally, we plan to start civil construction for an additional exploration well on the Guayuyaco Block. We also plan to complete the Moqueta-12 development well, drill two appraisal wells, Corunta-1 and Zapotero-1, adjacent to the Moqueta field, and convert an existing well on the Garibay Block to a water injector well.

We also plan to acquire 2-D seismic on the Cauca-6 (100% WI, operated), Cauca-7 and Piedemonte Sur (100% WI, operated) Blocks and 3-D seismic on the Putumayo-1 Block. Facilities work is also planned for the Chaza, Garibay and the Llanos-22 Blocks.

Segmented Results – Argentina

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| (Thousands of U.S. Dollars) | | | | | | |
| Oil and natural gas sales | $18,149 | $22,332 | (19) | $54,620 | $59,183 | (8) |
| Interest income | 164 | 10 | — | 710 | 96 | 640 |
| | 18,313 | 22,342 | (18) | 55,330 | 59,279 | (7) |
| Operating expenses | 10,518 | 8,197 | 28 | 27,422 | 24,490 | 12 |
| DD&A expenses | 7,606 | 9,165 | (17) | 22,986 | 23,080 | — |
| G&A expenses | 2,899 | 2,258 | 28 | 7,891 | 7,268 | 9 |
| Foreign exchange loss | 1,454 | 945 | 54 | 3,214 | 1,873 | 72 |
| | 22,477 | 20,565 | 9 | 61,513 | 56,711 | 8 |
| (Loss) income before income taxes | $(4,164) | $1,777 | (334) | $(6,183) | $2,568 | (341) |
| Production | | | | | | |
| Oil and NGL's, bbl | 202,960 | 290,414 | (30) | 673,919 | 773,252 | (13) |
| Natural gas, Mcf | 278,186 | 325,013 | (14) | 918,402 | 1,003,510 | (8) |
| Total production, BOE (1) | 249,324 | 344,583 | (28) | 826,986 | 940,504 | (12) |
| Average Prices | | | | | | |
| Oil and NGL's per bbl | $83.09 | $72.05 | 15 | $75.20 | $71.48 | 5 |
| Natural gas per Mcf | $4.62 | $4.34 | 6 | $4.29 | $3.90 | 10 |
| Segmented Results of Operations per BOE | | | | | | |
| Oil and natural gas sales | $72.79 | $64.81 | 12 | $66.05 | $62.93 | 5 |
| Interest income | 0.66 | 0.03 | — | 0.86 | 0.10 | 760 |
| | 73.45 | 64.84 | 13 | 66.91 | 63.03 | 6 |
| Operating expenses | 42.19 | 23.79 | 77 | 33.16 | 26.04 | 27 |
| DD&A expenses | 30.51 | 26.60 | 15 | 27.79 | 24.54 | 13 |
| G&A expenses | 11.63 | 6.55 | 78 | 9.54 | 7.73 | 23 |
| Foreign exchange loss | 5.83 | 2.74 | 113 | 3.89 | 1.99 | 95 |
| | 90.16 | 59.68 | 51 | 74.38 | 60.30 | 23 |
| (Loss) income before income taxes | $(16.71) | $5.16 | (424) | $(7.47) | $2.73 | (374) |

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

For the three and nine months ended September 30, 2013, loss before income taxes in Argentina was $4.2 million and $6.2 million, respectively, compared with income before taxes of $1.8 million and $2.6 million in the comparable periods in 2012. In the three months ended September 30, 2013, decreased oil and natural gas sales and increased operating and G&A expenses and foreign exchange losses were partially offset by decreased DD&A expenses. In the nine months ended September 30, 2013, DD&A expenses were comparable to the prior year, but oil and natural gas sales decreased and operating and G&A expenses and foreign exchange losses increased.

Total oil and gas production from the Argentina segment decreased by 28% to 0.2 MMBOE for the three months ended September 30, 2013, and by 12% to 0.8 MMBOE for the nine months ended September 30, 2013, compared with the corresponding periods in 2012.

Oil and NGL production decreased by 30% to 0.2 MMbbl for the three months ended September 30, 2013 and decreased by 13% to 0.7 MMbbl for the nine months ended September 30, 2013, compared with the comparable periods in 2012. The decreases were primarily due to the following: reduced production from the Puesto Morales Block due to expected production declines, well downtime for workovers, and delays in the completion of the waterflood implementation due to ongoing analysis of a pilot project; 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.

Revenue and other income decreased by 18% to $18.3 million and by 7% to $55.3 million for the three and nine months ended September 30, 2013, respectively. During the three months ended September 30, 2013, we recognized $2.2 million, or $10.80 per bbl, upon the sale of some of our Petroleum Plus program credits. These credits are 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. We have an additional $3.3 million of Petroleum Plus program credits which we expect to monetize. Future sales of these credits will be recognized when realized, as a contingent gain.

In 2013, production decreases were partially offset by increased oil and natural gas prices. For the three and nine months ended September 30, 2013, the average realized price per bbl for oil increased by 15% to $83.09 and by 5% to $75.20, respectively, compared with $72.05 and $71.48, in the corresponding periods in 2012. As noted above, the impact of the sale of some of our Petroleum Plus program credits in the three months ended September 30, 2013, was $10.80 per bbl (nine months ended September 30, 2013 - $3.25). The prices we receive in Argentina are influenced by the Argentina regulatory regime. Currently, most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis.

