GRAN TIERRA ENERGY INC.
Form 10-Q
May 06, 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 March 31, 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 April 30, 2013, the following number of shares of the registrant's capital stock were outstanding: 269,577,263 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 6,223,810 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 6,840,062 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Three Months Ended March 31, 2013

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STATEMENT 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. Farm-in or farm-out transactions refer to transactions in which a portion of a working interest is sold by an owner of an oil and gas property. The transaction is labeled a farm-in by the purchaser of the working interest and a farm-out by the seller of the working interest. Payment in a farm-in or farm-out transaction can be in cash or in kind by committing to perform and/or pay for certain work obligations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ii.

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

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

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

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

i. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

ii. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

iii. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

iv. The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

v. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

vi. Pursuant to paragraph (a)(22)(iii) of section 210.4-10(a) of Regulations S-X, where direct observation has defined a HKO elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

- Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

- Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

- Probabilistic estimate. The method of estimating reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience, engineering or economic data) is used to generate a full range of possible outcomes and their associated probabilities of occurrences.

- Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

i. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; and

ii. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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- Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

i. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

ii. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

iii. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of section 201.4-10(a) of Regulation S-X, or by other evidence using reliable technology establishing reasonable certainty.

PART I - 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 March 31,	
	2013	2012
REVENUE AND OTHER INCOME		
Oil and natural gas sales	$204,780	$155,248
Interest income	591	703
	205,371	155,951
EXPENSES		
Operating	41,015	24,487
Depletion, depreciation, accretion and impairment (Note 4)	58,412	60,367
General and administrative	11,421	15,899
Foreign exchange (gain) loss	(5,229)	24,375
Other loss (Note 8)	4,400	—
	110,019	125,128
INCOME BEFORE INCOME TAXES	95,352	30,823
Income tax expense (Note 7)	(37,439)	(31,136)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	57,913	(313)
RETAINED EARNINGS, BEGINNING OF PERIOD	284,673	185,014
RETAINED EARNINGS, END OF PERIOD	$342,586	$184,701
NET INCOME (LOSS) PER SHARE — BASIC	$0.21	$(0.00)
NET INCOME (LOSS) PER SHARE — DILUTED	$0.20	$(0.00)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 5)	282,138,525	278,734,280
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 5)	285,026,183	278,734,280

(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)

	March 31, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$235,910	$212,624
Restricted cash	1,375	1,404
Accounts receivable	147,791	119,844
Inventory (Note 4)	18,320	33,468
Taxes receivable	14,326	39,922
Prepaids	4,332	4,074
Deferred tax assets (Note 7)	1,361	2,517
Total Current Assets	423,415	413,853
Oil and Gas Properties (using the full cost method of accounting)		
Proved	802,267	813,247
Unproved	418,647	383,414
Total Oil and Gas Properties	1,220,914	1,196,661
Other capital assets	8,946	8,765
Total Property, Plant and Equipment (Note 4)	1,229,860	1,205,426
Other Long-Term Assets		
Restricted cash	2,386	1,619
Deferred tax assets (Note 7)	2,807	1,401
Taxes receivable	2,564	1,374
Other long-term assets	7,448	6,621
Goodwill	102,581	102,581
Total Other Long-Term Assets	117,786	113,596
Total Assets	$1,771,061	$1,732,875
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts payable	$66,058	$102,263
Accrued liabilities	78,480	66,418
Taxes payable	31,387	22,339
Deferred tax liabilities (Note 7)	668	337
Asset retirement obligation (Note 6)	—	28
Total Current Liabilities	176,593	191,385
Long-Term Liabilities		
Deferred tax liabilities (Note 7)	211,515	225,195
Equity tax payable (Note 7)	3,437	3,562
Asset retirement obligation (Note 6)	18,930	18,264
Other long-term liabilities	7,382	3,038
Total Long-Term Liabilities	241,264	250,059
Contingencies (Note 8)		
Shareholders’ Equity		

Common Stock (Note 5) (269,518,147 and 268,482,445 shares of Common Stock and 13,122,988 and 13,421,488 exchangeable shares, par value $0.001 per share, issued and outstanding as at March 31, 2013 and December 31, 2012, respectively)	8,973	7,986
Additional paid in capital	1,001,645	998,772
Retained earnings	342,586	284,673
Total Shareholders' Equity	1,353,204	1,291,431
Total Liabilities and Shareholders' Equity	$1,771,061	$1,732,875

(See notes to the condensed consolidated financial statements)

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

	Three Months Ended March 31, 2013	2012
Operating Activities		
Net income (loss)	$57,913	$(313)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, accretion and impairment	58,412	60,367
Deferred tax recovery (Note 7)	(7,450)	(5,250)
Stock-based compensation (Note 5)	2,067	3,192
Unrealized foreign exchange (gain) loss	(6,744)	21,351
Settlement of asset retirement obligation (Note 6)	—	(404)
Other loss (Note 8)	4,400	—
Net change in assets and liabilities from operating activities		
Accounts receivable and other long-term assets	(29,387)	(72,865)
Inventory	11,643	(4,500)
Prepaids	(258)	(618)
Accounts payable and accrued and other liabilities	(14,731)	(34,035)
Taxes receivable and payable	33,926	19,595
Net cash provided by (used in) operating activities	109,791	(13,480)
Investing Activities		
Increase in restricted cash	(738)	(31,037)
Additions to property, plant and equipment	(87,378)	(77,983)
Net cash used in investing activities	(88,116)	(109,020)
Financing Activities		
Proceeds from issuance of shares of Common Stock	1,611	891
Net cash provided by financing activities	1,611	891
Net increase (decrease) in cash and cash equivalents	23,286	(121,609)
Cash and cash equivalents, beginning of period	212,624	351,685
Cash and cash equivalents, end of period	$235,910	$230,076
Cash	$230,767	$148,035
Term deposits	5,143	82,041
Cash and cash equivalents, end of period	$235,910	$230,076
Supplemental cash flow disclosures:		
Cash paid for income taxes	$13,103	$13,733
Non-cash investing activities:		
Non-cash net liabilities related to property, plant and equipment, end of period	$66,536	$53,090

(See notes to the condensed consolidated financial statements)

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

	Three Months Ended March 31, 2013	Year Ended December 31, 2012
Share Capital		
Balance, beginning of period	$7,986	$7,510
Issue of shares of Common Stock (Note 5)	987	476
Balance, end of period	8,973	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)	624	960
Stock-based compensation (Note 5)	2,249	13,116
Balance, end of period	1,001,645	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	57,913	99,659
Balance, end of period	342,586	284,673
Total Shareholders' Equity	$1,353,204	$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. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

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.

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 March 31, 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 March 31, 2013					
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	180,003	18,540	—	6,237	—	204,780
Interest income	161	243	14	9	164	591
Depletion, depreciation, accretion and impairment	45,956	7,950	62	4,171	273	58,412
Depletion, depreciation, accretion and impairment - per unit of production	26.32	26.68	—	65.34	—	27.71
Income (loss) before income taxes	101,668	(1,636)	(1,227)	(439)	(3,014)	95,352
Segment capital expenditures	30,407	4,805	29,247	14,539	11	79,009

	Three Months Ended March 31, 2012					
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	138,633	15,369	—	1,246	—	155,248
Interest income	204	47	15	294	143	703
Depletion, depreciation, accretion and impairment	32,286	5,925	115	21,808	233	60,367
Depletion, depreciation, accretion and impairment - per unit of production	25.80	22.80	—	1,741.44	—	39.62
Income (loss) before income taxes	60,120	(477)	(727)	(22,070)	(6,023)	30,823
Segment capital expenditures	20,349	14,105	16,655	36,256	226	87,591

	As at March 31, 2013					
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	All Other	Total
Property, plant and equipment	$827,899	$136,029	$125,125	$137,772	$3,035	$1,229,860
Goodwill	102,581	—	—	—	—	102,581
Other assets	229,313	43,556	15,593	5,262	144,896	438,620
Total Assets	$1,159,793	$179,585	$140,718	$143,034	$147,931	$1,771,061

	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 three months ended March 31, 2013, the Company had three significant customers in Colombia: Ecopetrol S.A. ("Ecopetrol") and two other customers, which accounted for 54%, 21% and 11%, respectively, of the Company's consolidated revenue and other income for the three months ended March 31, 2013. For the three months ended

March 31, 2012, sales to Ecopetrol accounted for 85% of the Company's consolidated revenues.

4. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

	As at March 31, 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	$1,605,483	$(803,216)	$802,267	$1,562,477	$(749,230)	$813,247
Unproved	418,647	—	418,647	383,414	—	383,414
	2,024,130	(803,216)	1,220,914	1,945,891	(749,230)	1,196,661
Furniture and fixtures and leasehold improvements	7,514	(5,239)	2,275	7,575	(5,093)	2,482
Computer equipment	11,709	(5,675)	6,034	10,971	(5,248)	5,723
Automobiles	1,469	(832)	637	1,376	(816)	560
Total Property, Plant and Equipment	$2,044,822	$(814,962)	$1,229,860	$1,965,813	$(760,387)	$1,205,426

Depletion and depreciation expense on property, plant and equipment for the three months ended March 31, 2013, was $54.6 million (three months ended March 31, 2012 - $42.6 million). A portion of depletion and depreciation expense was recorded as inventory in each period and adjusted for inventory changes.

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

The amounts of G&A and stock-based compensation capitalized in each of the Company's cost centers during the three months ended March 31, 2013 and 2012, respectively, were as follows:

	Three Months Ended March 31, 2013				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	$4,874	$1,265	$1,570	$1,145	$8,854
Capitalized stock-based compensation	$74	$60	$—	$48	$182

	Three Months Ended March 31, 2012				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
	$1,852	$1,080	$927	$1,068	$4,927

Capitalized G&A, including stock-based compensation					
Capitalized stock-based compensation	$114	$66	$—	$59	$239

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Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. As at March 31, 2013, the Company had $177.0 million (December 31, 2012 - $175.9 million) of unproved assets in Colombia, $41.6 million (December 31, 2012 - $42.3 million) of unproved assets in Argentina, $124.3 million (December 31, 2012 - $95.1 million) of unproved assets in Peru, and $75.7 million (December 31, 2012 - $70.1 million) of unproved assets in Brazil for a total of $418.6 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 53% of costs not subject to depletion at March 31, 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 March 31, 2013, oil and supplies inventories were $16.0 million and $2.3 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 March 31, 2013, outstanding share capital consists of 269,518,147 shares of Common Stock of the Company, 6,899,178 exchangeable shares of Gran Tierra Exchange Co., (the "Exchangeco exchangeable shares") that will be automatically exchangeable on November 14, 2013, except under certain specified circumstances, and 6,223,810 exchangeable shares of Goldstrike Exchange Co. (the "Goldstrike exchangeable shares"), automatically exchangeable on November 10, 2013. During the three months ended March 31, 2013, 737,202 shares of Common Stock were issued upon the exercise of stock options and 298,500 shares of common stock were issued upon the exchange of the Exchangeco exchangeable shares.

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

The Exchangeco exchangeable shares were issued upon acquisition of Solana 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. On October 5, 2012, the automatic redemption date on the Goldstrike exchangeable shares was extended by one year to November 10, 2013. As at March 31, 2013, 95.8% of the outstanding Goldstrike exchangeable shares were held by directors and management of the Company. Holders of exchangeable shares have substantially the same rights as holders of shares of Common Stock. Each exchangeable share is exchangeable into one share of Common Stock of the Company.

Stock Options

The Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants in accordance with the 2007 Equity Incentive Plan. The Company did not make its customary annual grant of options during the three months ended March 31, 2013, because the Company was assessing proposed changes to its long-term incentive plan.

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The following table provides information about stock option activity for the three months ended March 31, 2013:

	Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2012	15,399,662	5.11
Granted	75,000	6.00
Exercised	(737,202)	(2.18)
Forfeited	(117,211)	(6.31)
Expired	(29,766)	(6.89)
Balance, March 31, 2013	14,590,483	5.25

For the three months ended March 31, 2013, 737,202 shares of Common Stock were issued for cash proceeds of $1.6 million upon the exercise of 737,202 stock options (three months ended March 31, 2012 - $0.9 million).

The weighted average grant date fair value for options granted in the three months ended March 31, 2013, was $3.33 (three months ended March 31, 2012 - $3.37).

For the three months ended March 31, 2013, the stock-based compensation expense was $2.2 million (three months ended March 31, 2012- $3.4 million) of which $1.8 million (three months ended March 31, 2012 - $2.9 million) was recorded in G&A expenses, $0.2 million was recorded in operating expenses (three months ended March 31, 2012 – $0.3 million) and $0.2 million was capitalized as part of exploration and development costs (three months ended March 31, 2012 – $0.2 million).

At March 31, 2013, there was $6.0 million (December 31, 2012 - $8.2 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next two 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 March 31,	
	2013	2012
Weighted average number of common and exchangeable shares outstanding	282,138,525	278,734,280
Shares issuable pursuant to stock options	5,482,456	—
Shares assumed to be purchased from proceeds of stock options	(2,594,798)	—
Weighted average number of diluted common and exchangeable shares outstanding	285,026,183	278,734,280

For the three months ended March 31, 2013, 9,392,605 options (three months ended March 31, 2012 - 15,694,501 options and 6,098,224 warrants to purchase 3,049,112 shares of Common Stock) were excluded from the diluted income per share calculation as the options were anti-dilutive.

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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)	Three Months Ended March 31, 2013	Year Ended December 31, 2012
Balance, beginning of year	$18,292	$12,669
Settlements	—	(404)
Liability incurred	237	5,190
Liability assumed in a business combination	—	410
Foreign exchange	(9)	45
Accretion	410	998
Revisions in estimated liability	—	(616)
Balance, end of period	$18,930	$18,292
Asset retirement obligation - current	$—	$28
Asset retirement obligation - long-term	18,930	18,264
Balance, end of period	$18,930	$18,292

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 March 31, 2013, the fair value of assets that are legally restricted for purposes of settling asset retirement obligations was $2.0 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:

	Three Months Ended March 31,	
(Thousands of U.S. Dollars)	2013	2012
Income (loss) before income taxes		
United States	(2,091)	634
Foreign	97,443	30,189
	95,352	30,823
	35%	35%
Income tax expense expected	33,373	10,788
Foreign currency translation adjustments	(1,878)	8,718
Impact of foreign taxes	(224)	(631)
Stock-based compensation	686	1,003
Increase in valuation allowance	1,844	10,145
Branch and other foreign loss pick-up	(827)	(622)
Non-deductible third party royalty in Colombia	3,547	1,943
Other permanent differences	918	(208)
Total income tax expense	$37,439	$31,136
Current income tax expense		
United States	306	172
Foreign	44,583	36,214
	44,889	36,386
Deferred income tax recovery		
United States	—	—
Foreign	(7,450)	(5,250)
	(7,450)	(5,250)
Total income tax expense	$37,439	$31,136

	As at	
(Thousands of U.S. Dollars)	March 31, 2013	December 31, 2012
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	$54,136	$51,920
Tax basis in excess of book basis	23,139	22,519
Foreign tax credits and other accruals	30,063	30,926
Tax benefit of capital loss carryforwards	4,674	4,779
Deferred tax assets before valuation allowance	112,012	110,144
Valuation allowance	(107,844)	(106,226)
	$4,168	$3,918
Deferred tax assets - current	$1,361	$2,517
Deferred tax assets - long-term	2,807	1,401
	4,168	3,918
Deferred tax liabilities - current	(668)	(337)
Deferred tax liabilities - long-term	(211,515)	(225,195)
	$(212,183)	$(225,532)
Net Deferred Tax Liabilities	$(208,015)	$(221,614)

As at March 31, 2013, the Company had operating loss carryforwards of $223.4 million (December 31, 2012 - $213.1 million) and capital loss carryforwards of $35.0 million (December 31, 2012 – $35.9 million) before valuation allowance. Of these operating loss carryforwards and capital loss carryforwards, $224.8 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 2013 and 2017, while certain other jurisdictions allow operating losses to be carried forward indefinitely.

