GRAN TIERRA ENERGY, INC.
Form 10-Q
August 07, 2012

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

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

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2012

OR

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

FOR THE TRANSITION PERIOD FROM __________ TO __________

Commission file number 001-34018

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

Nevada (State or other jurisdiction of incorporation or organization)	98-0479924 (I.R.S. employer identification number)
300, 625 11 Avenue S.W. Calgary, Alberta, Canada (Address of principal executive offices)	T2R 0E1 (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 Web site, 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 August 2, 2012, the following numbers of shares of the registrant's capital stock were outstanding: 268,043,064 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 6,223,810 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 7,421,891 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

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Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Six Months Ended June 30, 2012

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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 (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 variations 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	BOPD	barrels of oil per day
Mbbl	thousand barrels	Mcf	thousand cubic feet
MMbbl	million barrels	MMcf	million cubic feet
BOE	barrels of oil equivalent	Bcf	billion cubic feet
MMBOE	million barrels of oil equivalent	NGL	natural gas liquids
BOEPD	barrels of oil equivalent per day	NAR	net after royalty

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 farmout transactions. Royalties include payments to governments on the production of oil and gas, either in kind or in cash. Royalties also include overriding royalties paid to third parties. Our reserves, production volumes and sales are reported net after deduction of royalties. Production volumes are also reported net of inventory adjustments. Farm-in or farmout 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 farmout by the seller of the working interest. Payment in a farm-in or farmout 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 inexpensive way of gathering data over large regions.

Seismic data is used by oil and natural gas companies as their 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 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 purposes of increasing or restoring production. It could include well deepening, plugging portions of the well, working with cementing, scale removal, acidizing, fracture stimulation, changing tubulars or installing/changing equipment to provide artificial lift.

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

- Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
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Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

iii. Where direct observation from well penetrations has defined a highest known oil 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

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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 highest known oil (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.

PART 1

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
REVENUE AND OTHER INCOME				
Oil and natural gas sales	$114,542	$161,664	$269,790	$283,960
Interest income	608	456	1,311	679
	115,150	162,120	271,101	284,639
EXPENSES				
Operating	27,333	23,160	51,820	39,556
Depletion, depreciation, accretion and impairment (Note 5)	32,571	46,965	92,938	110,322
General and administrative	17,599	16,410	33,498	30,048
Equity tax (Note 8)	—	221	—	8,271
Financial instruments gain (Notes 3 and 6)	—	(1,292)	—	(1,522)
Gain on acquisition (Note 3)	—	2,601	—	(21,699)
Foreign exchange loss	4,807	14,495	29,182	19,694
	82,310	102,560	207,438	184,670
INCOME BEFORE INCOME TAXES	32,840	59,560	63,663	99,969
Income tax expense (Note 8)	(19,736)	(27,993)	(50,872)	(54,689)
NET INCOME AND COMPREHENSIVE INCOME	13,104	31,567	12,791	45,280
RETAINED EARNINGS, BEGINNING OF PERIOD	184,701	71,810	185,014	58,097
RETAINED EARNINGS, END OF PERIOD	$197,805	$103,377	$197,805	$103,377
NET INCOME PER SHARE — BASIC	$0.05	$0.11	$0.05	$0.17
NET INCOME PER SHARE — DILUTED	$0.05	$0.11	$0.05	$0.16
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	280,714,786	277,297,728	279,726,434	269,159,453
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	284,141,287	284,451,536	283,500,228	277,530,126

(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)

	June 30, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$128,528	$351,685
Restricted cash	4,034	1,655
Accounts receivable	95,004	69,362
Inventory (Note 5)	27,055	7,116
Taxes receivable	19,267	21,485
Prepaids	3,444	3,597
Deferred tax assets (Note 8)	3,223	3,029
Total Current Assets	280,555	457,929
Oil and Gas Properties (using the full cost method of accounting)		
Proved	665,346	618,982
Unproved	425,922	417,868
Total Oil and Gas Properties	1,091,268	1,036,850
Other capital assets	8,875	7,992
Total Property, Plant and Equipment (Note 5)	1,100,143	1,044,842
Other Long-Term Assets		
Restricted cash	33,854	13,227
Deferred tax assets (Note 8)	7,974	4,747
Other long-term assets	9,299	3,454
Goodwill	102,581	102,581
Total Other Long-Term Assets	153,708	124,009
Total Assets	$1,534,406	$1,626,780
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$51,556	$82,189
Accrued liabilities	55,101	66,832
Taxes payable	13,117	95,482
Asset retirement obligation (Note 7)	167	326
Total Current Liabilities	119,941	244,829
Long-Term Liabilities		
Deferred tax liability (Note 8)	196,241	186,799
Equity tax payable (Note 8)	5,294	6,484
Asset retirement obligation (Note 7)	12,504	12,343
Other long-term liabilities	2,119	2,007
Total Long-Term Liabilities	216,158	207,633
Commitments and Contingencies (Note 9)		
Shareholders' Equity		
	7,986	7,510

Common shares (Note 6) (267,819,245 and 264,256,159 common shares and 13,869,520 and 13,869,520 exchangeable shares, par value $0.001 per share, issued and outstanding as at June 30, 2012 and December 31, 2011, respectively)		
Additional paid in capital	992,516	980,014
Warrants (Note 6)	—	1,780
Retained earnings	197,805	185,014
Total Shareholders' Equity	1,198,307	1,174,318
Total Liabilities and Shareholders' Equity	$1,534,406	$1,626,780

(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)

	Six Months Ended June 30,	
	2012	2011
Operating Activities		
Net income	$12,791	$45,280
Adjustments to reconcile net income to net cash (used in) provided by operating activities:		
Depletion, depreciation, accretion and impairment	92,938	110,322
Deferred taxes (Note 8)	(10,050)	(5,406)
Stock-based compensation (Note 6)	6,922	5,945
Unrealized gain on financial instruments (Note 3)	—	(1,354)
Unrealized foreign exchange loss	16,164	16,102
Settlement of asset retirement obligation (Note 7)	(404)	(309)
Equity tax	(1,785)	6,251
Gain on acquisition (Note 3)	—	(21,699)
Net change in assets and liabilities from operating activities		
Accounts and other receivables	(17,668)	(100,955)
Inventory	(13,485)	(213)
Prepaids	154	(211)
Accounts payable and accrued and other liabilities	(28,567)	(2,508)
Taxes receivable and payable	(82,262)	(18,120)
Net cash (used in) provided by operating activities	(25,252)	33,125
Investing Activities		
Increase in restricted cash	(23,006)	(8,139)
Additions to property, plant and equipment	(178,644)	(182,408)
Proceeds from disposition of oil and gas property (Note 5)	—	3,253
Cash acquired on acquisition (Note 3)	—	7,747
Proceeds on sale of asset-backed commercial paper (Note 3)	—	22,679
Net cash used in investing activities	(201,650)	(156,868)
Financing Activities		
Settlement of bank debt (Note 3)	—	(22,853)
Proceeds from issuance of common shares	3,745	2,523
Net cash provided by (used in) financing activities	3,745	(20,330)
Net decrease in cash and cash equivalents	(223,157)	(144,073)
Cash and cash equivalents, beginning of period	351,685	355,428
Cash and cash equivalents, end of period	$128,528	$211,355
Cash	$78,929	$135,142
Term deposits	49,599	76,213
Cash and cash equivalents, end of period	$128,528	$211,355
Supplemental cash flow disclosures:		
Cash paid for interest	$—	$1,344

Cash paid for income taxes	$139,482	$64,205
Non-cash investing activities:		
Non-cash working capital related to property, plant and equipment, end of period	$18,447	$39,118

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30, 2012	Year Ended December 31, 2011
Share Capital		
Balance, beginning of period	$7,510	$4,797
Issue of common shares	476	2,713
Balance, end of period	7,986	7,510
Additional Paid in Capital		
Balance, beginning of period	980,014	821,781
Issue of common shares	2,902	142,109
Exercise of warrants (Note 6)	1,590	411
Expiry of warrants (Note 6)	190	—
Exercise of stock options (Note 6)	367	1,990
Stock-based compensation (Note 6)	7,453	13,723
Balance, end of period	992,516	980,014
Warrants		
Balance, beginning of period	1,780	2,191
Exercise of warrants (Note 6)	(1,590)	(411)
Expiry of warrants (Note 6)	(190)	—
Balance, end of period	—	1,780
Retained Earnings		
Balance, beginning of period	185,014	58,097
Net income	12,791	126,917
Balance, end of period	197,805	185,014
Total Shareholders' Equity	$1,198,307	$1,174,318

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Condensed Consolidated Financial Statements (Unaudited)

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, 2011 included in the Company’s 2011 Annual Report on Form 10-K, filed with the Securities and Exchange Commission (“SEC”) on February 27, 2012.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2011 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as disclosed below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued. Certain amounts for 2011 have been reclassified to conform to the 2012 presentation. The reclassifications had no effect on net income.

Revenue Recognition

Revenue from the production of oil and natural gas is recognized when title passes to the customer and when collection of the revenue is reasonably assured. On February 1, 2012, the sales point for the majority of the Company’s Colombian oil sales in the Putumayo basin changed. Gran Tierra’s customer, Ecopetrol S.A. (“Ecopetrol”), now takes title at the Port of Tumaco on the Pacific coast of Colombia rather than at the entry into the Ecopetrol-operated Trans-Andean oil pipeline (“the OTA pipeline”) at the Orito station in the Putumayo basin.

Inventory
Inventory consists of oil in tanks and pipelines and supplies and is valued at the lower of cost or market value. The cost of inventory is determined using the weighted average method. Oil inventories include expenditures incurred to produce, upgrade and transport the product to the storage facilities and includes operating, depletion and depreciation expenses and cash royalties.

Adopted Accounting Pronouncements

Goodwill

In September 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2011-08, "Intangibles – Goodwill and Other (Topic 350)." The update is intended to simplify how entities test goodwill for impairment. The update permits entities to assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. This ASU was effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2011. The implementation of this update did not materially impact the Company's consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

Disclosure about Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU 2011-11, "Balance Sheet – Disclosure about Offsetting Assets and Liabilities (Topic 210)." The update requires an entity to disclose information about offsetting assets and liabilities and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. This ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after January 1, 2013. The implementation of this update is not expected to materially impact the Company’s disclosure.

3. Business Combination

On March 18, 2011 (the “Acquisition Date”), Gran Tierra completed its acquisition of all the issued and outstanding common shares and warrants of Petrolifera Petroleum Limited (“Petrolifera”), a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011 (the “Arrangement”). Petrolifera is a Calgary based oil, natural gas and natural gas liquids exploration, development and production company active in Argentina, Colombia and Peru. The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petrolifera shareholders on March 17, 2011 and by the Court of Queen's Bench of Alberta on March 18, 2011.

Under the Arrangement, Petrolifera shareholders received, for each Petrolifera share held, 0.1241 of a share of Gran Tierra common stock, and Petrolifera warrant holders received, for each Petrolifera warrant held, 0.1241 of a warrant (a "Replacement Warrant") to purchase a share of Gran Tierra common stock at an exercise price of $9.67 Canadian (“CDN”) dollars per share. The Replacement Warrants expired unexercised on August 28, 2011.

Gran Tierra acquired all the issued and outstanding Petrolifera shares and warrants through the issuance of 18,075,247 Gran Tierra common shares, par value $0.001, and 4,125,036 Replacement Warrants. Upon completion of the transaction on the Acquisition Date, Petrolifera became an indirect wholly-owned subsidiary of Gran Tierra. On a diluted basis, upon the closing of the Arrangement, Petrolifera and Gran Tierra security holders owned approximately 6.6% and 93.4% of the Company, respectively, immediately following the transaction. The total consideration for the transaction was approximately $143 million.