Operating expenses increased by 28% to $10.5 million and increased by 12% to $27.4 million for the three and nine months ended September 30, 2013, respectively, from the comparable periods in 2012. On a per BOE basis, operating expenses increased by 77% to $42.19 and by 27% to $33.16 for the three and nine months ended September 30, 2013, respectively, from $23.79 and $26.04 in the comparable periods in 2012. The increase in operating costs on a per BOE basis was primarily due to
workover expenses being $9.15 and $2.60 per BOE higher for the three and nine months ended September 30, 2013, respectively, increased security and road maintenance expenses on the Puesto Morales and Surubi Blocks and reduced production volumes, partially offset by reduced transportation costs. In the three and nine months ended September 30, 2013, workovers were performed on the Puesto Morales, Surubi and El Chivil Blocks, whereas in the three and nine months ended September 30, 2012, workovers were performed on the Puesto Morales and Palmar Largo Blocks.

DD&A expenses decreased by 17% to $7.6 million for the three months ended September 30, 2013, compared with $9.2 million in the comparable period in 2012. DD&A expenses for the nine months ended September 30, 2013, were comparable with the corresponding period in 2012. On a per BOE basis, DD&A expenses increased by 15% to $30.51 and by 13% to $27.79 for the three and nine months ended September 30, 2013, respectively, from the comparable periods in 2012. The increases were due to increased costs in the depletable base, partially offset by increased reserves.

G&A expenses were $2.9 million ($11.63 per BOE) in the three months ended September 30, 2013, compared with $2.3 million ($6.55 per BOE) in the comparable period in 2012. The increase was primarily due to lower G&A allocations due to reduced capital activity. For the nine months ended September 30, 2013, G&A expenses were $7.9 million ($9.54 per BOE) compared with $7.3 million ($7.73 per BOE) in the comparable period in 2012 due to higher compensation costs and lower G&A allocations.

For the three and nine months ended September 30, 2013, foreign exchange losses were $1.5 million and $3.2 million, respectively, compared with $0.9 million and $1.9 million in the comparable periods in 2012. The losses primarily related to realized foreign exchange losses on monetary assets in Argentina during the period. The Argentina Peso weakened by 8% and 4% against the U.S. dollar in the three months ended September 30, 2013 and 2012, respectively and by 18% and 9% against the U.S. dollar in the nine months ended September 30, 2013 and 2012, respectively. The net monetary asset balance exposed to foreign exchange losses was higher in 2013 as compared with 2012 as a result of lower capital expenditures.

Capital Program - Argentina

Capital expenditures in the three months ended September 30, 2013, included drilling of $6.4 million, G&G expenditures of $0.7 million, facilities of $0.5 million and other expenditures of $0.5 million, resulting in capital expenditures of $8.1 million and bringing total net capital expenditures, net of proceeds received for oil and gas properties, for the nine months ended September 30, 2013, to $12.4 million.

In Argentina, during the third quarter of 2013, we commenced drilling a horizontal multi-stage fracture stimulated well into the Loma Montosa formation on the Puesto Morales Block to further evaluate this new play. Work on this well is currently suspended due to landowner blockades that prevent safe operations. We also completed workovers on wells on this block.

Outlook – Argentina

The 2013 capital program in Argentina is $25 million with $16 million allocated to drilling, $4 million to facilities and pipelines, and $5 million to G&G expenditures.

Our planned work program for the remainder of 2013 in Argentina includes workovers on existing wells and facilities work on the El Chivil Block.

Segmented Results – Peru

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| (Thousands of U.S. Dollars) | | | | | | |
| Interest income | $— | $— | — | $27 | $15 | 80 |
| Operating expenses | — | — | — | — | $161 | (100) |
| DD&A expenses | 73 | 68 | 7 | 272 | 1,174 | (77) |
| G&A expenses | 1,234 | 1,034 | 19 | 3,621 | 3,116 | 16 |
| Foreign exchange loss (gain) | 97 | (255) | 138 | 1,118 | (289) | 487 |
| | 1,404 | 847 | 66 | 5,011 | 4,162 | 20 |
| Loss before income taxes | $(1,404) | $(847) | 66 | $(4,984) | $(4,147) | 20 |

For the three and nine months ended September 30, 2013, loss before income taxes in Peru was $1.4 million and $5.0 million, respectively, compared with $0.8 million and $4.1 million in the comparable periods in 2012.The increase was primarily due to increased foreign exchange losses.

Capital Program – Peru

Capital expenditures in the three months ended September 30, 2013, were $11.1 million bringing total capital expenditures for the nine months ended September 30, 2013, to $59.9 million. Capital expenditures in three months ended September 30, 2013 included drilling and G&G expenditures of $7.5 million, facilities expenditures of $1.4 million and other expenditures of $2.2 million.

The significant elements of our third quarter 2013 capital program in Peru were:

•

On Block 95 (100% WI, operated), we completed a preliminary Front End Engineering Design ("FEED") study for the Bretaña field development and initiated a 2-D seismic program to provide a more detailed map of the Bretaña structure, along with maturing separate independent exploration leads on Block 95.

- On Block 107 (100% WI, operated), we continued work to obtain the necessary environmental and social permits for future seismic programs.