As at March 31, 2013, the total amount of Gran Tierra’s unrecognized tax benefit was approximately $21.8 million (December 31, 2012 - $21.8 million), a portion of which, if recognized, would affect the Company’s effective tax rate. There was no change in the Company's unrecognized tax benefit during the three months ended March 31, 2013, or 2012. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations. As at March 31, 2013, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the consolidated balance sheet was approximately $3.6 million (December 31, 2012 - $3.6 million). The Company had no other material interest or penalties included in the consolidated statement of operations for the three months ended March 31, 2013, and 2012, respectively.

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 March 31, 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 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 three months ended March 31, 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 three months ended March 31, 2013, based on market oil prices in Colombia, we 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 five million barrels. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a non-compliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five million barrels. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process and filed an arbitration claim. As at March 31, 2013, total cumulative production from the Moqueta field was 1.2 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH’s interpretation is successful is $20.0 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 March 31, 2013, the estimated compensation which would be payable if the ANH’s interpretation is successful is $15.7 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 March 31, 2013, the Company had provided promissory notes totaling $47.0 million (December 31, 2012 - $34.2 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

9. Financial Instruments, Fair Value Measurements and Credit Risk

At March 31, 2013, the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued liabilities and contingent consideration 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 March 31, 2013, and December 31, 2012. The fair value of the contingent liability was $4.4 million at March 31, 2013. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments. At March 31, 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 March 31, 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 March 31, 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 governments and financial institutions with strong investment grade ratings, or the equivalent in the Company’s operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in the Company’s operating areas.

Most of the Company’s accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company’s overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the three months ended March 31, 2013, the Company had three significant customers for its Colombian oil and three significant customers in Argentina.

For the three months ended March 31, 2013, 88% (three months ended March 31, 2012 - 89%) of our revenue and other income was generated in Colombia.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra’s current and deferred tax liabilities, monetary liabilities, which are mainly denominated in the local currency of the Colombian foreign operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $113,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for Gran Tierra's Argentina subsidiaries to make dividends or loan payments to the company. At March 31, 2013, $22.8 million, or 10%, of our cash and cash equivalents was deposited with banks in Argentina. We expect to use to these funds for the work program and operations in Argentina in 2013.

10. Credit Facilities

At March 31, 2013, a subsidiary of Gran Tierra had a credit facility with Wells Fargo Bank National Association. This reserve-based facility has a maximum borrowing base up to $100 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 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. The original credit facility became effective on July 30, 2010, for a three-year term. Under the terms of the facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. As at March 31, 2013, and December 31, 2012, the Company had not drawn down any amounts under this facility. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility and, if the Company is not in default, then it is required to obtain bank approval for any dividend payments exceeding $2 million in any fiscal year.

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 months ended March 31, 2013, $3.2 million (three months ended March 31, 2012 - $nil) was incurred and capitalized under this contract and at March 31, 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 in Colombia, Argentina, Peru and Brazil, and we are headquartered in Calgary, Alberta, Canada. For the three months ended March 31, 2013, 88% (three months ended March 31, 2012 - 89%) of our revenue and other income was generated in Colombia.

Highlights

	Three Months Ended March 31,		
	2013	2012	% Change
Production (BOEPD) (1)	23,424	16,742	40
Prices Realized - per BOE	$97.14	$101.90	(5)
Revenue and Other Income ($000s)	$205,371	$155,951	32
Net Income (Loss) ($000s)	$57,913	$(313)	—
Net Income (Loss) Per Share - Basic	$0.21	$(0.00)	—
Net Income (Loss) Per Share - Diluted	$0.20	$(0.00)	—
Funds Flow From Operations ($000s) (2)	$108,598	$78,943	38
Capital Expenditures ($000s)	$79,009	$87,591	(10)

	As at		
	March 31, 2013	December 31, 2012	% Change
Cash & Cash Equivalents ($000s)	$235,910	$212,624	11
Working Capital (including cash & cash equivalents) ($000s)	$246,822	$222,468	11

Property, Plant & Equipment ($000s)	$1,229,860	$1,205,426	2

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

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(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 or loss adjusted for depletion, depreciation, accretion and impairment (“DD&A”) expenses, deferred taxes, stock-based compensation, unrealized foreign exchange loss or gain, settlement of asset retirement obligation and other loss. A reconciliation from net income to funds flow from operations is as follows:

	Three Months Ended March 31,	
Funds Flow From Operations - Non-GAAP Measure ($000s)	2013	2012
Net income (loss)	$57,913	$(313)
Adjustments to reconcile net income (loss) to funds flow from operations		
DD&A expenses	58,412	60,367
Deferred taxes	(7,450)	(5,250)
Stock-based compensation	2,067	3,192
Unrealized foreign exchange (gain) loss	(6,744)	21,351
Settlement of asset retirement obligation	—	(404)
Other loss	4,400	—
Funds flow from operations	$108,598	$78,943

- For the three months ended March 31, 2013, oil and gas production, NAR and adjusted for inventory changes, increased by 40% to 23,424 BOEPD compared with the comparable period in 2012. Alternative transportation arrangements to minimize the impact of pipeline disruptions in Colombia, a decrease in oil inventory in Colombia, and production from new wells in Colombia and Argentina all had a positive impact on production in 2013. The net inventory reduction accounted for 0.1 MMbl or 1,554 BOEPD of the reported increase in production in the three months ended March 31, 2013. In 2013, production was 75% from the Chaza Block in Colombia and 8% and 5% from the Puesto Morales and Surubi Blocks in Argentina, respectively.

- For the three months ended March 31, 2013, revenue and other income increased by 32% to $205.4 million compared with $156.0 million in 2012. The positive contribution from higher production levels was partially offset by lower realized prices. The average price realized per BOE of $97.14, decreased by 5% from $101.90 in 2012.

- Net income was $57.9 million, or $0.21 per share basic and $0.20 per share diluted, for the three months ended March 31, 2013, compared with a loss of $0.3 million, or $0.00 per share basic and diluted, in 2012. In 2013, increased oil and natural gas sales, decreased DD&A and general and administrative ("G&A") expenses and a foreign exchange gain were partially offset by increased operating and income tax expenses and other losses.

- For the three months ended March 31, 2013, funds flow from operations increased by 38% from $78.9 million to $108.6 million primarily due to increased oil and natural gas sales, decreased G&A expenses and realized foreign exchange losses, partially offset by increased operating and income tax expenses and other losses.

- Cash and cash equivalents were $235.9 million at March 31, 2013, compared with $212.6 million at December 31, 2012. The increase in cash and cash equivalents during 2013 was primarily the result of funds flow from operations of $108.6 million, partially offset by capital expenditures of $87.4 million.