The fair value of Gran Tierra’s common shares was determined as the closing price of the common shares of Gran Tierra as at the Acquisition Date.

The fair value of the Replacement Warrants was estimated on the Acquisition Date using the Black-Scholes option pricing model with the following assumptions:

Exercise price (CDN dollars per warrant)	$9.67	
Risk-free interest rate	1.3	%
Expected life	0.45	Years
Volatility	44	%
Expected annual dividend per share	Nil	
Estimated fair value per warrant (CDN dollars)	$0.32	

The acquisition is accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera’s assets acquired and liabilities assumed are recognized at their fair values as at the Acquisition Date and the results of Petrolifera have been consolidated with those of Gran Tierra from that date.

The following table shows the allocation of the consideration transferred based on the fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)	
Consideration Transferred:	
Common shares issued net of share issue costs	$141,690
Replacement Warrants	1,354
	$143,044
Allocation of Consideration Transferred:	
Oil and gas properties	
Proved	$58,457
Unproved	161,278
Other long-term assets	4,417
Net working capital (including cash acquired of $7.7 million and accounts receivable of $6.4 million)	(17,223)
Asset retirement obligation	(4,901)
Bank debt	(22,853)
Other long-term liabilities	(14,432)
Gain on acquisition	(21,699)
	$143,044

As shown above, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized a gain of $21.7 million, which was reported as “Gain on acquisition”, in the condensed consolidated statement of operations. The gain reflected the impact on Petrolifera’s pre-acquisition market value of a lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects. Subsequent to the initial allocation of the consideration reported in the first quarter of 2011, further assessment of Petrolifera’s tax position resulted in a reduction of the gain on acquisition to $21.7 million from $24.3 million previously reported. A corresponding adjustment was made to the net working capital deficiency assumed.

As part of the assets acquired and included in the net working capital in the allocation of the consideration transferred, the Company assigned $22.5 million in fair value to investments in notes that Petrolifera received in exchange for asset-backed commercial paper (“ABCP”) with a face value of $31.3 million. On March 28, 2011, these notes were sold to an unrelated party for proceeds of $22.7 million after the associated line of credit was settled. When combined with the gain arising on expiry of the Replacement Warrants, the financial instruments gain for the six months ended June 30, 2011 was $1.5 million.

The associated ABCP line of credit that Gran Tierra assumed was with a Canadian chartered bank, to a maximum of CDN$23.2 million with an initial expiry in April 2012. Gran Tierra settled this line of credit immediately after the completion of the acquisition of Petrolifera for the face value of CDN$22.5 million in borrowings plus accrued interest.

Also upon the acquisition of Petrolifera, Gran Tierra assumed a second line of credit agreement (“Second ABCP line of credit”) with the same Canadian chartered bank to a maximum of CDN$5.0 million, which was fully drawn as at the Acquisition Date. This Second ABCP line of credit, which expired on April 8, 2011, was secured by ineligible master asset vehicles Classes 1 & 2 (“MAV IA 1 & 2”) notes with a face value of $6.6 million. Gran Tierra retained the option to settle the Second ABCP line of credit of CDN$5.0 million through delivery to the lender of the MAV IA 1 & 2 notes. Subsequent to the acquisition, Gran Tierra elected to record this second line of credit at fair value and planned at that time to settle the debt through delivery of the MAV IA 1 & 2 notes. Accordingly, a value of $nil was recorded for the debt upon its acquisition. Gran Tierra settled such borrowings by delivery of the MAV IA 1 & 2 notes on April 8, 2011.

Gran Tierra also assumed a reserve-backed credit facility upon the Petrolifera acquisition with an outstanding balance of $31.3 million. The amount outstanding under this credit facility was included as part of net working capital in the allocation of consideration transferred. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries. The outstanding balance was repaid when the Argentine restriction preventing its repayment expired on August 5, 2011.

Interest expense on the reserve-backed credit facility for the 104-day period from the Acquisition Date to June 30, 2011 was $0.8 million. This amount is recorded on the condensed consolidated statements of operations as part of general and administrative ("G&A") expenses.

Pro forma results for the three and six months ended June 30, 2011 are shown below, as if the acquisition had occurred on January 1, 2010. Pro forma results are not indicative of actual results or future performance.

(Thousands of U.S. Dollars except per share amounts)	Six Months Ended June 30, 2011
Revenue and other income	$293,834
Net income	$12,457
Net income per share - basic	$0.05
Net income per share - diluted	$0.04

The supplemental pro forma earnings of Gran Tierra for the six months ended June 30, 2011 were adjusted to exclude $4.4 million of acquisition costs recorded in G&A expenses and the $21.7 million gain on acquisition because they are not expected to have a continuing impact on Gran Tierra's results of operations. The condensed consolidated statement of operations for the six months ended June 30, 2011 included revenue of $10.9 million from Petrolifera for the period subsequent to the Acquisition Date. Net income from Petrolifera for the period from the Acquisition Date to June 30, 2011 was not material.

4. 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 and Peru based on geographic organization. The level of activity in Brazil was not significant at June 30, 2012 or December 31, 2011; however, the Company has separately disclosed its results of operations in Brazil as a reportable segment. 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 segmented results include the operations of Petrolifera subsequent to March 18, 2011, the Acquisition Date (Note 3).

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

	Three Months Ended June 30, 2012					
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	$92,018	$21,482	$—	$1,042	$—	$114,542
Interest income	223	39	—	272	74	608
Depletion, depreciation, accretion and impairment	23,084	7,990	991	266	240	32,571
Depletion, depreciation, accretion and impairment - per unit of production	24.61	23.78	—	23.14	—	25.34
Income (loss) before income taxes	42,481	1,268	(2,573)	(1,228)	(7,108)	32,840
Segment capital expenditures	$42,247	$2,739	$16,007	$5,442	$169	$66,604

	Three Months Ended June 30, 2011					
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	$148,473	$12,857	$—	$334	$—	$161,664
Interest income	158	28	134	—	136	456
Depletion, depreciation, accretion and impairment	39,609	5,505	1,530	156	165	46,965
Depletion, depreciation, accretion and impairment - per unit of production	28.49	21.45	—	38.87	—	28.45
Income (loss) before income taxes	73,729	(3,099)	(2,371)	(1,376)	(7,323)	59,560
Segment capital expenditures	$54,216	$7,138	$11,287	$28,287	$561	$101,489

	Six Months Ended June 30, 2012					
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	$230,651	$36,851	$—	$2,288	$—	$269,790
Interest income	427	86	15	567	216	1,311
Depletion, depreciation, accretion and impairment	55,370	13,915	1,106	22,074	473	92,938
Depletion, depreciation, accretion and impairment - per unit of production	25.29	23.35	—	919.14	—	33.08
Income (loss) before income taxes	102,601	791	(3,300)	(23,297)	(13,132)	63,663
Segment capital expenditures	$62,596	$16,844	$32,662	$41,698	$395	$154,195

	Six Months Ended June 30, 2011					
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	$265,777	$17,849	$—	$334	$—	$283,960

Interest income	245	28	134	11	261	679
Depletion, depreciation, accretion and impairment	69,645	6,652	33,463	252	310	110,322
Depletion, depreciation, accretion and impairment - per unit of production	26.75	18.85	—	62.80	—	37.27
Income (loss) before income taxes	131,615	(3,529)	(34,996)	(2,744)	9,623	99,969
Segment capital expenditures (1)	$96,480	$18,760	$25,574	$28,674	$1,104	$170,592

(1) Net of proceeds from the farm out of a 50% interest in the Santa Victoria Block in Argentina in March 2011 (Note 5).

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.

The Company has one significant customer in Colombia, Ecopetrol. Sales to Ecopetrol accounted for 75% and 88% of the Company's revenues for the three months ended June 30, 2012 and 2011, and 81% and 89% for the six months ended June 30, 2012 and 2011, respectively.

The Company has two significant customers in Argentina, Shell C.A.P.S.A. ("Shell") and Refineria del Norte S.A. ("Refiner"). Sales to Shell and Refiner accounted for 2% and 8% of the Company's oil and natural gas sales for the three months ended June 30, 2012, and 3% and 5% for the six months ended June 30, 2012, respectively. In the three months ended June 30, 2011, sales to Shell and Refiner accounted for 7% and 2%, and in the six months ended June 30, 2011, accounted for 4% and 3%, respectively.

(Thousands of U.S. Dollars)	As at June 30, 2012					
	Colombia	Argentina	Peru	Brazil	All Other	Total
Property, plant and equipment	$817,431	$132,190	$65,860	$81,546	$3,116	$1,100,143
Goodwill	102,581	—	—	—	—	102,581
Other assets	170,076	46,260	11,712	11,719	91,915	331,682
Total Assets	$1,090,088	$178,450	$77,572	$93,265	$95,031	$1,534,406

	As at December 31, 2011					
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	All Other	Total
Property, plant and equipment	$816,396	$129,072	$34,305	$61,875	$3,194	$1,044,842
Goodwill	102,581	—	—	—	—	102,581
Other assets	269,843	34,672	9,597	17,065	148,180	479,357
Total Assets	$1,188,820	$163,744	$43,902	$78,940	$151,374	$1,626,780

5. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

	As at June 30, 2012			As at December 31, 2011		
(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	$1,325,336	$(659,990)	$665,346	$1,181,503	$(562,521)	$618,982
Unproved	425,922	—	425,922	417,868	—	417,868
	1,751,258	(659,990)	1,091,268	1,599,371	(562,521)	1,036,850
Furniture and fixtures and leasehold improvements	7,649	(4,551)	3,098	6,973	(4,002)	2,971
Computer equipment	10,076	(4,968)	5,108	8,443	(4,174)	4,269
Automobiles	1,295	(626)	669	1,295	(543)	752
	$1,770,278	$(670,135)	$1,100,143	$1,616,082	$(571,240)	$1,044,842

Total Property, Plant and Equipment

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Depletion and depreciation expense on property, plant and equipment for the six months ended June 30, 2012 was $77.8 million (six months ended June 30, 2011 - $77.2 million) and for the three months ended June 30, 2012 was $35.1 million (three months ended June 30, 2011 - $45.0 million). A portion of depletion and depreciation expense was recorded as inventory in each period.

On August 7, 2012, the Company announced that Costayaco Field reserves as of June 30, 2012, net after royalty ("NAR"), calculated in accordance with SEC rules, increased, after production, from year-end 2011 reserves as follows: total proved reserves increased to approximately 19.6 million barrels of oil. The reserve revisions were due to a successful waterflood program and reservoir management.

On June 5, 2012, the Company received regulatory approval of a farm-in agreement on a block in Colombia. This approval triggered a payment of $21.1 million related to drilling costs for a previously drilled oil exploration well, which was recorded as a capital expenditure in the second quarter of 2012.

Effective June 1, 2012, the Company entered into an agreement to acquire the remaining 40% working interest in a block in Peru. The block is an unproved property. Purchase consideration was $5.4 million and was recorded as a capital expenditure in the three months ended June 30, 2012. The agreement is subject to government approval.

On August 26, 2010, the Company entered into an agreement to acquire a 70% participating interest in four blocks in Brazil. With the exception of one block which has a producing well, the remaining blocks are unproved properties. The agreement was effective September 1, 2010, subject to regulatory approvals, and the transaction was completed on June 15, 2011. Purchase consideration was $40.1 million and was recorded as a capital expenditure in 2011 and 2010. The 70% share of all benefits and costs with respect to the period between the effective date and the completion of the transaction were an adjustment to the consideration paid for the four blocks. On January 20, 2012, the Company entered into an agreement to acquire the remaining 30% participating interest in these four blocks. The completion of the transaction is subject to regulatory approval.