Outlook - Peru

The 2013 capital program in Peru is $87 million with $43 million allocated to drilling, $4 million for facilities and $40 million for G&G expenditures.

Our planned work program for the remainder of 2013 includes infill seismic on the Bretaña Norte field and other identified leads on Block 95, further FEED planning for the Bretaña Norte field development and continued work to obtain the necessary environmental and social permits for future drilling activities and seismic programs on this block.

Additionally, we plan to continue Environmental Impact Assessments on Block 107, Block 133, Block 123 and Block 129.

Segmented Results - Brazil

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| (Thousands of U.S. Dollars) | | | | | | |
| Oil and natural gas sales | $6,584 | $674 | 877 | $18,738 | $2,962 | 533 |
| Interest income | 281 | 40 | 603 | 292 | 607 | (52) |
| | 6,865 | 714 | 861 | 19,030 | 3,569 | 433 |
| Operating expenses | 1,607 | 1,093 | 47 | 5,319 | 2,264 | 135 |
| DD&A expenses | 4,129 | 305 | — | 15,143 | 22,379 | (32) |
| G&A expenses | 2,851 | 355 | 703 | 3,594 | 1,492 | 141 |
| Foreign exchange (gain) loss | (1,385) | 131 | — | (1,363) | 1,901 | (172) |
| | 7,202 | 1,884 | 282 | 22,693 | 28,036 | (19) |
| Loss before income taxes | $(337) | $(1,170) | (71) | $(3,663) | $(24,467) | (85) |
| Production (1) | | | | | | |
| Oil and NGL's, bbl | 69,136 | 7,559 | 815 | 199,929 | 31,575 | 533 |
| Average Prices | | | | | | |
| Oil and NGL's per bbl | $95.23 | $89.17 | 7 | $93.72 | $93.81 | — |
| Segmented Results of Operations per bbl | | | | | | |
| Oil and natural gas sales | $95.23 | $89.17 | 7 | $93.72 | $93.81 | — |
| Interest income | 4.06 | 5.29 | (23) | 1.46 | 19.22 | (92) |
| | 99.29 | 94.46 | 5 | 95.18 | 113.03 | (16) |
| Operating expenses | 23.24 | 144.60 | (84) | 26.60 | 71.70 | (63) |
| DD&A expenses | 59.72 | 40.35 | 48 | 75.74 | 708.76 | (89) |
| G&A expenses | 41.24 | 46.96 | (12) | 17.98 | 47.25 | (62) |
| Foreign exchange (gain) loss | (20.03) | 17.33 | (216) | (6.82) | 60.21 | (111) |
| | 104.17 | 249.24 | (58) | 113.50 | 887.92 | (87) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Loss before income taxes | $(4.88) | $(154.78) | (97) | $(18.32) | $(774.89) | (98) |

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

38

For the three months ended September 30, 2013, loss before income taxes was $0.3 million compared with loss before income taxes of $1.2 million in the comparable period in 2012. In the three months ended September 30, 2013, increased oil and natural gas sales and foreign exchange gains were partially offset by increased operating, DD&A and G&A expenses and a non-recoverable withholding tax payable on inter-company charges. For the nine months ended September 30, 2013, loss before income taxes was $3.7 million compared with $24.5 million in the comparable period in 2012. In the second quarter of 2013, we recorded a ceiling test impairment loss of $2.0 million relating to lower realized prices and an increase in estimate of operating costs. Loss before taxes in the first quarter of 2012 included a ceiling test impairment loss of $20.2 million relating to seismic and drilling costs on Block BM-CAL-10.

Oil and NGL production in Brazil is from the Tiê field in Block 155 in the onshore Recôncavo Basin. At September 30, 2013, we had three producing wells in this field compared with one producing well in the comparable periods in 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. This resulted in lower oil and natural gas sales in the third quarter of 2012 compared with the third quarter of 2013. We also increased our working interest in Block 155 from 70% to 100% in October 2012. 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. Subsequent to the quarter end, 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. This will affect our fourth quarter 2013 production in Brazil.

Revenue and other income increased to $6.9 million and $19.0 million, respectively, for the three and nine months ended September 30, 2013, compared with $0.7 million and $3.6 million in the comparable periods in 2012, primarily due to increased oil production volumes. Additionally, for the three months ended September 30, 2013, the average realized price per bbl for oil increased by 7% to $95.23. The price we receive in Brazil is at a discount to Brent due to refining and quality discounts.

Operating expenses increased to $1.6 million and $5.3 million, respectively, for the three and nine months ended September 30, 2013, compared with $1.1 million and $2.3 million in the comparable periods in 2012, due to higher production volumes. On a per bbl basis, operating expenses decreased to $23.24 for the three months ended September 30, 2013, from $144.60 per bbl and decreased to $26.60 for the nine months ended September 30, 2013, from $71.70, in the corresponding periods in 2012. Operating expenses per bbl decreased due to increased production, partially offset by increased costs for water disposal and slickline services.