Working capital (including cash and cash equivalents) was $246.8 million at March 31, 2013, a $24.4 million increase from December 31, 2012. The increase was primarily a result of the following: a $23.3 million increase in cash and cash equivalents; a $27.9 million increase in accounts receivable primarily related to increased volumes sold and increased prices for sales to Ecopetrol S.A. ("Ecopetrol") in Colombia, partially offset by the impact of a reduction in the number of days of sales outstanding in Argentina; and a $24.1 million decrease in accounts payable and accrued liabilities mainly in relation to our capital program and the timing of payments for drilling in Colombia. These increases in cash and working capital were partially offset by the following: a $15.1 million decrease in inventory primarily due to the timing of recognition of oil sales to a customer in Colombia where the sale is recognized when the

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customer exports oil; a $25.6 million decrease in net taxes receivable due to the reimbursement of value added tax receivable and increased taxable income in Colombia; and a $9.0 million increase in taxes payable due to increased taxable income in Colombia.

- Property, plant and equipment at March 31, 2013, was $1.2 billion, an increase of $24.4 million from December 31, 2012, as a result of $79.0 million of capital expenditures (excluding changes in non-cash working capital), partially offset by $54.6 million of depletion, depreciation and impairment expenses.

- Our capital expenditures for the three months ended March 31, 2013, were $79.0 million compared with $87.6 million for the three months ended March 31, 2012. In 2013, capital expenditures included drilling of $58.1 million, geological and geophysical (“G&G”) expenditures of $8.0 million, facilities of $7.0 million and other expenditures of $5.9 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 demand growth.

We believe that our current operations and 2013 capital expenditure program can be funded from cash flow from existing operations, cash on hand and potential periodic draws from our revolving credit facility. Should our operating cash flow decline 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, issuance of debt, disposition of assets, or issuance of equity. Continuing social uncertainty in the Middle East and North Africa, economic uncertainty in the United States, Europe and China 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.

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 March 31, 2013	2012	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$204,780	$155,248	32
Interest income	591	703	(16)
	205,371	155,951	32
Operating expenses	41,015	24,487	67
DD&A expenses	58,412	60,367	(3)
G&A expenses	11,421	15,899	(28)
Foreign exchange (gain) loss	(5,229)	24,375	(121)
Other loss	4,400	—	—
	110,019	125,128	(12)
Income before income taxes	95,352	30,823	209
Income tax expense	(37,439)	(31,136)	20
Net income (loss)	$57,913	$(313)	—
Production			
Oil and NGL's, bbl	2,052,737	1,461,404	40
Natural gas, Mcf	332,613	372,947	(11)
Total production, BOE (1)	2,108,173	1,523,562	38
Average Prices			
Oil and NGL's per bbl	$99.17	$105.36	(6)
Natural gas per Mcf	$3.61	$3.42	6
Consolidated Results of Operations per BOE			
Oil and natural gas sales	$97.14	$101.90	(5)
Interest income	0.28	0.46	(39)
	97.42	102.36	(5)
Operating expenses	19.46	16.07	21
DD&A expenses	27.71	39.62	(30)
G&A expenses	5.42	10.44	(48)
Foreign exchange (gain) loss	(2.48)	16.00	(116)
Other loss	2.09	—	—
	52.20	82.13	(36)
Income before income taxes	45.22	20.23	124
Income tax expense	(17.76)	(20.44)	(13)
Net income (loss)	$27.46	$(0.21)	—

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

Net income for the three months ended March 31, 2013, was $57.9 million, compared to a loss of $0.3 million in the comparable period in 2012. On a per share basis, net income increased to $0.21 per share basic and $0.20 per share diluted from $0.00 per share basic and diluted in 2012. For the three months ended March 31, 2013, increased oil and natural gas sales, decreased DD&A and G&A expenses and a foreign exchange gain, were partially offset by increased operating and income tax expenses and other loss.

Oil and NGL production for the three months ended March 31, 2013, increased to 2.1 MMbbl compared with 1.5 MMbbl in 2012. The increase was due to the reduced impact of pipeline disruptions in Colombia, a decrease in oil inventory in the

Ecopetrol-operated Trans-Andean oil pipeline (the "OTA pipeline") and associated Ecopetrol owned facilities in the Putumayo Basin, reduced oil inventory related to sales to a customer in Colombia with a protracted sales cycle whereby the transfer of ownership occurs upon export, and production from new wells in Colombia and Argentina. The net inventory reduction accounted for 0.1 MMbl or 1,554 BOEPD of the reported increase in production. Production during the three months ended March 31, 2013, reflected approximately 44 days of oil pipeline delivery restrictions in Colombia.

Average realized oil prices decreased by 6% to $99.17 per bbl from $105.36 per bbl for the three months ended March 31, 2013. Average Brent oil prices for the three months ended March 31, 2013, were $112.51 per bbl compared with $118.56 per bbl in 2012. WTI oil prices for the three months ended March 31, 2013, averaged $94.40 per bbl compared with $102.89 per bbl in 2012.

Revenue and other income for the three months ended March 31, 2013, increased to $205.4 million from $156.0 million in 2012 as a result of increased production, partially offset by decreased realized prices.

Operating expenses for the three months ended March 31, 2013, were $41.0 million, or $19.46 per BOE, compared with $24.5 million, or $16.07 per BOE, in 2012. The increase in operating expenses was primarily due to an increase of $13.5 million in Colombia related to increased production volumes, OTA pipeline oil transportation costs recorded as operating costs versus as a reduction of revenue effective February 1, 2012, pursuant to a change in the sales point on that date, and increased G&A allocations to operating costs.

DD&A expenses for the three months ended March 31, 2013, decreased to $58.4 million from $60.4 million in 2012. The impact of increased production was more than offset by the absence of impairment charges. DD&A expenses for the three months ended March 31, 2012, included a $20.2 million ceiling test impairment in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. On a per BOE basis, the depletion rate decreased by 30% to $27.71 from $39.62. The decrease was mainly due to the Brazil impairment charge of $13.26 per BOE in 2012. Increased costs in the depletable base were partially offset by increased reserves.

G&A expenses for the three months ended March 31, 2013, of $11.4 million decreased by 28% from $15.9 million in 2012. Increased employee related costs reflecting expanded operations were more than offset by increased recoveries and higher G&A allocations to operating expenses and capital projects in all business units. G&A expenses per BOE in the three months ended March 31, 2013, of $5.42 were 48% lower compared with $10.44 in 2012 due to increased production and increased recoveries and higher G&A allocations in Colombia.

For the three months ended March 31, 2013, the foreign exchange gain was $5.2 million, comprising a $6.7 million unrealized non-cash foreign exchange gain, offset by realized foreign exchange losses of $1.5 million. The foreign exchange gain was a result of a net monetary liability position in Colombia combined with the weakening of the Colombian Peso; whereas, the foreign exchange losses resulted from a net monetary asset position in Argentina and the weakening of the Argentina Peso. For the three months ended March 31, 2012, there was a foreign exchange loss of $24.4 million, of which $21.4 million was an unrealized non-cash foreign exchange loss, as a result of a net monetary liability position in Colombia combined with the strengthening of the Colombian Peso.

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

Income tax expense was $37.4 million for the three months ended March 31, 2013, compared with $31.1 million in the comparable period in 2012. The increase was primarily due to higher income before tax. The effective tax rate was 39% in the three months ended March 31, 2013, compared with 101% 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 a decrease in the valuation allowance, partially offset by an increase in non-deductible royalty payments.

For 2013, the differential between the effective tax rate of 39% and the 35% U.S. statutory rate was primarily attributable to
non-deductible third party royalty in Colombia, the change in valuation allowance, non-deductible foreign currency translation adjustments, and the foreign tax rate differential. The variance from the 35% U.S. statutory rate for 2012 was primarily attributable to the valuation allowance and non-deductible foreign currency translation adjustments.