In September 2011, the Company announced two farmout agreements with Statoil do Brasil Ltda. ("Statoil") in a joint venture with PetróleoBrasileiro S.A., in Brazil’s deepwater offshore Camamu-Almada Basin, pursuant to which, the Company would receive an assignment of a non-operated 10% working interest in Block BM-CAL-7 and a non-operated 15% working interest in Block BM-CAL-10. Both blocks are located in the Camamu Basin, offshore Bahia, Brazil.

During the first quarter of 2012, the Company received regulatory approval from Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") for the Block BM-CAL-7 farmout agreement. Purchase consideration of $0.7 million was paid and the assignment became effective on April 3, 2012. This block is an unproved property.

On February 17, 2012, in accordance with the terms of the farmout agreement for 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 farmout agreement has terminated and the Company will not receive any interest in the block. Pursuant to the farmout 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 farmout agreement. The notice of withdrawal was a trigger for payment of amounts that would otherwise have been due if the farmout agreement had closed and the Company had acquired a participating interest. In the three months ended March 31, 2011, 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 farmout agreement in the first quarter of 2012.

In the six months ended June 30, 2011, the Company recorded a ceiling test impairment loss in the Company’s Peru cost center of $33.4 million (three months ended June 30, 2011 - $1.5 million). This impairment charge related to seismic and drilling costs from a dry well.

In March 2011, the Company recorded proceeds of $3.3 million from the farmout of a 50% interest in the Santa Victoria Block in Argentina to Apache Corporation.

The amounts capitalized in each of the Company's cost centers during the six months ended June 30, 2012 and 2011, respectively, were as follows:

	Six Months Ended June 30, 2012				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	$4,219	$1,915	$1,623	$2,107	$9,864
Capitalized stock-based compensation	$190	$148	$—	$193	$531

	Six Months Ended June 30, 2011				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	$4,121	$1,022	$824	$228	$6,195
Capitalized stock-based compensation	$189	$114	$—	$—	$303

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. As at June 30, 2012, the Company had $261.9 million (December 31, 2011 - $274.8 million) of unproved assets in Colombia, $49.9 million (December 31, 2011 - $57.0 million) of unproved assets in Argentina, $65.2 million (December 31, 2011 - $33.7 million) of unproved assets in Peru, and $48.9 million (December 31, 2011 - $52.4 million) of unproved assets in Brazil for a total of $425.9 million (December 31, 2011 - $417.9 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.

Inventories

As at June 30, 2012, oil and supplies inventories were $24.6 million and $2.5 million, respectively (December 31, 2011 - $4.7 million and $2.4 million, respectively).

6. 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 June 30, 2012, outstanding share capital consists of 267,819,245 common voting shares of the Company, 7,645,710 exchangeable shares of Gran Tierra Exchange Co., automatically exchangeable on November 14, 2013, and 6,223,810 exchangeable shares of Goldstrike Exchange Co., automatically exchangeable on November 10, 2012. The exchangeable shares of Gran Tierra Exchange Co., were issued upon acquisition of Solana Resources Limited (“Solana”). The exchangeable shares of Gran Tierra Goldstrike Inc. were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. Each exchangeable share is exchangeable into one common voting share of the Company.

The holders of common voting shares 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 voting shares have no pre-emptive rights, no conversion rights, and there are no redemption provisions applicable to the common voting shares. Holders of exchangeable shares have substantially the same rights as holders of common voting shares.

Stock Options

For the six months ended June 30, 2012, the stock-based compensation expense was $7.4 million (six months ended June 30, 2011- $6.2 million) of which $6.3 million (six months ended June 30, 2011 - $5.4 million) was recorded in G&A expenses, $0.6 million was recorded in operating expense (six months ended June 30, 2011 – $0.5 million) and $0.5 million was capitalized as part of exploration and development costs (six months ended June 30, 2011 – $0.3 million).

For the three months ended June 30, 2012, the stock-based compensation expense was $4.0 million (three months ended June 30, 2011- $2.7 million) of which $3.4 million (three months ended June 30, 2011 - $2.2 million) was recorded in G&A expenses, $0.3 million was recorded in operating expense (three months ended June 30, 2011 – $0.3 million) and $0.3 million was capitalized as part of exploration and development costs (three months ended June 30, 2011 – $0.2 million).

At June 30, 2012, there was $14.3 million (December 31, 2011 - $11.7 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next three years.

On June 27, 2012, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the number of shares of common stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares. The following table provides information about stock option activity for the six months ended June 30, 2012:

	Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2011	12,864,002	$4.90
Granted in 2012	3,260,650	5.80
Exercised in 2012	(267,673)	(3.14)
Forfeited in 2012	(197,314)	(6.99)
Balance, June 30, 2012	15,659,665	$5.09

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model based on assumptions noted in the following table.

	Three Months Ended June 30, 2012
Dividend yield (per share)	nil
Volatility	75%
Risk-free interest rate	0.4%
Expected term	4-6 years

The weighted average grant date fair value for options granted in the six months ended June 30, 2012 was $5.80 (six months ended June 30, 2011 - $5.07) and for the three months ended June 30, 2012 was $5.29 (three months ended June 30, 2011 - $7.28) .

Warrants

At December 31, 2011, the Company had 6,298,230 warrants outstanding to purchase 3,149,115 common shares for $1.05 per share, expiring between June 20, 2012 and June 30, 2012. During the six months ended June 30, 2012, 2,775,334 common shares were issued upon the exercise of 5,550,668 warrants (six months ended June 30, 2011, 525,817 common shares were issued upon the exercise of 1,051,634 warrants), 26,190 common shares were issued with 7,143 shares withheld in lieu of a cashless exchange upon the exercise of 66,666 warrants, and 680,896 warrants expired unexercised.

The Company issued 4,125,036 Replacement Warrants in connection with its acquisition of Petrolifera during March 2011 (Note 3). The Replacement Warrants expired unexercised in August 2011.The fair value of the Replacement

Warrants as of June 30, 2011, was determined using the Black-Scholes option pricing model with the following assumptions:

Exercise price (CDN dollars per warrant)	$9.67	
Risk-free interest rate	1.2	%
Expected life	0.16	Years
Volatility	42	%
Expected annual dividend per share	Nil	
Estimated fair value per warrant (CDN dollars)	$0.003	

During the three months ended June 30, 2011, a financial instruments gain resulting from the change in fair value of the Replacement Warrants of $1.3 million was recorded.

Weighted Average Shares Outstanding

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Weighted average number of common and exchangeable shares outstanding	280,714,786	277,297,728	279,726,434	269,159,453
Shares issuable pursuant to warrants	170,145	2,728,361	339,495	2,789,122
Shares issuable pursuant to stock options	5,942,583	5,191,288	6,078,405	6,079,268
Shares to be purchased from proceeds of stock options	(2,686,227)	(765,841)	(2,644,106)	(497,717)
Weighted average number of diluted common and exchangeable shares outstanding	284,141,287	284,451,536	283,500,228	277,530,126

For the three month period ended June 30, 2012, 9,726,917 options were excluded from the diluted income per share calculation as the instruments were anti-dilutive (for the three months ended June 30, 2011, 3,815,996 options and 4,125,036 Replacement Warrants were excluded from the diluted income per share calculation for the same reason).

For the six month period ended June 30, 2012, 9,731,230 options were excluded from the diluted income per share calculation as the instruments were anti-dilutive (for the six months ended June 30, 2011, 3,219,996 options and 4,125,036 Replacement Warrants were excluded from the diluted income per share calculation).

7. Asset Retirement Obligation

As at June 30, 2012, the Company’s asset retirement obligation comprised a Colombian obligation in the amount of $5.9 million (December 31, 2011 - $5.5 million), an Argentine obligation in the amount of $6.1 million (December 31, 2011 - $6.7 million), a Brazilian obligation in the amount of $0.5 million (December 31, 2011 - $0.5 million) and a Peruvian obligation in the amount of $0.2 million (December 31, 2011 - $nil). As at June 30, 2012, the undiscounted asset retirement obligation was $32.6 million (December 31, 2011 - $29.9 million). 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. Changes in the carrying amounts of the asset retirement obligation associated with the Company’s oil and natural gas properties were as follows:

	Six Months Ended	Year Ended
(Thousands of U.S. Dollars)	2012	2011
Balance, beginning of period	$12,669	$4,807
Settlements	(404)	(345)
Disposal	—	(172)
Liability incurred	513	867
Liability assumed in a business combination (Note 3)	—	4,901
Foreign exchange	9	17
Accretion	500	673
Revisions in estimated liability	(616)	1,921
Balance, end of period	$12,669	$12,669
Asset retirement obligation - current	$167	$326
Asset retirement obligation - long-term	12,504	12,343
Balance, end of period	$12,671	$12,669

8. 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:

	Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2012	2011
Income before income taxes	$63,663	$99,969
	35 %	35 %
Income tax expense expected	22,282	34,989
Foreign currency translation adjustments	8,101	4,956
Impact of foreign taxes	(86)	(3,134)
Stock-based compensation	2,326	1,825
Increase in valuation allowance	5,457	24,065
Branch and other foreign loss pick-up in the United States and Canada	(2,159)	(2,898)
Non-deductible third party royalty in Colombia	7,140	4,115
Non-taxable gain on acquisition	—	(7,595)
Other permanent differences	7,811	(1,634)
Total income tax expense	$50,872	$54,689
Current income tax	60,922	63,439
Deferred tax recovery	(10,050)	(8,750)
Total income tax expense	$50,872	$54,689

For the six months ended June 30, 2012, other permanent differences include $8.2 million of loss adjustments which are fully offset by a change in the valuation allowance.

	As at	
(Thousands of U.S. Dollars)	June 30, 2012	December 31, 2011
Deferred Tax Assets		
Tax benefit of loss carryforwards	$71,805	$63,910
Tax basis in excess of book basis	15,261	17,065
Foreign tax credits and other accruals	27,445	27,164
Capital losses	5,510	2,433
Deferred tax assets before valuation allowance	120,021	110,572
Valuation allowance	(108,824)	(102,796)
	$11,197	$7,776
Deferred tax assets - current	$3,223	$3,029
Deferred tax assets - long-term	7,974	4,747
	11,197	7,776
Deferred Tax Liabilities		
Long-term - book value in excess of tax basis	(196,241)	(186,799)
Net Deferred Tax Liabilities	$(185,044)	$(179,023)

As at June 30, 2012, the Company had operating loss carryforwards of $388.8 million (December 31, 2011 - $361.6 million) and capital losses of $36.6 million (December 31, 2011 – $13.7 million) before valuation allowance. Of these losses, $391.9 million (December 31, 2011 - $339.8 million) were losses generated by the foreign subsidiaries of the Company, including $119.2 million relating to a Barbadian subsidiary taxable at 1.75% which are expected to be extinguished by the end of 2012. In certain jurisdictions, the operating loss carryforwards expire between 2013 and 2032 and the capital losses expire between 2013 and 2017, while certain other jurisdictions allow operating losses to be carried forward indefinitely. Of the total operating loss carryforwards, $3.5 million will expire in 2013.

As at June 30, 2012, the total amount of Gran Tierra's unrecognized tax benefit was approximately $20.5 million (December 31, 2011 - $20.5 million), a portion of which, if recognized, would affect the Company's effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the condensed consolidated statement of operations. As at June 30, 2012, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the condensed consolidated balance sheet was approximately $1.6 million (December 31, 2011 - $1.6 million). The Company had no material interest or penalties included in the condensed consolidated statement of operations for the three and six months ended June 30, 2012 and 2011, respectively.