DD&A expenses were $4.1 million ($59.72 per bbl) and $15.1 million ($75.74 per bbl) in the three and nine months ended September 30, 2013, respectively, compared with $0.3 million ($40.35 per bbl) and $22.4 million ($708.76 per bbl) in the comparable periods in 2012. The increase in DD&A expenses per bbl in the three months ended September 30, 2013 compared with 2012 was due to 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. In the second quarter of 2013, we recorded a ceiling test impairment loss of $2.0 million as discussed earlier. DD&A expenses in the nine months ended September 30, 2012, included a ceiling test impairment loss of $20.2 million relating to seismic and drilling costs on Block BM-CAL-10, as discussed earlier.

G&A expenses were $2.9 million ($41.24 per bbl) and $3.6 million ($17.98 per bbl) in the three and nine months ended September 30, 2013, respectively, compared with $0.4 million ($46.96 per bbl) and $1.5 million ($47.25 per bbl) in the comparable periods in 2012. The increase in G&A expenses was due to non-recoverable withholding tax payable on inter-company charges.

Capital Program – Brazil

During the third quarter of 2013, we received a net payment of $54.0 million (before income taxes) from a third party in connection with termination of a farm-in agreement in the Recôncavo Basin relating to Block REC-T-129, Block REC-T-142, Block REC-T-155 and Block REC-T-224. We retain a 100% WI in these blocks.

We successfully bid on three blocks in the 2013 Brazil Bid Round administered by Brazil's Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") and, in the third quarter of 2013, paid a signature bonus of $14.4 million upon finalization of the concession agreements. The three blocks, Block REC-T-86, Block REC-T-117 and Block REC-T-118, are located north of our core existing areas in the Recôncavo Basin onshore Brazil and we hold a 100% operated WI in these blocks.

Capital expenditures in our Brazilian segment in the three months ended September 30, 2013, included drilling of $14.7 million, facilities of $0.4 million, G&G expenditures of $14.5 million and $1.9 million of other expenditures, resulting in capital expenditures recovery, net of the termination payment received, of $22.5 million, bringing net capital expenditures for the nine months ended September 30, 2013, to $12.0 million.

The significant elements of our third quarter 2013 capital program in Brazil were:

- On Block REC-T-155 (100% WI, operated), we drilled an exploration well, 1-GTE-8DP-BA. We met our primary objective which was to cut and retrieve core from the target interval. In the end, 144 feet of core was successfully retrieved which will be utilized for detailed special core analysis studies to gain critical information regarding the oil shale play. This wellbore is currently suspended awaiting fracture stimulation. We also drilled a horizontal sidetrack oil exploration well, 1-GTE-7HPC-BA, from the 1-GTE-7-BA wellbore. This well reached total depth during the third quarter of 2013, however, the wellbore is currently suspended awaiting fracture stimulation.
- On Block REC-T-129 (100% WI, operated), we continued work in preparation for re-entry and isolating the final two fracture stages at the horizontal sidetrack oil exploration well, 1-GTE-6HP-BA.

Outlook – Brazil

The 2013 capital program in Brazil is $89 million with $67 million allocated to drilling, $7 million to facilities and pipelines, $14 million for acquisitions and $1 million for G&G and other expenditures.

Our planned work program for the remainder of 2013 in Brazil includes fracture stimulations on the 1-GTE-7HPC-BA horizontal sidetrack oil exploration well and the the 1-GTE-8DP-BA oil exploration well on Block REC-T-155 and additional completion work on the 1-GTE-6-BA well on Block REC-T-129 and the 3-GTE-3-BA and 3-GTE-4-BA producing wells in the Tiê field. We also plan to perform facilities and pipeline work on Block REC-T-155.

Results - Corporate Activities

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2013 | 2012 | % Change | 2013 | 2012 | % Change |
| (Thousands of U.S. Dollars) | | | | | | |
| Interest income | $128 | $96 | 33 | $460 | $312 | 47 |
| | | | | | | |
| DD&A expenses | 246 | 251 | (2) | 767 | 724 | 6 |
| G&A expenses | 4,651 | 4,745 | (2) | 11,682 | 16,439 | (29) |
| Foreign exchange (gain) loss | (102) | (1,238) | (92) | 420 | (57) | (837) |
| | 4,795 | 3,758 | 28 | 12,869 | 17,106 | (25) |
| | | | | | | |
| Loss before income taxes | $(4,667) | $(3,662) | 27 | $(12,409) | $(16,794) | (26) |

G&A expenses in the three and nine months ended September 30, 2013, were $4.7 million and $11.7 million, respectively, compared with $4.7 million and $16.4 million in the comparable periods in 2012. G&A expenses for the three months ended September 30, 2013, were consistent with the comparable period in 2012. For the nine months ended September 30, 2013, the decrease in G&A expenses was primarily due to an increase in costs recovered from business units, lower stock-based compensation expense and compensation for damages. During the nine months ended September 30, 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 the period. Stock-based compensation expense decreased due to less residual amortization of prior year higher value stock-based payment awards in the 2013 and lower amortization of current year awards due to a later grant date than in 2012.

Liquidity and Capital Resources

At September 30, 2013, we had cash and cash equivalents of $353.1 million compared with $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 2013, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc., in interest earning current accounts or are invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At September 30, 2013, 94% of our cash and cash equivalents was generally not available to fund domestic or head office operations unless funds are repatriated, because it was held by subsidiaries and partnerships outside of Canada and the United States. During the three months ended June 30, 2013, we repatriated $11.1 million to a Canadian subsidiary from one of our Argentina subsidiaries through loan repayments, authorized by the Argentina Central Bank. These were repayments of loan principal and as such had no withholding tax applied. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The governments in Brazil and Argentina require us to register funds that enter and exit the country with the central bank in each country. In Brazil, Argentina and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in the Special Exchange Regime, which allows us to receive revenue in U.S. dollars offshore. Beginning in 2013, transfer 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.