2013 Work Program and Capital Expenditure Program

Our 2013 capital program has been revised to $424 million from $363 million. This includes: $223 million for Colombia; $77 million for Brazil; $20 million for Argentina; $101 million for Peru; and $3 million associated with corporate activities. The majority of the increase is associated with capital spending in Peru and relates to the Bretaña Norte 95-2-1XD sidetrack well and additional 2-D seismic. The capital spending program allocates $218 million for drilling, $73 million for facilities, pipelines and other; $130 million for G&G expenditures; and $3 million for corporate activities. Of the $218 million allocated to drilling, approximately $100 million is for exploration and the balance is for appraisal and development drilling.

Our 2013 work program is intended to create both growth and value by developing existing assets to increase reserves and
production levels, the construction of pipelines and facilities in the areas with proved reserves, and maturing our exploration prospects through seismic acquisition and drilling. We are financing our capital program through cash flows from operations, cash on hand and potential periodic draws from our revolving credit facility, while retaining financial flexibility to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, 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 March 31,		
	2013	2012	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$180,003	$138,633	30
Interest income	161	204	(21)
	180,164	138,837	30
Operating expenses	29,952	16,474	82
DD&A expenses	45,956	32,286	42
G&A expenses	4,636	6,599	(30)
Foreign exchange (gain) loss	(6,448)	23,358	(128)
Other loss	4,400	—	—
	78,496	78,717	—
Income before income taxes	$101,668	$60,120	69
Production			
Oil and NGL's, bbl	1,746,326	1,249,581	40
Natural gas, Mcf	—	9,474	(100)
Total production, BOE (1)	1,746,326	1,251,160	40
Average Prices			
Oil and NGL's per bbl	$103.08	$110.92	(7)
Natural gas per Mcf	$—	$3.39	(100)
Segmented Results of Operations per BOE			
Oil and natural gas sales	$103.08	$110.80	(7)
Interest income	0.09	0.16	(44)
	103.17	110.96	(7)
Operating expenses	17.15	13.17	30
DD&A expenses	26.32	25.80	2
G&A expenses	2.65	5.27	(50)
Foreign exchange (gain) loss	(3.69)	18.67	(120)
Other loss	2.52	—	—
	44.95	62.91	(29)
Income before income taxes	$58.22	$48.05	21

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

For the three months ended March 31, 2013, income before income taxes was $101.7 million compared with $60.1 million in 2012. The increase was due to higher oil and natural gas sales as a result of increased Production, decreased

G&A expenses and a foreign exchange gain, partially offset by increased operating and DD&A expenses and other loss.

Oil and NGL Production for the three months ended March 31, 2013, increased to 1.7 MMbbl compared with 1.2 MMbbl for 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 MMbl or 1,554 BOEPD of the reported increase in production. Production during the three months ended March 31, 2013, reflected approximately 44 days of oil delivery restrictions in Colombia compared with 26 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.

On February 1, 2012, the sales point for the majority of our oil sales in the Putumayo Basin changed. Ecopetrol now takes title at the Port of Tumaco on the Pacific coast of Colombia rather than at the entry into the OTA pipeline. As a result, our reported oil inventory increased during the first quarter of 2012, representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. The impact of the inventory increase on production in the first quarter of 2012 was a negative effect on production of 1,040 BOPD.

Revenue and other income increased by 30% to $180.2 million for the three months ended March 31, 2013, compared with $138.8 million in 2012.

For the three months ended March 31, 2013, the average realized price per bbl for oil decreased by 7% to $103.08 compared with $110.92 in 2012. Average Brent oil prices for the three months ended March 31, 2013, were $112.51 per bbl compared with $118.56 per bbl in 2012.

During the three months ended March 31, 2013, 28% of our oil and gas sales were to a customer to whom oil is delivered at the Costayaco battery and the sales point is where the oil is loaded into a truck at our loading facility. This oil is then trucked from the Costayaco field to the Atlántico Oil Terminal in Barranquilla, a distance of approximately 1,500 kilometers. Oil prices for sales to this customer are based on average WTI prices plus a Vasconia differential and premium, adjusted for trucking costs. The effect on the Colombian realized price was a reduction of approximately $5.10 per BOE as compared to delivering all of our Colombian oil through the OTA pipeline.

Until February 1, 2012, OTA transportation costs were factored into the price we received for oil sales in the Putumayo Basin to Ecopetrol, but, due to the change in sales point noted above, these costs are now invoiced separately and included in operating costs. This change resulted in a related increase in the average realized price per bbl starting February 1, 2012.

Operating expenses increased by 82% to $30.0 million for the three months ended March 31, 2013, from $16.5 million in 2012. On a per BOE basis, operating expenses increased by 30% to $17.15 for the three months ended March 31, 2013, from $13.17 in 2012. Operating expenses per BOE increased in 2013 primarily due to OTA pipeline oil transportation costs now recorded as operating costs, increased G&A allocations to operating costs and new wells with higher operating costs. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the three months ended March 31, 2013 was neutral, with the increased trucking costs to an alternative pipeline offset by the absence of OTA pipeline charges relating to both these volumes and the volumes sold at the Costayaco battery. The trucking costs associated with the volumes sold at the Costayaco battery were a reduction of the realized price rather than recorded as transportation expenses and the effect on the realized price is as quantified above. Workover costs decreased by $0.42 per BOE compared with the comparable period in 2012. In 2013 and 2012, we performed workovers in the Costayaco and Juanambu fields and, in 2013, the Moqueta field.

DD&A expenses increased by 42% to $46.0 million for the three months ended March 31, 2013, from $32.3 million in 2012. On a per BOE basis, DD&A expenses increased by 2% to $26.32 for the three months ended March 31, 2013. The increase was due to increased costs in the depletable base being partially offset by increased reserves.

For the three months ended March 31, 2013, G&A expenses decreased by 30% to $4.6 million ($2.65 per BOE) from $6.6 million ($5.27 per BOE) in 2012 due to increased recoveries and G&A allocations to operating costs and capital projects, partially offset by increased salaries expense due to an increased headcount from expanded operations.

For the three months ended March 31, 2013, the foreign exchange gain was $6.4 million, which included a $6.7 million unrealized non-cash foreign exchange gain. In the three months ended March 31, 2012, we incurred a foreign exchange loss of $23.4 million, of which $21.4 million was an unrealized non-cash foreign exchange loss. The Colombian Peso weakened by 3% and strengthened by 8% against the U.S. dollar in the three months ended March 31, 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.

Other loss of $4.4 million in the three months ended March 31, 2013, relates to a contingent loss accrued in connection with a legal dispute where 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 March 31, 2013, were $30.4 million. The following table provides a breakdown of capital expenditures in the three months ended March 31, 2013 and 2012:

	Three Months Ended March 31,	
(Millions of U.S. Dollars)	2013	2012
Drilling and completions	$14.9	$10.5
G&G	5.3	7.1
Facilities and equipment	6.2	1.8
Other	4.0	0.9
	$30.4	$20.3

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

- On the Chaza Block (100% working interest ("WI"), operated), we completed the Moqueta-8 development well as a producing well and drilled the Moqueta-9D development well in the Moqueta field. Testing of the Moqueta-9D development well is ongoing. On the Costayaco field, we continued completion work at the Costayaco-17 water injector well and commenced drilling the Costayaco-18D development well.
- We commenced civil construction for one gross exploration well on the Guayuyaco Block (70% WI, operated).
- We acquired 3-D seismic on the Garibay Block (50% WI, non-operated) and started acquiring 2-D seismic on the Magdalena Block (100% WI, operated).
- We also continued facilities work at the Costayaco and Moqueta fields on the Chaza Block, the Llanos-22 Block (45% WI, non-operated) and the Guayuyaco Block.