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

	Six Months Ended June 30,	
	2012	2011
(Thousands of U.S. Dollars)		
Unrecognized tax benefit at January 1	$20,500	$4,175
Changes for positions relating to prior year	—	(257)
Additions to tax position related to the current year	—	9,190
Unrecognized tax benefit at June 30	$20,500	$13,108

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 2011 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

Equity tax for the six months ended June 30, 2011 of $8.3 million represented a Colombian tax of 6% 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 at June 30, 2012 and December 31, 2011 was also partially related to an equity tax liability assumed upon the acquisition of Petrolifera.

9. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of June 30, 2012:

	As at June 30, 2012 Payments Due in Period				
	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
(Thousands of U.S. Dollars)					
Oil transportation services	$32,560	$8,710	$7,100	$7,100	$9,650
Drilling and geological and geophysical	39,480	38,374	1,106	—	—
Completions	30,828	24,560	6,268	—	—
Facility construction	31,000	17,049	13,951	—	—
Operating leases	6,882	2,861	3,003	1,018	—
Software and telecommunication	8,093	3,685	4,408	—	—

Consulting	1,058	1,058	—	—	—
Total	$149,901	$96,297	$35,836	$8,118	$9,650

Indemnities

Corporate indemnities have been provided by the Company to directors and officers for various items including, but not limited to, all costs to settle suits or actions due to their association with the Company and its subsidiaries and/or affiliates, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The maximum amount of any potential future payment cannot be reasonably estimated.

The Company may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

Letters of credit

At June 30, 2012, the Company had provided promissory notes totaling $34.4 million (December 31, 2011 - $20.7 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contingencies

Ecopetrol and Gran Tierra Energy Colombia Ltd. ("Gran Tierra Colombia"), 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. There is a material difference in the interpretation of the procedure established in Clause 3.5 of Attachment-B of the Guayuyaco Association Contract. Ecopetrol interprets the contract to provide that the extended test production up to a value equal to 30% of the direct exploration costs of the wells is for Ecopetrol's account only and serves as reimbursement of its 30% back-in to the Guayuyaco discovery. Gran Tierra Colombia's contention is that this amount is merely the recovery of 30% of the direct exploration costs of the wells and not exclusively for the benefit of Ecopetrol. There has been no agreement between the parties, and Ecopetrol has filed a lawsuit in the Contravention Administrative Court in the District of Cauca regarding this matter. Gran Tierra Colombia filed a response on April 29, 2008 in which it refuted all of Ecopetrol's claims and requested a change of venue to the courts in Bogota. At this time no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. Ecopetrol is claiming damages of approximately $5.8 million.

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 sent notice to the ANH to initiate the dispute resolution process prescribed by the Chaza Contract. As at June 30, 2012, total cumulative production from the Moqueta field was 0.6 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $10.3 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.

Gran Tierra is subject to a third party 10% net profits interest on 50% of Gran Tierra's production from the Chaza Block that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There was a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party agreed to resolve this issue through arbitration. The arbitration was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. Gran Tierra received the arbitrator's decision on May 24, 2012. The arbitrator ruled against Gran Tierra and as a result $10.9 million became payable in relation to past production. The arbitrator's decision will also increase future net profit interests payable to this third party, but is not expected to have a material impact on future results.
Gran Tierra has several lawsuits and claims pending for which the Company currently cannot determine the ultimate result. Gran Tierra records costs as they are incurred or become probable and determinable. 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.

10. Financial Instruments, Fair Value Measurements and Credit Risk

At June 30, 2012, 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. The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these 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. At June 30, 2012, the Company did not have any financial assets or liabilities measured at fair value on the balance sheet and held no derivative instruments. The Company does not use derivative financial instruments for speculative purposes.

At June 30, 2011, the Replacement Warrants (Note 3) met the definition of a derivative. Because the exercise price of the Replacement Warrants was denominated in Canadian dollars, which is different from Gran Tierra's functional currency, the Replacement Warrants were not considered indexed to Gran Tierra's common shares and the Replacement Warrants could not be classified within equity. Therefore the Replacement Warrants were classified as a current liability on Gran Tierra's condensed consolidated balance sheet. Furthermore, these derivative instruments did not qualify as fair value hedges or cash flow hedges, and accordingly, changes in their fair value were recognized as income or expense in the condensed consolidated statement of operations with a corresponding adjustment to the fair value of derivative instruments recognized on the balance sheet. The fair value of the Replacement Warrants at June 30, 2011 was determined using Level 3 inputs (Note 6).

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 receivables. The carrying value of cash and accounts receivable reflects management's assessment of credit risk.

At June 30, 2012, 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 and six months ended June 30, 2012, the Company had one significant customer for its Colombian oil, Ecopetrol, and in Argentina the Company had two significant customers, Shell and Refiner.

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 $105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

11. Bank Debt and Credit Facilities

Effective July 30, 2010, a subsidiary of Gran Tierra, Solana, established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. 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, Gran Tierra Colombia and Solana Petroleum Exploration (Colombia) Ltd, and the Company's subsidiary in Brazil - Gran Tierra Energy Brasil Ltda. The initial committed borrowing base was $20 million. Effective August 2, 2012, the committed borrowing base was increased to $50 million. 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. Under the terms of the facility, the

Company is required to maintain and was in compliance with certain financial and operating covenants. As at June 30, 2012 and December 31, 2011, the Company had not drawn down any amounts under this facility. On May 17, 2012, BNP Paribas sold Solana's credit facility to Wells Fargo Bank National Association, as part of the sale of its North American reserve-based lending business, without any modification to the facility.

12. Related Party Transactions

On January 12, 2011, the Company entered into an agreement to sublease office space to a company of which Gran Tierra's President and Chief Executive Officer serves as an independent director. The term of the sublease runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,300 per month plus approximately $5,500 of operating and other expense.

On August 3, 2010, Gran Tierra entered into a contract related to the Peru drilling program with a company for which one of Gran Tierra's directors is a shareholder and director. During the three and six months ended June 30, 2011, $0.2 million and $2.2 million was incurred and capitalized under this contract. During the three and six months ended June 30, 2012, $nil was incurred and capitalized under this contract.

On February 1, 2009, the Company entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was $8,000 per month plus approximately $4,700 for operating and other expenses.

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 Management’s Discussion and Analysis of Financial Condition and Results of Operations included in our Annual Report on Form 10-K, filed with the U.S. Securities and Exchange Commission (“SEC”) on February 27, 2012.

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 six months ended June 30, 2012, 85% (six months ended June 30, 2011 - 94%) of our revenue and other income was generated in Colombia.

Highlights

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
Production (BOEPD) (1)	14,127	18,141	(22)	15,435	16,354	(6)
Prices Realized - per BOE	$89.10	$97.93	(9)	$96.04	$95.93	—
Revenue and Other Income ($000s)	$115,150	$162,120	(29)	$271,101	$284,639	(5)
Net Income ($000s)	$13,104	$31,567	(58)	$12,791	$45,280	(72)
Net Income Per Share - Basic	$0.05	$0.11	(55)	$0.05	$0.17	(71)
Net Income Per Share - Diluted	$0.05	$0.11	(55)	$0.05	$0.16	(69)
Funds Flow From Operations ($000s) (2)	$37,633	$88,572	(58)	$116,576	$155,132	(25)
Capital Expenditures ($000s)	$66,604	$101,489	(34)	$154,195	$170,592	(10)

	As at		
	June 30, 2012	December 31, 2011	% Change
Cash & Cash Equivalents ($000s)	$128,528	$351,685	(63)
Working Capital (including cash & cash equivalents) ($000s)	$160,614	$213,100	(25)

Property, Plant & Equipment ($000s)	$1,100,143	$1,044,842	5

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Funds Flow From Operations - Non-GAAP Measure ($000s)	2012	2011	2012	2011
Net income	$13,104	$31,567	$12,791	$45,280
Adjustments to reconcile net income to funds flow from operations				
DD&A expenses	32,571	46,965	92,938	110,322
Deferred taxes	(4,800)	(5,219)	(10,050)	(5,406)
Stock-based compensation	3,730	2,492	6,922	5,945
Unrealized gain on financial instruments	—	(1,292)	—	(1,354)
Unrealized foreign exchange (gain) loss	(5,187)	11,644	16,164	16,102
Settlement of asset retirement obligation	—	(305)	(404)	(309)
Equity tax	(1,785)	119	(1,785)	6,251
Gain on acquisition	—	2,601	—	(21,699)
Funds flows from operations	$37,633	$88,572	$116,576	$155,132

Highlights

- Effective June 30, 2012, Costayaco Field reserves, NAR, calculated in accordance with SEC rules, increased, adjusted for production from the first half of 2012, from year-end 2011 reserves as follows: total proved reserves increased 33% to approximately 19.6 MMbbl, total proved plus probable reserves increased 35% to approximately 22.2 MMbbl, and total proved plus probable plus possible reserves increased 18% to approximately 25.6 MMbbl.

- In the second quarter of 2012, oil and natural gas production, NAR and adjusted for inventory changes, averaged 14,127 BOEPD, a decrease of 22% over the second quarter of 2011. The decrease was primarily due to oil delivery restrictions during disruptions in the Ecopetrol-operated Trans-Andean oil pipeline ("the OTA pipeline") in Colombia, partially offset by production from new producing wells in Colombia. For the first half of 2012, oil and gas production, NAR and adjusted for inventory changes, decreased by 6% to 15,435 BOEPD compared with the first half of 2011. Production during the first half of 2012 was impacted by an increase in oil inventory in the OTA pipeline as a result of the change in the sales point in Colombia and pipeline disruptions.

- Revenue and other income decreased by 29% to $115.2 million in the second quarter of 2012 compared with $162.1 million in the second quarter of 2011 due to lower production and realized oil prices. The average price realized in the second quarter of 2012 was $89.10 per BOE, a decrease of 9% compared with $97.93 per BOE in the second quarter of 2011. The price was impacted by the settlement of a third party royalty dispute in Colombia which reduced the average realized price by $8.48 per BOE in the second quarter of 2012 and $3.88 per BOE in the first half of 2012.

For the first half of 2012, the average price realized per BOE was consistent with the comparative period in 2011 at $96.04. The third party royalty settlement related to production from July 2009 to May 2012, represented less than 1% of the reported revenue for the periods under dispute, and is not expected to have a materially different effect on future revenue.

- Net income was $13.1 million in the second quarter of 2012, representing basic and diluted net income per share of $0.05. This compares with net income of $31.6 million, or $0.11 per share basic and diluted in the second quarter of 2011. In the second quarter of 2012, lower oil and natural gas sales due to reduced production resulting from pipeline restrictions and lower average realized oil prices, were partially offset by lower DD&A and income tax expense, and foreign exchange losses. Net income decreased by 72% to $12.8 million or $0.05 per share basic and diluted for the first half of 2012 compared with $45.3 million or $0.17 per share basic and $0.16 per share diluted recorded in the comparable period of 2011. In the first half of 2012, lower oil and natural gas sales due to reduced production, increased operating and G&A expenses, increased foreign exchange losses and the absence of the comparative period gain on acquisition were partially offset by lower impairment charges and the absence of the Colombian equity tax expense. Net income in the comparable period in 2011 included a gain on the acquisition of Petrolifera Petroleum Limited ("Petrolifera") of $21.7 million.

- Funds flow from operations decreased by 58% to $37.6 million in the second quarter of 2012 from $88.6 million in the comparable quarter of 2011. The decrease was primarily due to lower oil and natural gas sales due to reduced production and lower realized oil prices, increased operating expenses and realized foreign exchange losses, partially offset by lower income tax expense. For the first half of 2012, funds flow from operations decreased by 25% from $155.1 million to $116.6 million primarily due to lower oil and gas sales, increased operating and G&A expenses and realized foreign exchange losses.