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Argentina Central Bank may require prior authorization and may or may not grant such authorization for our Argentina subsidiaries to make dividends or loan payments to us. At September 30, 2013, $20.3 million, or 6%, of our cash and cash equivalents was deposited with banks in Argentina, after the above noted repatriation of $11.1 million during the second quarter of 2013. We expect to use these funds for the Argentina work program and operations in 2013.

At September 30, 2013, 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 current borrowing base of $150 million and a maximum borrowing base up to $300 million and 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. Subsequent to the effective date, we have not drawn down any amounts under the new credit facility. 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 million in any fiscal year.

Cash Flows

During the nine months ended September 30, 2013, our cash and cash equivalents increased by $140.4 million as a result of cash provided by operating activities of $349.1 million and cash provided by financing activities of $3.5 million, partially offset by cash used in investing activities of $212.1 million. During the nine months ended September 30, 2012, our cash and cash equivalents decreased by $224.1 million as a result of cash provided by operating activities of $15.9 million and cash provided by financing activities of $3.8 million, partially offset by cash used in investing activities of $243.8 million.

Cash provided by operating activities in the nine months ended September 30, 2013, was primarily affected by increased oil and natural gas sales, decreased G&A expenses, lower realized foreign exchange losses and a $64.4 million decrease 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 increased by $26.3 million primarily due to higher production in Colombia, partially offset by the impact of a reduction in the number of days of sales outstanding in Argentina; inventory decreased by $12.4 million primarily due to the reduced oil inventory in the OTA pipeline and associated Ecopetrol owned 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 $7.6 million due to the timing of payments for drilling activity; and net taxes receivable decreased by $87.2 million resulting in net taxes payable due to the reimbursement of a value added tax receivable and increased taxable income in Colombia.

Cash provided by operating activities in the nine months ended September 30, 2012, was affected by increased operating expenses and realized foreign exchange losses and a $190.6 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $96.7 million due to increased oil and gas sales and the timing of collection of receivables; inventory increased by $9.8 million due to a change in sales point under a new sales agreement in Colombia; accounts payable and accrued liabilities decreased by $26.0 million; and taxes payable decreased by $59.3 million due to tax payments in Colombia. The decrease in accounts payable and accrued liabilities was primarily the result of a reduction in royalties payable due to the timing of royalty payments and a reduction in value added tax payable.

Cash outflows from investing activities in the nine months ended September 30, 2013, included capital expenditures of $267.6 million (including changes in non-cash working capital related to investing activities) and an increase in restricted cash of $4.1 million and were partially offset by proceeds from oil and gas properties of $59.6 million. Cash outflows from investing activities in the nine months ended September 30, 2012, included capital expenditures of $222.1 million (including changes in non-cash working capital related to investing activities) and an increase in restricted cash of $21.7 million.

Cash provided by financing activities in the nine months ended September 30, 2013 and 2012, related to proceeds from issuance of shares of Common Stock upon the exercise of stock options.

## Off-Balance Sheet Arrangements

As at September 30, 2013, we had no off-balance sheet arrangements.

## Related Party Transactions

On August 7, 2012, we entered into a contract related to the Brazil drilling program with a company for which one of our directors is a shareholder (less than 10% shareholding) and was a director. During the nine months ended September 30, 2013, $11.8 million was incurred and capitalized under this contract and at September 30, 2013, $2.3 million (December 31, 2012 -$1.1 million) was included in accounts payable relating to this contract.

## Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2012 Annual Report on Form 10-K, filed with the SEC on February 26, 2013, and have not changed materially since the filing of that document.

## Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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

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

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $95,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar. For the nine months ended September 30, 2013, our realized foreign exchange loss was $1.6 million (nine months ended September 30, 2012 - $13.8 million). In 2013, the realized foreign exchange loss primarily related to foreign exchange losses on the net monetary assets in Argentina during the period. The Argentina Peso weakened by 18% and 9% against the U.S. dollar in the nine months ended September 30, 2013, and 2012, respectively. In 2012, the realized foreign exchange loss primarily arose upon payment of the 2011 Colombian income tax liability during the second quarter of 2012.

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

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of September 30, 2013, to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - Other Information

Item 1. Legal Proceedings

Gran Tierra’s production from the Costayaco field is subject to an additional royalty that applies when cumulative gross production from a commercial field is greater than five MMbbl. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra's view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process and filed an arbitration claim. As at September 30, 2013, total cumulative production from the Moqueta field was 1.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $31.7 million. At this time, no amount has been accrued in the financial statements nor deducted from our reserves for the disputed royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra Energy Colombia, Ltd are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the additional royalty. Discussions with the ANH are ongoing. As at September 30, 2013, the estimated compensation which would be payable if the ANH’s interpretation is successful is $23.4 million. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

Item 1A. Risk Factors

The risks relating to our business and industry, as set forth in our Annual Report on Form 10-K for the year ended December 31, 2012, filed with the Securities and Exchange Commission on February 26, 2013, are set forth below and are unchanged substantively at September 30, 2013, other than those designated by an asterisk “*”.