Outlook - Colombia

The 2013 capital program in Colombia is $223 million with $109 million allocated to drilling, $48 million to facilities and pipelines and $66 million for G&G expenditures.

Our planned work program for the remainder of 2013 in Colombia includes drilling one oil exploration well on each of the Chaza and Putumayo-1 Blocks (100 % WI, operated) and two gross exploration wells on the Guayuyaco Block. We plan to finish the completion of the Costayaco-17 water injector well and complete drilling the Costayaco-18D development wells on the Chaza Block and drill two additional gross development wells on the Moqueta field of the Chaza Block, a development well on the Llanos-22 Block 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-7 (100% WI, operated), Putumayo-10 (100% WI, operated), Magdalena, Piedemonte Norte (70% WI, operated) 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 March 31,		
	2013	2012	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$18,540	$15,369	21
Interest income	243	47	417
	18,783	15,416	22
Operating expenses	8,971	7,346	22
DD&A expenses	7,950	5,925	34
G&A expenses	2,374	2,251	5
Foreign exchange loss	1,124	371	203
	20,419	15,893	28
Loss before income taxes	$(1,636)	$(477)	243
Production			
Oil and NGL's, bbl	242,577	199,300	22
Natural gas, Mcf	332,613	363,473	(8)
Total production, BOE (1)	298,013	259,879	15
Average Prices			
Oil and NGL's per bbl	$71.31	$70.87	1
Natural gas per Mcf	$3.74	$3.42	9
Segmented Results of Operations per BOE			
Oil and natural gas sales	$62.21	$59.14	5
Interest income	0.82	0.18	356
	63.03	59.32	6
Operating expenses	30.10	28.27	6
DD&A expenses	26.68	22.80	17
G&A expenses	7.97	8.66	(8)
Foreign exchange loss	3.77	1.43	164
	68.52	61.16	12
Loss before income taxes	$(5.49)	$(1.84)	198

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

For the three months ended March 31, 2013, loss before income taxes in Argentina was $1.6 million compared with $0.5 million in 2012. In 2013, increased oil and natural gas sales were more than offset by increased operating, DD&A and G&A expenses and foreign exchange losses.

Total Production of oil and gas from the Argentina segment increased by 15% to 0.3 MMBOE for the three months ended March 31, 2013, compared with the comparable period in 2012.

Oil and NGL production increased 22% to 0.2 MMbbl for the three months ended March 31, 2013, compared with the comparable period in 2012. The increase was primarily due to production from the Proa-2 well, in the Surubi Block, which began production in April 2012. This was partially offset by reduced production from the Puesto Morales Block due to well downtime for workovers and delays in the completion of the waterflood implementation.

Revenue and other income increased by 22% to $18.8 million for the three months ended March 31, 2013, compared with $15.4 million in 2012, due to increased oil and NGL production volumes and increased prices.

Average oil prices increased by 1% in the three months ended March 31, 2013, compared with the comparable period in 2012. Due to the Argentina regulatory regime, the average oil price we received for production from our blocks during the three months ended March 31, 2013, was $71.31 per bbl. Currently, most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis.

Operating expenses increased by 22% to $9.0 million for the three months ended March 31, 2013, compared with $7.3 million in 2012. The increase was primarily due to higher production volumes. On a per BOE basis, operating expenses increased by 6% to $30.10 for the three months ended March 31, 2013, from $28.27 in 2012. The increase in operating costs on a per BOE basis was due to lower production in Puesto Morales, partially offset by the effect of production from the Surubi Block, which has lower operating costs per BOE due to the high volumes produced.

DD&A expenses increased by 34% to $8.0 million for the three months ended March 31, 2013, compared with $5.9 million in 2012. On a per BOE basis, DD&A expenses were $26.68 for the three months ended March 31, 2013, 17% higher than DD&A expenses in 2012 of $22.80. The increase was due to increased costs in the depletable base, partially offset by increased reserves.

G&A expenses were $2.4 million ($7.97 per BOE) in the three months ended March 31, 2013, compared with $2.3 million ($8.66 per BOE) in the comparable period in 2012. For the three months ended March 31, 2013, G&A expenses increased due to higher salaries expense as a result of local inflation, partially offset by increased recoveries.

For the three months ended March 31, 2013, the foreign exchange loss was $1.1 million, compared with $0.4 million in the comparable period in 2012. The loss primarily related to realized foreign exchange losses on monetary assets in Argentina during the period. The Argentina Peso weakened by 4% and 2% against the U.S. dollar in the three months ended March 31, 2013, and 2012, respectively. The net monetary asset balance exposed to foreign exchange losses was higher in 2013 as compared to 2012 as a result of increased production and sales and lower capital expenditures.

Capital Program - Argentina

Capital expenditures in our Argentina segment during the three months ended March 31, 2013, were $4.8 million. Capital expenditures in 2013 included drilling of $2.7 million, G&G expenditures of $1.1 million, facilities of $0.5 million and other expenditures of $0.5 million.

The significant elements of our first quarter 2013 capital program in Argentina were:

- We drilled and completed one development well, PMN-1130-SB, and commenced drilling an additional development well, PMN-1131-SB, on the Puesto Morales Block (100% WI, operated). Both wells were on production subsequent to quarter end.

- We undertook facilities work at the Surubi Block (85% WI, operated).

Outlook – Argentina

The 2013 capital program in Argentina is $20 million with $10 million allocated to drilling, $4 million to facilities and pipelines, and $6 million to G&G expenditures.

With the previous announcement of the successful flow test for the PMN-1117 horizontal well, we plan to replace the two development wells originally planned for the second half of 2013 with a horizontal well into the Loma Montosa formation in the third quarter of 2013, to further evaluate this new play.

Our planned work program for the remainder of 2013 in Argentina includes drilling one development well on the Puesto Morales Block and workovers on existing wells. We also plan to perform facilities work on the El Chivil Block.

Segmented Results – Peru

	Three Months Ended March 31,		
	2013	2012	% Change
(Thousands of U.S. Dollars)			
Interest income	$14	$15	(7)
Operating expenses	—	$81	(100)
DD&A expenses	62	115	(46)
G&A expenses	1,006	616	63
Foreign exchange loss (gain)	173	(70)	(347)
	1,241	742	67
Loss before income taxes	$(1,227)	$(727)	69

G&A expenses were $1.0 million in the three months ended March 31, 2013, compared with $0.6 million in the comparable period in 2012. The increase was primarily due to lower recoveries due to our acquisition of the remaining 40% working interest in Block 95 and higher salaries expense resulting from expanded operations, partially offset by increased capitalized costs.

Capital Program – Peru

Capital expenditures in our Peruvian segment for the three months ended March 31, 2013, were $29.2 million. Capital expenditures in 2013 included drilling of $27.5 million, G&G expenditures of $1.2 million and other expenditures of $0.5 million.

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

- On Block 95 (100% WI, operated), we completed drilling and successfully tested the Bretaña Norte 95-2-1XD exploration well. We initiated drilling of a horizontal side-track extension of the exploration well. We also continued work to obtain the necessary environmental and social permits for future drilling activities and seismic programs.

- On Block 133 (100% WI, operated), we commenced an aeromagnetic and aerogravity survey.

- 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 $101 million with $48 million allocated to drilling, $2 million for facilities and $51 million for G&G expenditures.

Our planned work program for the remainder of 2013 includes the commencement of long-term testing on the Bretaña Norte 95-2-1XD exploration well, infill seismic on Bretaña field and other identified leads on Block 95 and preliminary field development planning for the Bretaña Norte field development.

Additionally, we plan to complete the aeromagnetic and aerogravity survey on Block 133, commence 2-D seismic programs on Block 95 and Block 107 and commence Environmental Impact Assessments on Block 133, Block 123 and Block 129.