- Cash and cash equivalents were $128.5 million at June 30, 2012, compared with $351.7 million at December 31, 2011. The change in cash and cash equivalents during the first half of 2012 was primarily the result of funds flow from operations of $116.6 million and proceeds from issuance of common shares of $3.7 million being more than offset by an increase in assets and liabilities from operating activities of $141.9 million, capital expenditures of $178.6 million and a $23.0 million increase in restricted cash.

- Working capital (including cash and cash equivalents) was $160.6 million at June 30, 2012, a $52.5 million decrease from December 31, 2011. The decrease was primarily a result of a $223.2 million decrease in cash and cash equivalents, partially offset by a $25.6 million increase in accounts receivable due to the timing of collection of receivables, a $19.9 million increase in inventory due to the new transportation agreement in Colombia, an $82.4 million decrease in taxes payable due to the payment of 2011 income taxes in Colombia, and a $42.8 million decrease in accounts payable, accrued liabilities and other.

- Property, plant and equipment at June 30, 2012 was $1.1 billion, an increase of $55.3 million from December 31, 2011, as a result of $154.2 million of capital expenditures (excluding changes in non-cash working capital), partially offset by $98.9 million of depletion, depreciation and impairment expenses.

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.

In connection with curtailed production and lower commodity prices experienced this year, our capital program for 2012 has been revised to $396 million from $444 million. We believe that our current operations and revised 2012 capital expenditure program can be funded from cash flow from existing operations and cash on hand, with possible periodic draws from our credit facility. Should our operating cash flow decline further 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 further capital expenditure program reductions, periodic draws from our revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. The continuing uncertainty regarding the Middle East and continued economic instability in the United States and Europe is having an impact on world markets, and we are unable to determine the impact, if any, these events may have on oil prices and demand.

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 our common shares. Our ability to utilize our common shares to raise capital may be negatively affected by declines in the price of our common shares. 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 and will expose us to interest rate risk. Depending on the currency used to borrow money, we may also be exposed to further foreign exchange risk. Our ability to borrow money and the interest rate we pay for any money we borrow will be affected by market conditions, and we cannot predict what price we may pay for any borrowed money.

Business Combination

On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru. For further details reference should be made to Note 3 of the interim unaudited condensed consolidated financial statements.

The acquisition was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera's assets acquired and liabilities assumed were recorded at their fair values as at the acquisition date and the results of Petrolifera were consolidated with those of Gran Tierra from that date.

As indicated in the allocation of the consideration transferred, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, we reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, we recognized a gain on acquisition of $21.7 million in the interim unaudited condensed consolidated statement of operations. The gain reflects the impact on Petrolifera's pre-acquisition market value resulting from their lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

Consolidated Results of Operations

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$114,542	$161,664	(29)	$269,790	$283,960	(5)
Interest income	608	456	33	1,311	679	93
	115,150	162,120	(29)	271,101	284,639	(5)
Operating expenses	27,333	23,160	18	51,820	39,556	31
DD&A expenses	32,571	46,965	(31)	92,938	110,322	(16)
G&A expenses	17,599	16,410	7	33,498	30,048	11
Equity tax	—	221	(100)	—	8,271	(100)
Financial instruments gain	—	(1,292)	(100)	—	(1,522)	(100)
Loss (gain) on acquisition	—	2,601	(100)	—	(21,699)	(100)
Foreign exchange loss	4,807	14,495	(67)	29,182	19,694	48
	82,310	102,560	(20)	207,438	184,670	12
Income before income taxes	32,840	59,560	(45)	63,663	99,969	(36)
Income tax expense	(19,736)	(27,993)	(29)	(50,872)	(54,689)	(7)
Net income	$13,104	$31,567	(58)	$12,791	$45,280	(72)
Production						
Oil and NGL's, bbl	1,223,289	1,594,735	(23)	2,684,693	2,888,188	(7)
Natural gas, Mcf	373,710	336,837	11	746,657	431,154	73
Total production, BOE (1)	1,285,574	1,650,875	(22)	2,809,136	2,960,047	(5)
Average Prices						
Oil and NGL's per bbl	$92.48	$100.68	(8)	$99.49	$97.82	2
Natural gas per Mcf	$3.78	$3.32	14	$3.60	$3.31	9
Consolidated Results of Operations per BOE						
Oil and natural gas sales	$89.10	$97.93	(9)	$96.04	$95.93	—
Interest income	0.47	0.28	68	0.47	0.23	104
	89.57	98.21	(9)	96.51	96.16	—
Operating expenses	21.26	14.03	52	18.45	13.36	38
DD&A expenses	25.34	28.45	(11)	33.08	37.27	(11)
G&A expenses	13.69	9.94	38	11.92	10.15	17
Equity tax	—	0.13	(100)	—	2.79	(100)
Financial instruments gain	—	(0.78)	(100)	—	(0.51)	(100)
Loss (gain) on acquisition	—	1.58	(100)	—	(7.33)	(100)
Foreign exchange loss	3.74	8.78	(57)	10.39	6.65	56
	64.03	62.13	3	73.84	62.38	18

Income before income taxes	25.54	36.08	(29)	22.67	33.78	(33)
Income tax expense	(15.35)	(16.96)	(9)	(18.11)	(18.48)	(2)
Net income	$10.19	$19.12	(47)	$4.56	$15.30	(70)

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

Net income was $13.1 million, or $0.05 per share basic and diluted, for the second quarter of 2012 compared with net income of $31.6 million, or $0.11 per share basic and diluted, for the comparable quarter in 2011. In the second quarter of 2012, lower oil and natural gas sales due to reduced production resulting from pipeline restrictions and lower average realized oil prices, were partially offset by lower DD&A and income tax expense, and foreign exchange losses.

For the first half of 2012, net income was $12.8 million, a 72% decrease from the comparable period in 2011. On a per share basis, net income decreased to $0.05 per share basic and diluted from $0.17 per share basic and $0.16 per share diluted in the comparable period in 2011. For the first half of 2012, lower oil and natural gas sales due to reduced production, increased operating and G&A expenses, increased foreign exchange losses and the absence of the comparative period gain on acquisition were partially offset by lower impairment charges and the absence of the Colombian equity tax expense. Net income in the comparable half in 2011 included a gain on the acquisition of Petrolifera of $21.7 million.

Oil and NGL production, NAR and adjusted for inventory changes, for the second quarter of 2012 decreased to 1.2 MMbbl compared with 1.6 MMbbl for the comparable quarter in 2011 primarily due to 59 days of oil delivery restrictions resulting from disruptions in the OTA pipeline in Colombia partially offset by increased production from new producing wells in Colombia. We continued production at a reduced rate while the OTA pipeline was down, selling a portion of our oil through trucking and storing excess oil. The disruptions resulted in a reduction in oil production, compared with our production capacity, of approximately 4,100 BOPD NAR, before inventory adjustments, for the second quarter of 2012. The reduced production of 4,100 BOPD NAR combined with the increase of inventory of approximately 2,000 BOPD NAR resulted in a negative effect on NAR production, net of inventory, of 6,100 BOPD NAR in the quarter.

We are working with the authorities, outside parties and Ecopetrol to look at multiple transportation and storage options to help mitigate the risk of pipeline disruptions. These include more continuous use of the Oleoducto San Miguel pipeline (Orito to Ecuador), additional storage at Orito in combination with higher capacity utilization of the OTA pipeline when it is operational, and higher volumes of trucking to other delivery points on a continuous basis.

Oil and NGL production, NAR and adjusted for inventory changes, for the first half of 2012 decreased to 2.7 MMbbl compared with 2.9 MMbbl for the comparable period in 2011 due to pipeline disruptions and the effect of a change in the sales point in Colombia. As a result of entering into new oil sales and transportation agreements with Ecopetrol as of February 1, 2012, which changed the sales point of produced oil from Orito station to the Port of Tumaco, our reported oil inventory increased representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. Production during the first half of 2012 reflects approximately 85 days of oil delivery restrictions in Colombia. The reduced production of approximately 2,500 BOPD NAR combined with the increase of inventory of approximately 1,700 BOPD NAR resulted in a negative effect on NAR production, net of inventory, of 4,200 BOPD in the first half of 2012.

Average realized oil prices in the second quarter of 2012 decreased by 8% to $92.48 per bbl from $100.68 per bbl in the second quarter of 2011 and increased by 2% to $99.49 per bbl from $97.82 per bbl for the first half of 2012. Average West Texas Intermediate ("WTI") oil prices for the three and six months ended June 30, 2012 were $93.48 and $98.19 per bbl, respectively, compared with $102.55 and $98.25 per bbl in the comparable periods in 2011. We received a premium to WTI in Colombia during the first half of 2012. Average Brent oil prices for the three and six months ended June 30, 2012, were $108.07 and $113.31 per bbl.

During the second quarter of 2012, the recognition of additional royalties resulting from an arbitrator's decision on a dispute with a third party relating to the calculation of the third party's net profits interest on 50% of production from the Chaza Block in Colombia resulted in a $10.9 million revenue reduction. This amount related to July 2009 to May 2012 production. The recognition of this royalty resulted in an $8.48 per BOE reduction in the average realized price in the second quarter of 2012 and $3.88 per BOE in the first half of 2012. The arbitrator's decision will increase future net profit interests payable to this third party. The royalty settlement represented less than 1% of the reported revenue for the periods under dispute and it is not expected to have a materially different effect on future revenue.

Reduced production and lower average realized oil prices resulted in a 29% decrease in revenue and other income to $115.2 million for the second quarter of 2012 compared with $162.1 million in the comparable quarter in 2011. Reduced production resulted in a 5% decrease in revenue and other income to $271.1 million for the first half of 2012 compared with the comparative 2011 period.

Operating expenses for the second quarter of 2012 amounted to $27.3 million, or $21.26 per BOE, compared with $23.2 million, or $14.03 per BOE, in the comparable quarter in 2011. The increase in operating expenses was due to an increase of $2.1 million in Colombia, $1.5 million in Argentina and $0.5 million in Brazil.

Operating expenses for the first half of 2012 increased to $51.8 million or $18.45 per BOE, from $39.6 million or $13.36 per BOE, in the comparable period of 2011. The increase in operating expenses for the first half of 2012 was due to an increase of $5.9 million in Colombia, $5.3 million in Argentina and $1.1 million in Brazil.

DD&A expenses for the second quarter of 2012 were $32.6 million compared with $47.0 million for the comparable quarter in 2011, primarily due to reduced production. On a per BOE basis, DD&A expenses in the second quarter of 2012 were $25.34 compared with $28.45 in the comparable period in 2011, representing an 11% decrease. The decrease resulted from increased reserves, lower production volumes and lower impairment charges which more than offset increased future development costs in the depletable base.

For the first half of 2012, DD&A expenses decreased to $92.9 million from $110.3 million in the comparable period in 2011. DD&A expenses for the first half of 2012 included a $20.2 million ceiling test impairment in our Brazil cost center. The impairment loss related to seismic and drilling costs on Block BM-CAL-10. The farmout 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. DD&A expenses for the comparable period in 2011 included a $33.4 million ceiling test impairment in our Peru cost center relating to seismic and drilling costs from a dry well. On a per BOE basis, the depletion rate declined by 11% to $33.08 from $37.27 in the first half of 2011. The reduction was mainly due to lower impairment charges which were $7.53 per BOE in the first half of 2012 compared with $11.28 per BOE recorded in the comparable period in 2011.