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 extending into the first ten months of 2013, guerrilla activity in Colombia increased significantly. This increased activity creates a greater risk for our operations and our employees and our mitigation activities may not be adequate to alleviate the risks arising from such guerrilla activity.

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

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Catatumbo, Cauca, Llanos, 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 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 November 2013. In the nine months ended September 30, 2013, the OTA pipeline was shutdown for approximately 150 days. 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 the first nine months of 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. Also during this time period, four workers employed by companies providing services to Gran Tierra in the Putumayo Basin were abducted, possibly by guerrillas. All were returned safely within two days. No Gran Tierra employees were involved. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

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

Our business focuses on the oil and gas industry in a limited number of properties in Colombia, Argentina, Peru, and Brazil. Most of our production is in one basin in Colombia and two basins in Argentina. As a result, we lack diversification, in terms of both the nature and geographic scope of our business. Accordingly, factors affecting our industry or the regions in which we operate, including the geographic remoteness of our operations and weather conditions, will likely impact us more acutely than if our business was more diversified. In particular, most of our production is from the Putumayo Basin in Colombia, and we depend on the OTA pipeline 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" could harm our business in Colombia and other countries.

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

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

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

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

Recent alternative transportation arrangements in Colombia allowed us to deliver our full production until September 2013; 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.

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

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

Oil sales in Colombia are mainly to Ecopetrol and, in the first, second and third quarters of 2013, to another customer. While oil prices in Colombia are related to international market prices, lack of competition and reliance on a limited number of customers for sales of oil may diminish prices and depress our financial results.

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

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

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

We operate our business in Colombia, Argentina, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as privatization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. For example, starting on November 21, 2008, we were forced to reduce production in Colombia on a gradual basis, culminating on December 11, 2008, when we suspended all production from the Santana, Guayuyaco and Chaza blocks in the Putumayo Basin. This temporary suspension of production operations was the result of a declaration of a state of emergency and force majeure by Ecopetrol due to a general strike in the region. In January 2009, the situation was resolved and we were able to resume production and sales shipments. Starting in 2010, there was an increased presence of illegitimate unionization activities in the Putumayo Basin by the Sindicato de Trabajadores Petroleros del Putumayo, which disrupted our operations from time to time and may do so in the future. During 2011 and 2012, Argentina has experienced increased union activity and this may create disruptions in our Argentina operations in the future. During 2012 and 2013, we have also experienced related issues with landowners blocking access to our fields in Argentina. 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. We do not know how long such labor action will last, and if it lasts a significant amount of time, it may effect 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 Argentina, Colombia, Peru or Brazil or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

At September 30, 2013, 94% of our cash and cash equivalents was generally not available to fund domestic or head office operations unless funds are repatriated, because it was held by subsidiaries and partnerships outside of Canada and the United States. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings.

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

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

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

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

Our capital program for 2013 calls for approximately $420 million to fund our exploration and development, which we intend to fund through existing cash on hand and cash flows from operations at current production and commodity price levels. Funding this program relies in part on oil prices remaining high and other factors to generate sufficient cash flow. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our business plan which would cause us to decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

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

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

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

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

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

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

Disputes or Uncertainties May Arise in Relation to our Royalty Obligations

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

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

The ANH has requested that the additional compensation be paid with respect to production from the recently drilled wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, we view the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have sent notice to the ANH to initiate the dispute resolution process prescribed by the Chaza Contract and have filed an arbitration claim. No assurance can be made that our interpretation will prevail and, depending on the ultimate size of the cumulative production from the Moqueta field in the future, such amounts may be material if such additional compensation must be paid. As at September 30, 2013, total cumulative production from the Moqueta field was 1.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $31.7 million. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra Energy Colombia, Ltd are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the additional royalty. Discussions with the ANH are ongoing. As at September 30, 2013, the estimated compensation which would be payable if the ANH's interpretation is successful is $23.4 million. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

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

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

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

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

Currently most oil and gas producers in Argentina are operating without sales contracts. In 2008, a new withholding tax regime for exports was introduced without specific guidance as to its application. The domestic price was regulated in a similar way, so that both exported and domestically sold products were priced the same. Producers and refiners of oil in Argentina were unable to determine an agreed sales price for oil deliveries to refineries. In our case, the refineries' price offered to oil producers reflects their price received, less taxes and operating costs and their usual mark up. Along with most other oil producers in

Argentina, we are continuing negotiating sales on a spot price basis with refiners and the price is negotiated on a month by month basis. The Provincial governments have also been hurt by these changes as their effective royalty and turnover tax takes have been reduced and capital investment in oilfields has declined, and so they are lobbying to change the situation. The government introduced the Petro Plus and Gas Plus programs in 2009, which grant higher prices to producers that sell production from new reserves. This is a positive step forward that will hopefully lead to further opening of price regulation in Argentina.