Segmented Results - Brazil

	Three Months Ended March 31,		
	2013	2012	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$6,237	$1,246	401
Interest income	9	294	(97)
	6,246	1,540	306
Operating expenses	2,091	585	257
DD&A expenses	4,171	21,808	(81)
G&A expenses	426	681	(37)
Foreign exchange (gain) loss	(3)	536	(101)
	6,685	23,610	(72)
Loss before income taxes	$(439)	$(22,070)	(98)
Production (1)			
Oil and NGL's, bbl	63,834	12,523	410
Average Prices			
Oil and NGL's per bbl	$97.71	$99.50	(2)
Segmented Results of Operations per bbl			
Oil and natural gas sales	$97.71	$99.50	(2)
Interest income	0.14	23.48	(99)
	97.85	122.98	(20)
Operating expenses	32.76	46.71	(30)
DD&A expenses	65.34	1,741.44	(96)
G&A expenses	6.67	54.38	(88)
Foreign exchange (gain) loss	(0.05)	42.80	(100)
	104.72	1,885.33	(94)
Loss before income taxes	$(6.87)	$(1,762.35)	(100)

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

For the three months ended March 31, 2013, loss before income taxes was $0.4 million compared with $22.1 million in the comparable period in 2012. Loss before income 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 March 31, 2013, we had three producing wells in this field compared with one producing well in the comparable period in 2012. 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.

Revenue and other income increased to $6.2 million for the three months ended March 31, 2013, compared with $1.5 million in 2012, due to increased oil production volumes, partially offset by decreased prices. The price we receive in Brazil is at a discount to Brent due to refining and quality discounts.

Operating expenses increased to $2.1 million for the three months ended March 31, 2013, from $0.6 million in the comparable period in 2012 due to higher production volumes. On a per bbl basis, operating expenses decreased by 30% to $32.76 for the three months ended March 31, 2013, from $46.71 in the comparable period in 2012. Operating expenses per bbl decreased due to increased production.

DD&A expenses were $4.2 million in the three months ended March 31, 2013, compared with $21.8 million in the comparable period in 2012. DD&A in 2012, included a ceiling test impairment loss of $20.2 million. The impairment loss related to seismic and drilling costs on Block BM-CAL-10.

Capital Program – Brazil

Capital expenditures in our Brazilian segment during the three months ended March 31, 2013, were $14.5 million. Capital expenditures in 2013 included drilling of $13.0 million, facilities of $0.3 million, G&G expenditures of $0.4 million and $0.8 million of other expenditures.

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

- We commenced drilling a horizontal sidetrack oil exploration well, 1-GTE-07-BA, in the Tiê field on Block REC-T-155 (100% WI, operated) and drilled one horizontal sidetrack oil exploration well, 1-GTE-06HP-BA, on Block REC-T-129 (100% WI, operated).
- On Block REC-T-142 (100% WI, operated), our horizontal multi-stage fracture stimulation exploration drilling program is ongoing.

Outlook – Brazil

The 2013 capital program in Brazil is $77 million with $51 million allocated to drilling, $19 million to facilities and pipelines and $7 million for G&G and other expenditures.

Our planned work program for the remainder of 2013 in Brazil includes the completion of the two horizontal sidetrack oil exploration wells on Block REC-T-155 and Block REC-T-129, drilling and completion of an additional oil exploration well on Block REC-T-155, additional completion work on the 3-GTE-03-BA and 3-GTE-04-BA producing wells in the Tiê field and fracture stimulation operations on Block REC-T-142. We also plan to perform facilities and pipeline work on Block REC-T-155 and plan to acquire 3-D seismic on Block BM-CAL-7 (10% WI, non-operated) in the offshore Camamu Basin.

Results - Corporate Activities

	Three Months Ended March 31,		
	2013	2012	% Change
(Thousands of U.S. Dollars)			
Interest income	$164	$143	15
DD&A expenses	273	233	17
G&A expenses	2,980	5,753	(48)
Foreign exchange (gain) loss	(75)	180	(142)

	3,178	6,166	(48)
Loss before income taxes	$(3,014)	$(6,023)	(50)

G&A expenses in the three months ended March 31, 2013, were $3.0 million compared with $5.8 million in the comparable period in 2012. The reduction was primarily due to an increase in costs recovered from business units and lower consulting

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costs. Additionally, stock-based compensation was lower as we made only minimal stock option grants in the three months ended March 31, 2013 while we assessed proposed changes to the long-term incentive plan.

Liquidity and Capital Resources

At March 31, 2013, we had cash and cash equivalents of $235.9 million compared with $212.6 million at December 31, 2012.

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

At March 31, 2013, 93% of our cash and cash equivalents was held by our foreign subsidiaries. This balance is not available to fund domestic operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested 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 Central Bank may require prior authorization and may or may not grant such authorization for our Argentine subsidiaries to make dividends or loan payments to us. At March 31, 2013, $22.8 million, or 10%, of our cash and cash equivalents was deposited with banks in Argentina. We expect to use these funds for the 2013 Argentina work program and operations.

At March 31, 2013, one of our subsidiaries had a credit facility with Wells Fargo Bank National Association. This reserve-based facility has a maximum borrowing base up to $100 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 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. The original credit facility became effective on July 30, 2010, for a three-year term. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. As at March 31, 2013, and December 31, 2012, we had not drawn down any amounts under this facility. 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, then we are required to obtain bank approval for any dividend payments exceeding $2 million in any fiscal year.

Cash Flows

During the three months ended March 31, 2013, our cash and cash equivalents increased by $23.3 million as a result of cash provided by operating activities of $109.8 million and cash provided by financing activities of $1.6 million, partially offset by
cash used in investing activities of $88.1 million.

Cash provided by operating activities in the three months ended March 31, 2013, was primarily affected by increased oil and natural gas sales, decreased G&A expenses and lower realized foreign exchange losses. These increases were partially offset by increased operating and income tax expenses and a $1.2 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets increased by $29.4 million primarily due to increased volumes sold and prices for sales to Ecopetrol in Colombia, partially offset by the impact of a reduction in the number of days of sales outstanding in Argentina; inventory decreased by $11.6 million primarily due to the timing of recognition of oil sales to a customer in Colombia where the sale is recognized when the customer exports oil; accounts payable and accrued liabilities decreased by $14.7 million due to the timing of payments for drilling activity and reduced capital activity; and net taxes receivable decreased by $33.9 million resulting in net taxes payable due to the reimbursement of value added tax receivable and increased taxable income in Colombia.

Cash used in operating activities in the three months ended March 31, 2012, was negatively affected by a $92.4 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $72.9 million due to increased sales and the timing of collection of receivables; inventory increased by $4.5 million due to the new commercialization and transportation agreements in Colombia; accounts payable and accrued liabilities decreased by $34.0 million. These amounts were partially offset by an increase in net taxes payable of $19.6 million due to increased taxable income in Colombia. The decrease in accounts payable and accrued liabilities was due to a $19.0 million reduction in royalties payable and a $13.7 million reduction in VAT payable, partially offset by a $12.0 million increase in capital expenditure related liabilities.

Cash outflows from investing activities in the three months ended March 31, 2013, included capital expenditures of $87.4 million (including changes in non-cash working capital related to investing activities) and an increase in restricted cash of $0.7 million. Cash outflows from investing activities in the three months ended March 31, 2012, included capital expenditures of $78.0 million (including changes in non-cash working capital related to investing activities) and an increase in restricted cash of $31.0 million.

Cash provided by financing activities in the three months ended March 31, 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 March 31, 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 three months ended March 31, 2013, $3.2 million was incurred and capitalized under this contract and at March 31, 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 large degree by the nature of expenditures and revenues in the countries where we operate. We have not engaged in any formal hedging activity with regard to foreign currency risk. Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil.