G&A expenses of $17.6 million for the second quarter of 2012 increased by 7% from $16.4 million in the comparable quarter in 2011, primarily due to increased employee related costs reflecting expanded operations, partially offset by the absence of interest expense of $0.8 million on the Petrolifera debt, which was repaid in August 2011. G&A expenses per BOE were 38% higher than in the second quarter in 2012 at $13.69 per BOE due to the same factors and reduced production.

For the first half of 2012, G&A expenses of $33.5 million increased by 11% from $30.0 million in the comparable period in 2011. G&A expenses in the first half of 2011 included $1.2 million of expenses associated with the acquisition of Petrolifera. G&A expenses per BOE were 17% higher than in the first half of 2012, at $11.92 per BOE compared with $10.15 per BOE.

Equity tax in the first half of 2011 represented a Colombian tax of 6% which was calculated based on our Colombian segment's balance sheet equity 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.

Gain on acquisition of $21.7 million in the first half of 2011 related to the Petrolifera acquisition. The gain on acquisition was reduced by $2.6 million during the second quarter of 2011 as a result of further assessment of Petrolifera's tax position, subsequent to the initial allocation of the consideration reported in the first quarter of 2011.

The foreign exchange loss was $4.8 million in the second quarter of 2012 and included a realized foreign exchange loss of $10.0 million. The realized foreign exchange loss primarily arose upon payment of the 2011 Colombian income tax liability during the quarter. In the second quarter of 2011, we recorded a foreign exchange loss of $14.5 million, which included a realized foreign exchange loss of $2.9 million and an unrealized non-cash foreign exchange loss of $11.6 million. Unrealized non-cash foreign exchange losses primarily represent foreign exchange losses resulting from the translation of current and deferred tax liabilities in Colombia. The Colombian Peso strengthened by 0.4% and 5.3% against the U.S. dollar in the second quarters of 2012 and 2011, respectively.

For the first half of 2012 and 2011, the foreign exchange loss was $29.2 million and $19.7 million, respectively, of which $16.2 million and $16.1 million was an unrealized non-cash foreign exchange loss. The Colombian Peso strengthened by 8.1% and 7.0% against the U.S. dollar in the first half of 2012 and 2011, 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 results in the recognition of unrealized exchange losses or gains.

Income tax expense for the second quarter of 2012 was $19.7 million compared with $28.0 million recorded in the comparable quarter in 2011. Income tax expense was $50.9 million for the first half of 2012 compared with $54.7 million recorded in the comparable period in 2011. The decrease was primarily due to lower income. The effective tax rate was 80% in the first half of 2012 compared with 55% in the comparable period in 2011. The change was primarily due to a non-taxable gain on acquisition recorded in 2011, non-deductible royalty payments, the impact of foreign taxes, and an increase in the non-deductible foreign currency translation loss in 2012. The variance from the 35% U.S. statutory rate for the second quarter of 2012 results primarily from non-deductible foreign currency translation losses, non-deductible royalty payments and an increase in valuation allowances taken on losses incurred in Argentina, Peru and Brazil. The variance from the 35% U.S. statutory rate for the second quarter of 2011 was primarily attributable to non-deductible foreign currency translation losses, non-deductible royalty payments, and an increase in valuation allowances taken on losses incurred in the U.S., Canada, Argentina, Peru and Brazil, offset partially by the inclusion of a non-taxable gain on acquisition.

2012 Work Program and Capital Expenditure Program

Our capital expenditures during the second quarter of 2012 were $66.6 million, compared with $101.5 million in the comparable quarter in 2011, bringing total expenditures for the first half of 2012 to $154.2 million. In 2012, capital expenditures included drilling expenditures of $101.9 million, acquisitions of $12.5 million, geological and geophysical (“G&G”) expenditures of $25.8 million, facilities expenditures of $7.1 million and other expenditures of $6.9 million.

As a result of production disruptions and lower commodity prices experienced this quarter, our capital program for 2012 has been revised to $396 million from our previously announced capital budget of $444 million. We had initially increased our 2012 capital budget during the second quarter of 2012 such that this represents an approximately $60 million reduction in the capital budget. Deferred expenditures are in areas which are not expected to impact production capacity or near term high value reserve addition projects. Our 2012 capital program consists of $171 million for Colombia; $111 million for Brazil; $44 million for Argentina; $68 million for Peru; and $2 million associated with corporate activities. Of this, $235 million is for drilling, $48 million is for acquisitions, $48 million is for facilities and pipelines and $65 million is for G&G expenditures. Of the $235 million allocated to drilling, approximately $130 million is for exploration and the balance is for delineation and development drilling.

Our 2012 work program is intended to create both growth and value through strategic acquisitions of working interests, by leveraging existing assets to increase reserves and production levels and through the construction of pipelines and facilities in the areas with proved reserves. We are financing our capital program through cash flows from operations, cash on hand and possible periodic draws from our credit facility, while retaining financial flexibility with a strong cash position, so that we can be positioned to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds will be expended as set forth in our 2012 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Segmented Results – Colombia

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$92,018	$148,473	(38)	$230,651	$265,777	(13)
Interest income	223	158	41	427	245	74
	92,241	148,631	(38)	231,078	266,022	(13)
Operating expenses	17,721	15,558	14	34,195	28,343	21
DD&A expenses	23,084	39,609	(42)	55,370	69,645	(20)
G&A expenses	6,976	5,426	29	13,575	8,739	55
Equity tax	—	221	(100)	—	8,271	(100)
Foreign exchange loss	1,979	14,088	(86)	25,337	19,409	31
	49,760	74,902	(34)	128,477	134,407	(4)
Income before income taxes	$42,481	$73,729	(42)	$102,601	$131,615	(22)
Production						
Oil and NGL's, bbl	928,258	1,380,210	(33)	2,177,839	2,583,825	(16)
Natural gas, Mcf	58,686	60,315	(3)	68,160	115,572	(41)
Total production, BOE (1)	938,039	1,390,263	(33)	2,189,199	2,603,087	(16)
Average Prices						
Oil and NGL's per bbl	$98.96	$107.39	(8)	$105.82	$102.68	3
Natural gas per Mcf	$2.62	$4.25	(38)	$2.73	$4.15	(34)
Segmented Results of Operations per BOE						
Oil and natural gas sales	$98.10	$106.79	(8)	$105.36	$102.10	3
Interest income	0.24	0.11	118	0.20	0.09	122
	98.34	106.90	(8)	105.56	102.19	3
Operating expenses	18.89	11.19	69	15.62	10.89	43
DD&A expenses	24.61	28.49	(14)	25.29	26.75	(5)
G&A expenses	7.44	3.90	91	6.20	3.36	85
Equity tax	—	0.16	(100)	—	3.18	(100)
Foreign exchange loss	2.11	10.13	(79)	11.57	7.46	55
	53.05	53.87	(2)	58.68	51.64	14
Income before income taxes	$45.29	$53.03	(15)	$46.88	$50.55	(7)

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

For the three and six months ended June 30, 2012, income before income taxes from Colombia was $42.5 million and $102.6 million, respectively, compared with $73.7 million and $131.6 million in the comparable periods in 2011. The decreases were due to lower revenues due to pipeline disruptions, increased royalty expenses and increases in operating and G&A expenses, partially offset by reduced DD&A and the absence of equity tax. Foreign exchange losses decreased for the three months ended June 30, 2012, but increased for the six months ended June 30, 2012. Net income in the comparable half of 2011 included equity tax of $8.3 million.

For the second quarter of 2012, production of oil and NGLs, NAR and adjusted for inventory changes, decreased by 33% to 0.9 MMbbl from 1.4 MMbbl in the comparable quarter in 2011. Increased production from new producing wells was offset by the impact of 59 days of oil delivery restrictions resulting from disruptions in the OTA pipeline in Colombia. Increases in production resulted from the development of the Moqueta field with six producing wells and production in the Garibay Block from the Jilguero-1 and -2 and Melero-1 wells. We continued production at a reduced rate while the OTA pipeline was down, selling a portion of our oil through trucking and storing excess oil. The disruptions resulted in a reduction in oil production compared with our production capacity of approximately 4,100 BOPD NAR, before and inventory adjustments, for the second quarter of 2012. The reduced production of 4,100 NAR BOPD combined with the increase of inventory of approximately 2,000 NAR BOPD resulted in a negative effect on NAR production, net of inventory of 6,100 BOPD in the quarter.

Oil and NGL production, NAR and adjusted for inventory changes, for the first half of 2012 decreased to 2.2 MMbbl compared with 2.6 MMbbl for the comparable period in 2011 due to pipeline disruptions and the effect of a change in the sales point. As a result of entering into new oil sales and transportation agreements with Ecopetrol as of February 1, 2012, which changed the sales point of produced oil from Orito station to the Port of Tumaco, our reported oil inventory increased representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. Production during the first half of 2012 reflects approximately 85 days of oil delivery restrictions in Colombia. The reduced oil production of approximately 2,500 BOPD NAR combined with the increase of inventory of approximately 1,700 NAR BOPD resulted in a negative effect on NAR production, net of inventory, of 4,200 BOPD in the first half of 2012.

Revenue and other income for the three and six months ended June 30, 2012 decreased by 38% to $92.2 million and 13% to $231.1 million, respectively, from the comparable periods in 2011.

The average realized price per bbl for oil in the three months ended June 30, 2012 decreased by 8% to $98.96. For the first half of 2012, the average realized price per bbl for oil increased by 3% to $105.82 from the comparable period in 2011. During the second quarter of 2012, the recognition of royalties resulting from an arbitrator's decision on a royalty dispute reduced the average realized price by $11.62 per BOE in the second quarter of 2012 and $4.98 per BOE in the first half of 2012.

Operating expenses increased by 14% to $17.7 million and 21% to $34.2 million for the three and six months ended June 30, 2012, respectively, from the comparable periods in 2011. On a per BOE basis, operating expenses increased by 69% to $18.89 and 43% to $15.62 for the three and six months ended June 30, 2012, respectively. Under the new sales agreements with Ecopetrol, effective February 1, 2012, the sales point for the majority of our oil moved from Orito to the Port of Tumaco. OTA transportation costs were previously factored into the price we received for oil, but, due to the changes in sales point, are now invoiced separately and included in operating costs. This resulted in an increase in OTA oil transportation costs of $3.63 per bbl during the second quarter of 2012 and is expected to increase transportation costs by $3.77 per bbl for the third quarter of 2012 but should be offset by an equivalent increase in the realized price. Operating expenses per BOE were higher due to OTA pipeline oil transportation costs now recorded as operating costs, increased trucking due to the pipeline disruptions, reduced production and a higher percentage of production being from the Moqueta, Jilguero and Melero fields which have higher per BOE operating costs. Workover costs were consistent with the comparable quarter in 2011.

DD&A expenses decreased by 42% to $23.1 million and 20% to $55.4 million for the three and six months ended June 30, 2012, respectively, from the comparable periods in 2011. The decrease in both periods resulted from lower production and depletion rates. On a per BOE basis, DD&A expenses decreased by 14% to $24.61 and 5% to $25.29 for the three and six months ended June 30, 2012, respectively. Increased costs in our depletable pools were more than offset by increased reserves.

G&A expenses for the second quarter of 2012 increased to $7.0 million ($7.44 per BOE) from $5.4 million ($3.90 per BOE) in the comparable quarter in 2011. The increase was mainly due to increased salaries resulting from an increased headcount due to expanded operations and increased bank charges. The increase per BOE was due to reduced production. For the first half of 2012, G&A expenses increased by 55% to $13.6 million ($6.20 per BOE) due to increased salaries, consulting fees and bank charges.