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

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

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

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

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

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

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

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

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. Our production in Argentina is primarily invoiced in U.S. dollars, but payment is made in Argentina pesos, at the then current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Since we began operating in Argentina (September 1, 2005), the rate of exchange between the Argentina peso and U.S. dollar has varied between 3.05 pesos to one U.S. dollar to 5.84 pesos to the U.S. dollar, a fluctuation of approximately 91%. Production in Brazil is invoiced and paid in Brazilian Reals. Since September 1, 2005, the exchange rate of the Brazilian Real has varied between 1.56 Reals to one U.S. dollar to 2.45 Reals to the U.S. dollar, a variance of 57%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the weakening of 8% in the Colombian Peso against the U.S. dollar in the nine months ended September 30, 2013, resulted in a foreign exchange gain.

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 be careful to invest carefully in projects that will truly benefit these areas. Improper management of these investments and relationships could lead to a delay in operations, loss of license or major impact to our reputation in these communities, which could adversely affect our business.

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

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

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

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

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

The governments in Brazil and Argentina require us to register funds that enter and exit the country with the central bank in each country. In Brazil, Argentina and Colombia, all transactions must be carried out in the local currency of the country. Exchange controls may prevent us from transferring funds abroad. For example, the Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentina subsidiaries to make dividend or loan payments to us and there may be a tax imposed with respect to the expatriation of such proceeds. During the three months ending June 30, 2013, we repatriated $11.1 million to a Canadian subsidiary from one of our Argentina subsidiaries through loan repayments, authorized by the Argentina Central Bank. These were repayments of loan principal and as such had no withholding tax applied.

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

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

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

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

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

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

- the President of the United States and Congress would retain the right to apply future trade sanctions.

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

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

We May 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.

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

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

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

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

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

The Shining Path Guerilla group has been active in Peru since the early 1980’s and, at one point, was active throughout the country. Recently, the group’s activity has been confined to small areas of Peru and operations have been hampered by the capture of many high profile leaders and membership has fallen dramatically. During April 2012, 30 people working on the

Camisea natural gas project in central Peru were kidnapped. Most of the workers were released after a short period of time, and the remainder were freed within a few days. The kidnapping was attributed to the Shining Path Guerilla group. Camisea is a very large, high profile project in an area where the group continues to be active. Our operations in Peru are in a different region, with no known activity by the group. Other groups may be active in other areas of the country and possibly our operational areas. We are monitoring the situation and increasing security measures as required. Nevertheless, we are concerned about the security of our operations in Peru and mitigate our risks through good relationships with local communities and stakeholders as well as strong security procedures.

*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. In June 2013, the City of Calgary experienced flooding which caused power outages throughout the city. As a result, many of our key information systems were unavailable for two business days. We have implemented strategies to improve our ability to keep our systems functioning through a similar disaster.

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.

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

We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. For example, the permitting process in Peru takes significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere. Other drilling and development projects are being delayed, most significantly our Moqueta field development, because the Ministry of the Environment has not increased staffing levels to meet increased activity in the oil and gas industry in Colombia and so permit processing takes longer than usual. These delays are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations. For example, currently in Brazil, we are subject to restrictions on flaring natural gas, which have the impact of limiting our production capacity. Additionally in Brazil, the exploration phase of three of our concession agreements is due to expire on November 24, 2013.We have submitted an application to the ANP for extensions of the exploration phase of these concession agreements as provided for in the agreements; however, we may not be successful and loss of these agreements may impair our ability to grow our business in Brazil.

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

Oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our exploration expenditures may not result in new discoveries of oil or natural gas in commercially viable quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations.

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

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

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

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

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

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

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

In 2011, we recorded a ceiling test impairment loss of $42.0 million in our Peru cost center related to seismic and drilling costs on two blocks which were relinquished and a ceiling test impairment loss of $25.7 million in our Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. In 2012, we recorded a ceiling test impairment loss of $20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. The farm-out agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period. In 2013, we recorded a ceiling test impairment loss of $2.0 million in our Brazil cost center related to lower realized prices and an increase in operating 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, the Valle Morado GTE.St.VMor-2001 re-entry operations started in the third quarter of 2010, with integrity testing and remediation operations required for the sidetrack operations. Due to operational difficulties, the initial side-track attempt was not successful. The operation was placed on standby pending the arrival of additional side-track equipment and operations recommenced in the fourth quarter of 2010. In February 2011, these operations were suspended and the wellbore has been abandoned due to a number of operational challenges encountered. We continue to review alternatives associated with the field development. Also for example, on February 7, 2009, we experienced an incident at our Juanambu-1 well, involving a fire in a generator, resulting in total damage to equipment estimated at $500,000, and production in the amount of approximately $125,000 being deferred due to shutting down production facilities while dealing with the incident. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. Incidents such as these can lead to serious injury, property damage and even loss of life. We generally obtain insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

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

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for WTI per bbl was $66 in 2006, $72 in 2007, $100 in 2008, $62 in 2009, $79 in 2010, $95 in 2011, $94 in 2012 and $98 in the nine months ended September 30, 2013, demonstrating the inherent volatility in the market. The average Brent oil price per bbl was $112 in 2012 and $108 in the nine months ended September 30, 2013. Given the current economic environment and unstable conditions in the Middle East, North Africa, the United States and Europe, 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 and quantities of reserves recoverable on an economic basis.

In addition, oil and natural gas prices in Argentina are effectively regulated and during 2009, 2010, 2011, 2012 and the nine months ended September 30, 2013, were substantially lower than those received in North America. Oil prices in Colombia are related to international market prices, but adjustments that are defined by contract with Ecopetrol, the purchaser of most of the oil that we produce in Colombia, may cause realized prices to be lower or higher than those received in North America. Oil prices in Brazil are defined by contract with the refinery and may be lower or higher than those received in North America.