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

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $113,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar. For the three months ended March 31, 2013, our realized foreign exchange loss was $1.5 million (three months ended March 31, 2012 - $3.0 million). The loss primarily related to realized foreign exchange losses on the net monetary assets in Argentina during the period. The Argentina Peso weakened by 4% and 2% against the U.S. dollar in the three months ended March 31, 2013, and 2012, respectively.

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

Item 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 March 31, 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 March 31, 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 March 31, 2013, total cumulative production from the Moqueta field was 1.2 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $20.0 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 March 31, 2013, the estimated compensation which would be payable if the

ANH's interpretation is successful is $15.7 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 March 31, 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, the 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, Middle Magdalena and Lower Magdalena Basins. The Putumayo and Catatumbo regions have been the breeding place of guerrilla activity. Beginning in 1989, our predecessor company's facilities in one field were attacked by guerrillas and operations were briefly disrupted. In October 2010, two of our sites in the Putumayo/Cauca were attacked by FARC guerrillas causing some disruption to operations. Pipelines have also been primary targets because such pipelines cannot be adequately secured due to the sheer 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. In March and April of 2008, June, July, August and October of 2009, June, August, and September of 2010, February 2011, February to August of 2012 and October 2012 to May 2013, sections of the OTA pipeline were sabotaged by guerrillas, which temporarily reduced our deliveries to Ecopetrol during the affected periods. 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. We have employed mitigation strategies as discussed in the risk "We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses" later in this section. Such disruptions may continue indefinitely and could harm our business.

On January 30, 2013, four contract workers employed by companies providing services to Gran Tierra in the Putumayo Basin were abducted, possibly by guerillas. One individual was released within an hour, the other three contract workers were returned unharmed the next day (January 31, 2013). No employees of Gran Tierra were involved in the incident. On March 8, 2013, three armed people entered a remote facility and started a fire resulting in damage to our facilities in the amount of approximately $1.1 million. Production of about 330 BOPD was shut in for 39 days. No long-term environmental damage or injury to personnel occurred. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

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

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

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

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

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

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, June, July and August of 2009, June, August, and September 2010, February 2011, February to August of 2012 and October 2012 to May 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 in January 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. 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 for short periods of time in Argentina. South America has a history of political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including the imposition of additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Argentina, Colombia, Peru or Brazil or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

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

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

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

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

Our capital program for 2013 calls for approximately $424 million to fund our exploration and development, which we intend to fund through existing cash, cash flows from operations and potential periodic draws from our revolving credit facility. Funding this program relies in part on oil prices remaining high and other factors to generate sufficient cash flow. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our business plan which would cause us to decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

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

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

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

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

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

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

Disputes or Uncertainties May Arise in Relation to our Royalty Obligations

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

In accordance with our Hydrocarbon Exploration and Exploitation Agreement with ANH for the Chaza Block in Colombia our oil production from each Exploitation Area on the Block is subject to the payment of additional compensation to the ANH over and above the basic sliding scale royalty that applies when cumulative gross production from an Exploitation Area exceeds five

MMbbl. Production from the Costayaco Exploitation Area on the Chaza Block became subject to this additional compensation in the fourth quarter of 2009 after cumulative production from the Costayaco field exceeded five MMbbl.

The ANH has requested that the additional compensation be paid with respect to production from the recently drilled wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, we view the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have sent notice to the ANH to initiate the dispute resolution process prescribed by the Chaza Contract 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 March 31, 2013, total cumulative production from the Moqueta field was 1.2 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $20.0 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 March 31, 2013, the estimated compensation which would be payable if the ANH's interpretation is successful is $15.7 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 Brazil, a new regulatory regime was introduced; however, the royalty distribution between producing states has not been approved.

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

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

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

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

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

Recently, the government of Argentina has been active in the oil and gas business. On April 16, 2012, the government announced their intention to acquire a 51% interest in YPF S.A. ("YPF") from Repsol S.A. (Repsol S.A. holds 56.7% of YPF), and retain 51% control for the Federal Government and distribute 49% of the shares to Argentina provinces. During 2012, the

Argentina government took control of YPF's operations and signed deals with Chevron Corporation and others for developing shale resources. Repsol S.A. has filed international complaints and US lawsuits regarding the takeover and subsequent deals. Prior to this announcement, various provincial governments announced contract cancellations effecting YPF, Petrobras Argentina S.A., and Azabache Energy Inc., among others. The reason cited for the contract cancellations was lack of activity in the areas in question. We have experienced recent success in Argentina and have active programs in all areas, which we believe helps mitigate our risk. However, despite the fact that our operating entity in Argentina is a locally incorporated company the employees of which are all Argentine, we are viewed as a foreign company and could therefore face increased risk.

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

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

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

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

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

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

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

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. Our production in Argentina is primarily invoiced in U.S. dollars, but payment is made in Argentina pesos, at the then current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Since we began operating in Argentina (September 1, 2005), the rate of exchange between the Argentina peso and U.S. dollar has varied between 3.05 pesos to one U.S. dollar to 5.16 pesos to the U.S. dollar, a fluctuation of approximately 69%. 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

3% in the Colombian Peso against the U.S. dollar in the three months ended March 31, 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.

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 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.

We have expended significant time and money on the security of our facilities and on our information technology 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.

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.

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 $94 in the three months ended March 31, 2013, demonstrating the inherent volatility in the market. The average Brent oil price per bbl was $111.67 in 2012 and $112.51 in the three months ended March 31, 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 three months ended March 31, 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.

Date: May 6, 2013	/s/ Dana Coffield By: Dana Coffield Chief Executive Officer and President (Principal Executive Officer)
Date: May 6, 2013	/s/ James Rozon By: James Rozon Chief Financial Officer (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	Seventh Amendment to Credit Agreement, dated as of January 17, 2013, among Solana Resources Limited, Gran Tierra Energy Inc., Wells Fargo Bank, National Association, and the Lenders.	Incorporated by reference to Exhibit 10.71 to the Annual Report on Form 10-K for the year ended December 31, 2012, and filed with the SEC on February 26, 2013 (SEC File No. 001-34018).
10.2	Addendum No. 3 to the Transportation Agreement between Gran Tierra Energy	Incorporated by reference to Exhibit 10.72 to the Annual Report on Form 10-K for the year ended December 31,

	Colombia, Ltd. and Ecopetrol S.A.	2012, and filed with the SEC on February 26, 2013 (SEC File No. 001-34018).
10.3	Addendum No. 3 to the Transportation Agreement between Petrolifera Petroleum (Colombia) Ltd. and Ecopetrol S.A.	Incorporated by reference to Exhibit 10.73 to the Annual Report on Form 10-K for the year ended December 31, 2012, and filed with the SEC on February 26, 2013 (SEC File No. 001-34018).
10.4	Notice dated February 15, 2013, from Wells Fargo Bank that the borrowing base amount for the Solana Resources Ltd credit facility has been increased and the increase is effective.	Incorporated by reference to Exhibit 10.74 to the Annual Report on Form 10-K for the year ended December 31, 2012, and filed with the SEC on February 26, 2013 (SEC File No. 001-34018).
10.5	2012 Executive Officer Cash Bonus Compensation and 2013 Cash Compensation Arrangements.	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 19, 2013, with respect to 2012 Cash Bonus Compensation and 2012 Cash Compensation Arrangements (SEC File No. 001-34018).
10.6	Addendum No. 2 to the Transportation Agreement between Petrolifera Petroleum (Colombia) Ltd. and Ecopetrol S.A.	Filed herewith.

10.7	Amendment to Executive Employment Agreement, dated February 21, 2003, between Gran Tierra Energy Brasil Ltda. and Julio Moreira. *	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.