Equity tax in the first half of 2011 represented a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011.

The results for the second quarter of 2012 included a foreign exchange loss of $2.0 million, which included a realized foreign exchange loss of $7.1 million. The realized foreign exchange loss primarily arose upon payment of the 2011 Colombian income tax liability during the quarter. The settlement of this liability crystallized the previously unrealized losses associated with the taxes payable and the reduction of the unrealized foreign exchange loss balance appears as an unrealized foreign exchange gain in the quarter. For the comparable quarter in 2011, the foreign exchange loss was $14.1 million, of which $11.6 million was unrealized. Unrealized non-cash foreign exchange losses primarily represent foreign exchange losses resulting from the translation of current and deferred tax liabilities in Colombia. The Colombian Peso strengthened by 0.4% and 5.3% against the U.S. dollar in the second quarter of 2012 and 2011, respectively, resulting in the unrealized foreign exchange loss. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

For the first half of 2012 and 2011, the foreign exchange loss was $25.3 million and $19.4 million, respectively, of which $16.2 million and $16.0 million was an unrealized non-cash foreign exchange loss. The Colombian Peso strengthened by 8.1% and 7.0% against the U.S. dollar in the first half of 2012 and 2011, respectively.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the second quarter of 2012 were $42.3 million bringing total expenditures for the first half of 2012 to $62.6 million. The following table provides a breakdown of capital expenditures in 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of U.S. Dollars)	2012	2011	2012	2011
Drilling and completions	$29.9	$26.4	$40.4	$56.8
Facilities and equipment	3.3	9.9	10.6	15.0
G&G	4.5	4.3	6.2	5.1
Other	4.6	13.6	5.4	19.6
	$42.3	$54.2	$62.6	$96.5

On June 5, 2012, we received regulatory approval of a farm-in agreement on the Llanos-22 Block (45% working interest ("WI"), non-operated). This approval triggered a payment of $21.1 million for drilling costs related to the Ramiriqui-1 oil exploration well.

During the second quarter of 2012, we drilled 2 exploration wells and 1 development well in Colombia:

- Drilling commenced for the La Vega Este-1 oil exploration well on the Azar Block (40 % WI, operated).

- The Bordon-1 oil exploration well was drilled on the Garibay Block (50 % WI, non-operated). This well reached total depth ("TD") of 9,680 feet during June 2012, but was plugged and abandoned.

- The Costayaco-16 development well was successfully drilled and is intended to be a producing well.

Pre-drilling activities for the Moqueta-7 development well continued during the second quarter of 2012.

Additionally, 3D seismic was acquired and facilities work continued on the Costayaco and Moqueta fields.

Outlook - Colombia

The 2012 capital program in Colombia is $171 million with $106 million allocated to drilling, $27 million to facilities and pipelines and $38 million for G&G expenditures.

Our planned work program for the remainder of 2012 in Colombia includes drilling three development wells on the Costayaco and Moqueta fields, an oil exploration well on the Turpial Block (50 % WI, operated) and a natural gas development well on the Sierra Nevada Block (100 % WI, operated). Additionally, G&G expenditures are planned for the Putumayo-1 Block and facilities work for additional storage at Orito.

Segmented Results – Argentina

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$21,482	$12,857	67	$36,851	$17,849	106
Interest income	39	28	39	86	28	207
	21,521	12,885	67	36,937	17,877	107
Operating expenses	8,947	7,428	20	16,293	10,975	48
DD&A expenses	7,990	5,505	45	13,915	6,652	109
G&A expenses	2,759	2,779	(1)	5,010	3,697	36
Foreign exchange loss	557	272	105	928	82	1,032
	20,253	15,984	27	36,146	21,406	69
Income (loss) before income taxes	$1,268	$(3,099)	(141)	$791	$(3,529)	(122)
Production						
Oil and NGL's, bbl	283,538	210,512	35	482,838	300,350	61
Natural gas, Mcf	315,024	276,522	14	678,497	315,582	115
Total production, BOE (1)	336,042	256,599	31	595,921	352,947	69
Average Prices						
Oil and NGL's per bbl	$71.32	$57.01	25	$71.13	$56.27	26
Natural gas per Mcf	$4.00	$3.11	29	$3.69	$3.00	23
Segmented Results of Operations per BOE						
Oil and natural gas sales	$63.93	$50.11	28	$61.84	$50.57	22
Interest income	0.12	0.11	9	0.14	0.08	75
	64.05	50.22	28	61.98	50.65	22
Operating expenses	26.62	28.95	(8)	27.34	31.10	(12)
DD&A expenses	23.78	21.45	11	23.35	18.85	24
G&A expenses	8.21	10.83	(24)	8.41	10.47	(20)
Foreign exchange loss	1.66	1.06	57	1.56	0.23	578
	60.27	62.29	(3)	60.66	60.65	—
Income (loss) before income taxes	$3.78	$(12.07)	(131)	$1.32	$(10.00)	(113)

(1)

Production represents production volumes NAR adjusted for inventory changes. 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.

For the three and six months ended June 30, 2012, income before income taxes in Argentina was $1.3 million and $0.8 million, respectively, compared with loss before income taxes of $3.1 million and $3.5 million in the comparable periods in 2011. In the second quarter and first half of 2012, increased oil and natural gas sales more than offset increased operating and DD&A expenses.

Oil and NGL production, NAR and adjusted for inventory changes, increased 35% to 0.3 MMbbl for the three months ended June 30, 2012 and increased 61% to 0.5 MMbbl for the first half of 2012 compared with the comparable periods in 2011. The increase in the second quarter of 2012 was due to production from the new well, Proa-2, in the Surubi block, partially offset by reduced production in the Puesto Morales Block due to landowner conflicts, now resolved.

The acquisition of Petrolifera on March 18, 2011, added seven blocks in the Neuquen Basin, including production from four blocks, to the Argentina segment. Production in the first half of 2012 included a full six months of Petrolifera production of 0.4 MMbbl, NAR and adjusted for inventory changes, compared with 104 days of post-acquisition Petrolifera production of 0.2 MMbbl in the first half of 2011.

Natural gas production NAR amounted to 0.3 Bcf in the second quarter of 2012 bringing natural gas production year to date to 0.7 Bcf.

Total production of oil and gas from the Argentina segment increased by 31% to 0.3 MMBOE in the second quarter of 2012 and by 69% to 0.6 MMBOE for the first half of 2012.

Revenue and other income increased by 67% to $21.5 million in the second quarter of 2012 and by 107% to $36.9 million for the first half of 2012 due to higher production and increased prices.

Average oil prices increased by 25% in the second quarter of 2012 and 26% in the first half of 2012 compared with the comparable periods in 2011. Due to the Argentine regulatory regime, the average oil price we received for production from our blocks during the second quarter of 2012 was $71.32 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. We have been able to negotiate higher oil prices with refineries as a result of the Argentine government’s decision to allow an increase in domestic petroleum product prices.

Operating expenses increased by 20% to $8.9 million and 48% to $16.3 million for the three and six months ended June 30, 2012, respectively, from the comparable periods in 2011. The increase was due to higher production volumes partially offset by a reduction in the per BOE cost. On a per BOE basis, operating expenses decreased by 8% to $26.62 and 12% to $27.34 for the three and six months ended June 30, 2012, respectively. The reduction in operating costs on a per BOE basis was due to increased production from blocks with lower per BOE operating costs, such as the Surubi Block.

DD&A expenses increased by 45% to $8.0 million and 109% to $13.9 million for the three and six months ended June 30, 2012, respectively, from the comparable periods in 2011. The increase was due to higher production volumes and an increase in the per BOE depletion rate. On a per BOE basis, DD&A expenses increased by 11% to $23.78 and 24% to $23.35 for the three and six months ended June 30, 2012, respectively, due to a reduction of reserves.

G&A expenses were $2.8 million ($8.21 per BOE) and $5.0 million ($8.41 per BOE) in the three and six months ended June 30, 2012, respectively, compared with $2.8 million ($10.83 per BOE) and $3.7 million ($10.47 per BOE) in the comparable periods. G&A expenses in the first half of 2011 included $0.8 million of interest expense on debt acquired on the Petrolifera acquisition which was repaid when the Argentine requirements allowed it to be repaid. For the first half of 2012, increased salaries and benefits due to an increased headcount as a result of expanded operations were partially offset by the absence of loan interest.

Capital Program - Argentina

Capital expenditures in our Argentine segment during the second quarter of 2012 were $2.7 million bringing total expenditures for the first half of 2012 to $16.8 million. Second quarter 2012 capital expenditures included drilling expenditures of $1.5 million, G&G expenses of $0.7 million, facilities expenses of $0.3 million and other expenditures of $0.2 million.

During the second quarter of 2012, we drilled two exploration wells and completed one development well in Argentina:

- The R.N. x-1008 oil exploration well on the Rinconada Norte Block (35% WI, non-operated) was drilled to a TD of 1,050 feet and completed as a producing well.

- The Los Incas-1 exploration well on the Puesto Guevera Block (100% WI, operated) was drilled, but was plugged and abandoned.

- On the Surubi Block (85% WI, operated), the Proa-2 oil development well reached TD of 12,894 feet in April 2012 and is currently producing.

Additionally, we successfully completed 2 workovers on the Puesto Morales Block (100% WI, operated).

Outlook – Argentina

The 2012 capital program in Argentina is $44 million with $32 million allocated to drilling, $6 million to facilities and pipelines, and $6 million to G&G expenditures.

Our planned work program for the remainder of 2012 in Argentina includes drilling eight development wells on the Puesto Morales Block, one gross exploration well and two gross development wells on the Rinconada Norte Block, workovers on existing wells and three well conversions. We also plan to acquire G&G on the Puesto Morales, Rinconada Norte and Valle Morado Blocks, perform facilities work on the Puesto Morales, El Chivil, Palmar Largo and Valle Morado Blocks and undertake an enhanced oil recovery pilot project on the Puesto Morales Block.

Segmented Results – Peru

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
(Thousands of U.S. Dollars)						
Interest income	$—	$134	(100)	$15	$134	(89)
Operating expenses	80	108	(26)	161	$172	(6)
DD&A expenses	991	1,530	(35)	1,106	33,463	(97)
G&A expenses	1,466	1,000	47	2,082	1,565	33
Foreign exchange loss (gain)	36	(133)	(127)	(34)	(70)	(51)
	2,573	2,505	3	3,315	35,130	(91)
Loss before income taxes	$(2,573)	$(2,371)	9	$(3,300)	$(34,996)	(91)

DD&A expenses in the first half of 2011 of $33.5 million included a $33.4 million ceiling test impairment in our Peru cost center relating to seismic and drilling costs related to a dry hole. DD&A expenses in the second quarter of 2012 and 2011 and the first half of 2012 included $0.9 million, $1.5 million and $0.9 million, respectively, of impairment charges related to blocks which were relinquished in 2011.

G&A expenses were $1.5 million and $1.0 million in the second quarter of 2012 and 2011 and $2.1 million and $1.6 million in the first half of 2012 and 2011, respectively. The increases were due to higher salaries and stock-based compensation expense resulting from expanded operations.

Capital Program – Peru

Capital expenditures in our Peruvian segment during the second quarter of 2012 were $16.0 million, bringing total expenditures for the first half of 2012 to $32.7 million

Second quarter of 2012 capital expenditures included drilling expenditures of $4.4 million, and acquisitions of $5.4 million, G&G expenses of $6.0 million and other expenditures of $0.2 million.

During the second quarter of 2012, we entered into an agreement to acquire the remaining 40% working interest in Block 95 in Peru and continued civil construction of a drilling platform and dock facility on this block. Additionally, we acquired 2D seismic on Blocks 123 and 129 (20% WI, non-operated).