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

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

Penalties We May Incur Could Impair Our Business.

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

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

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

Environmental Risks May Adversely Affect Our Business.

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

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

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

Challenges to Our Properties May Impact Our Financial Condition.

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

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

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

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

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

Risks Related to Our Common Stock

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

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

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

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

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

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

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

We do not intend to declare dividends for the foreseeable future, as we anticipate that we will reinvest any future earnings in the development and growth of our business. Therefore, investors will not receive any funds unless they sell their shares of

Common Stock, and shareholders may be unable to sell their shares on favorable terms or at all. Investors cannot be assured of a positive return on investment or that they will not lose the entire amount of their investment in shares of our Common Stock.

Item 6. Exhibits

See Index to Exhibits at the end of this Report, which is incorporated by reference here. The Exhibits listed in the accompanying Index to Exhibits are filed as part of this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GRAN TIERRA ENERGY INC.

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| Date: November 8, 2013 | /s/ Dana Coffield<br>By: Dana Coffield<br>Chief Executive Officer and President<br>(Principal Executive Officer) |
| Date: November 8, 2013 | /s/ James Rozon<br>By: James Rozon<br>Chief Financial Officer<br>(Principal Financial and Accounting Officer) |

EXHIBIT INDEX

| Exhibit No. | Description | Reference |
|---|---|---|
| 2.1 | Arrangement Agreement, dated as of July 28, 2008, by and among Gran Tierra Energy Inc., Solana Resources Limited and Gran Tierra Exchangeco Inc. | Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (SEC File No. 001-34018), filed with the SEC on August 1, 2008. |
| 2.2 | Amendment No. 2 to Arrangement Agreement, which supersedes Amendment No. 1 thereto and includes the Plan of Arrangement, including appendices. | Incorporated by reference to Exhibit 2.2 to the Registration Statement on Form S-3 (SEC File No. 333-153376), filed with the SEC on October 10, 2008. |
| 2.3 | Arrangement Agreement, dated January 17, 2011, by and between Gran Tierra Energy Inc. and Petrolifera Petroleum Limited. + | Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (SEC File No. 001-34018). |
| 3.1 | Amended and Restated Articles of Incorporation. | Incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q/A (SEC File No. 001-34018), filed with the SEC on January 6, 2010. |
| 3.2 | Amended and Restated Bylaws of Gran Tierra Energy Inc. | Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed with the SEC on February 27, 2013 (SEC File No. 000-52594). |
| 4.1 | Reference is made to Exhibits 3.1 to 3.2. | |
| 4.2 | Details of the Goldstrike Special Voting Share. | Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656). |
| 4.3 | Goldstrike Exchangeable Share Provisions. | Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656). |
| 4.4 | Provisions Attaching to the GTE–Solana Exchangeable Shares. | Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the SEC on October 14, 2008 (SEC File No. 001-34018). |
| 10.1 | Addendum No. 4 to the Transportation Agreement between Petrolifera Petroleum (Colombia) Ltd. and Ecopetrol S.A. | Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed with the SEC on August 7, 2013 (SEC File No. 333-111656). |
| 10.2 | Addendum No. 4 to the Transportation Agreement between Gran Tierra Energy Colombia, Ltd. and Ecopetrol S.A. | Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the SEC on August 7, 2013 (SEC File No. 333-111656). |

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| 10.3 | Credit Agreement, dated as of August 30, 2013, among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., the Lenders party thereto, and Wells Fargo Bank, National Association. | Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on September 6, 2013 (SEC File No. 001-34018). |
| 10.4 | Crude Oil Transportation Agreement for the Orito to Tumaco (OTA) pipeline, dated as of August 31, 2013, between Gran Tierra Energy Colombia, Ltd. and Cenit Transporte y Logística de Hidrocarburos S.A.S. | Filed herewith. |
| 10.5 | Crude Oil Transportation Agreement for the Orito to Tumaco (OTA) pipeline, dated as of August 31, 2013, between Petrolifera Petroleum (Colombia) Ltd. and Cenit Transporte y Logística de Hidrocarburos S.A.S. | Filed herewith. |

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| 10.6 | Crude Oil Transportation Agreement for the Mansoyá - Orito (OMO) pipeline, dated as of August 31, 2013, between Gran Tierra Energy Colombia, Ltd. and Cenit Transporte y Logística de Hidrocarburos S.A.S. | Filed herewith. |
| 10.7 | Crude Oil Transportation Agreement for the Mansoyá - Orito (OMO) pipeline, dated as of August 31, 2013, between Petrolifera Petroleum (Colombia) Ltd. and Cenit Transporte y Logística de Hidrocarburos S.A.S. | Filed herewith. |
| 31.1 | Certification of Principal Executive Officer. | Filed herewith. |
| 31.2 | Certification of Principal Financial Officer. | Filed herewith. |
| 32.1 | Section 1350 Certifications. | Filed herewith. |
| 101.INS | XBRL Instance Document | |
| 101.SCH | XBRL Taxonomy Extension Schema Document | |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document | |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document | |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document | |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document | |

+ Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Gran Tierra undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.