Outlook - Peru

The 2012 capital program in Peru is $68 million with $34 million allocated to drilling, $12 million to acquisitions, $1 million to facilities and pipelines and $21 million for G&G expenditures.

Our planned work program for the remainder of 2012 in Peru includes pre-drilling activities and the commencement of drilling for one gross exploration well on Block 95, an aeromagnetic and aerogravity survey and EIAs on Block 133 and environmental health and safety programs on all blocks.

Results - Operations in Brazil

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$1,042	$334	212	$2,288	$334	585
Interest income	272	—	—	567	11	5,055
	1,314	334	293	2,855	345	728
Operating expenses	585	66	786	1,171	66	1,674
DD&A expenses	266	156	71	22,074	252	8,660
G&A expenses	456	1,396	(67)	1,137	2,665	(57)
Foreign exchange loss	1,235	92	1,242	1,770	106	1,570
	2,542	1,710	49	26,152	3,089	747
Loss before income taxes	$(1,228)	$(1,376)	(11)	$(23,297)	$(2,744)	749
Production (1)						
Oil and NGL's, bbl	11,493	4,013	186	24,016	4,013	498
Average Prices						
Oil and NGL's per bbl	$90.66	$83.23	9	$95.27	$83.23	14
Segmented Results of Operations per BOE						
Oil and natural gas sales	$90.66	$83.23	9	$95.27	$83.23	14
Interest income	23.67	—	—	23.61	2.74	762
	114.33	83.23	37	118.88	85.97	38
Operating expenses	50.90	16.45	209	48.76	16.45	196
DD&A expenses	23.14	38.87	(40)	919.14	62.80	1,364
G&A expenses	39.68	347.87	(89)	47.34	664.09	(93)
Foreign exchange loss	107.46	22.93	369	73.70	26.41	179
	221.18	426.12	(48)	1,088.94	769.75	41
Loss before income taxes	$(106.85)	$(342.89)	(69)	$(970.06)	$(683.78)	42

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil.

We began recording revenue from production in Brazil from Block 155 in the onshore Recôncavo Basin on June 15, 2011, the date regulatory approval was received for the purchase of our 70% participating interest in that block.

For the three months ended June 30, 2012, loss before taxes from Brazil was $1.2 million compared with loss before taxes of $1.4 million in the comparable period in 2011. For the six months ended June 30, 2012, loss before income taxes was $23.3 million compared with $2.7 million in the comparable period in 2011.

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Oil and natural gas sales and operating expenses in 2012 represented sales and operating expenses from Block 155. Average Brent oil prices for the three and six months ended June 30, 2012 were $108.07 and $113.31 per bbl. The price we received during the quarter was at a discount to Brent due to a refining discount.

DD&A expenses in first half of 2012 included a ceiling test impairment loss of $20.2 million in our Brazil cost center. The impairment loss related to seismic and drilling costs on Block BM-CAL-10.

G&A expenses were $0.5 million and $1.4 million in the second quarter of 2012 and 2011 and $1.1 million and $2.7 million in the first half of 2012 and 2011, respectively. We began recognizing production in Brazil in June 2011 upon receipt of regulatory approval. This resulted in a significant increase in the costs that were directly attributable to operations and exploration and development and a reduction in G&A expenses compared with the same period in 2011.

The foreign exchange loss resulted from the translation of foreign currency denominated transactions to U.S. dollars.

Capital Program – Brazil

Capital expenditures in Brazil during the second quarter of 2012 were $5.4 million bringing total expenditures for the first half of 2012 to $41.7 million. Second quarter 2012 capital expenditures included $5.3 million of drilling expenditures and $0.1 million of other expenditures.

During the second quarter of 2012, we completed two development wells, 3-GTE-03D-BA and 3-GTE-4DPA-BA, on Block 155 (70% WI and operator, remaining 30% WI subject to approval) in Brazil. These wells had TD of 7,458 feet and 7,723 feet. Production from these wells will commence once oil sales agreements and gas flaring volume limits have been finalized.

On January 20, 2012, we entered into a purchase and sale agreement to acquire the remaining 30% participating interest in Blocks 129, 142, 155 and 224 in the Recôncavo Basin in Brazil from our partner. Closing of the transaction is subject to regulatory approval.

Outlook – Brazil

The 2012 capital program in Brazil is $111 million with $63 million allocated to drilling, $36 million to acquisitions costs and $12 million to facilities and pipelines expenditures.

Our planned work program for the remainder of 2012 in Brazil includes drilling two oil exploration wells on Blocks 155 and 142 (70% WI and operator, remaining 30% WI subject to approval) and facilities work on Block 155.

Results - Corporate Activities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	% Change	2012	2011	% Change
(Thousands of U.S. Dollars)						
Interest income	$74	$136	(46)	$216	$261	(17)
DD&A expenses	240	165	45	473	310	53
G&A expenses	5,942	5,809	2	11,694	13,382	(13)
Financial instruments gain	—	(1,292)	(100)	—	(1,522)	(100)
Gain on acquisition	—	2,601	(100)	—	(21,699)	(100)
Foreign exchange loss	1,000	176	468	1,181	167	607
	7,182	7,459	(4)	13,348	(9,362)	(243)
Loss (income) before income taxes	$(7,108)	$(7,323)	(3)	$(13,132)	$9,623	(236)

G&A expenses in the second quarter of 2012 of $5.9 million were comparable to the second quarter of 2011. For the first half of 2012, G&A expenses were $11.7 million compared with $13.4 million in the first half of 2011. In the first half of 2012, increases in salaries expenses due to expanded operations, were more than offset by an increase in the amount of costs recovered from business units and the absence of Petrolifera acquisition costs ($1.2 million in the first half of 2011).

Gain on acquisition in the first half of 2011 related to the acquisition of Petrolifera. The gain on acquisition was reduced by $2.6 million during the second quarter of 2011 as a result of further assessment of Petrolifera's tax position subsequent to the initial allocation of the consideration reported in the first quarter of 2011.

Liquidity and Capital Resources

At June 30, 2012, we had cash and cash equivalents of $128.5 million compared with $351.7 million at December 31, 2011.

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 2012, 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 with the highest 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 June 30, 2012, 73% 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. We do not intend to repatriate funds, but if we did we would have to accrue and pay taxes.

Effective July 30, 2010, we established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve based facility has a maximum borrowing base of up to $100 million and is supported by the present value of our Colombian petroleum reserves of two of our subsidiaries with operating branches in Colombia – Gran Tierra Energy Colombia Ltd. and Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 million and, effective August 2, 2012, the committed borrowing base was increased to $50 million. 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. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. On May 17th, 2012, BNP Paribas sold Solana's credit facility to Wells Fargo Bank National Association, as part of the sale of its North American reserve-based lending business. At June 30, 2012 and December 31, 2011, we had not drawn down any amounts under this facility.

As part of the acquisition of Petrolifera, we assumed a reserve backed credit facility with outstanding balance as at the acquisition date of $31.3 million. The outstanding balance was repaid when the Argentine restriction preventing its repayment expired on August 5, 2011. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries.

Cash Flows

During the six months ended June 30, 2012, our cash and cash equivalents decreased by $223.2 million as a result of cash used in operating activities of $25.3 million, cash used in investing activities of $201.6 million, partially offset by cash provided by financing activities of $3.7 million.

Cash used in operating activities in the six months ended June 30, 2012 was affected by decreased production, increased operating expenses and a $141.9 million impact from changes in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $17.7 million due to increased oil and gas sales and the timing of collection of receivables; inventory increased by $13.5 million due to the new transportation agreement in Colombia; accounts payable and accrued liabilities decreased by $28.6 million; and taxes payable decreased by $82.3 million due to tax payments in Colombia. The decrease in accounts payable and accrued liabilities was primarily the result of a reduction in royalties payable due to the timing of royalty payments, a decrease in capital expenditure related liabilities due to lower activity and a reduction in VAT payable.

Cash outflows from investing activities in the second quarter of 2012 included capital expenditures of $178.6 million and an increase in restricted cash of $23.0 million.

Cash provided by financing activities in the second quarter of 2012 related to proceeds from issuance of common shares.

Off-Balance Sheet Arrangements

As at June 30, 2012, we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of June 30, 2012:

	As at June 30, 2012 Payments Due in Period				
	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
(Thousands of U.S. Dollars)					
Oil transportation services	$32,560	$8,710	$7,100	$7,100	$9,650
Drilling and geological and geophysical	39,480	38,374	1,106	—	—
Completions	30,828	24,560	6,268	—	—
Facility construction	31,000	17,049	13,951	—	—
Operating leases	6,882	2,861	3,003	1,018	—
Software and telecommunication	8,093	3,685	4,408	—	—
Consulting	1,058	1,058	—	—	—
Total	$149,901	$96,297	$35,836	$8,118	$9,650

Contractual commitments increased from $146.2 million at December 31, 2011 mainly as a result of increased drilling cost commitments for Block 95 in Peru and the Recôncavo Basin Blocks in Brazil and increased facilities cost commitments for the Puesto Morales Block in Argentina.

At June 30, 2012, we had also provided promissory notes totaling $34.4 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Related Party Transactions

On January 12, 2011, we entered into an agreement to sublease office space to a company of which our President and Chief

Executive Officer serves as an independent director. The term of the sublease runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,300 per month plus approximately $5,500 of operating and other expense.

On August 3, 2010, we entered into a contract related to the Peru drilling program with a company for which one of our directors is a shareholder and director. During the three and six months ended June 30, 2011, $0.2 million and $2.2 million was incurred and capitalized under this contract. During the three and six months ended June 30, 2012, $nil was incurred and capitalized under this contract.

On February 1, 2009, we entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was $8,000 per month plus approximately $4,700 for operating and other expenses.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2011 Annual Report on Form 10-K, filed with the SEC on February 27, 2012, 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 are defined by contract relative to WTI or Brent and adjusted for transportation and 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, unrealized foreign exchange gains and losses result from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, which are mainly 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 $105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

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 government securities of the United States or Canadian federal governments such as Guaranteed Investment

Certificates or Treasury Bills. 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

(a) Evaluation of Disclosure 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 June 30, 2012 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 June 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

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 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 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 million barrels. Discussions with the ANH have not resolved this issue and Gran Tierra has sent notice to the ANH to initiate the dispute resolution process prescribed by the Chaza Contract. As at June 30, 2012, total cumulative production from the Moqueta field was 0.6 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH’s interpretation is successful is $10.3 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.

Gran Tierra is subject to a third party 10% net profits interest on 50% of Gran Tierra's production from the Chaza Block that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There was a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party agreed to resolve this issue through arbitration. The arbitration was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. Gran Tierra received the arbitrator's decision on May 24, 2012. The arbitrator ruled against Gran Tierra and as a result $10.9 million became payable in relation to past production. The arbitrator's decision will also increase future net profit interests payable to this third party, but is not expected to have a material impact on future results.
We have several other lawsuits and claims pending for which we currently cannot determine the ultimate result. We record costs as they are incurred or become probable and determinable. 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.

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, 2011, filed with the Securities and Exchange Commission on February 27, 2012, are set forth below and are unchanged substantively at June 30, 2012, 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 has 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 guerilla 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 size 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 a target by these guerilla groups. In March and April of 2008, June, July, August and October of 2009, June, August, and September of 2010, February 2011 and February, March, April, May, June and July of 2012, sections of the OTA pipeline were sabotaged by guerrillas, which temporarily reduced our deliveries to Ecopetrol during the affected periods. In the first six months of 2012, the OTA pipeline was shutdown for over 70 days and the shutdown has had a material adverse effect on our deliveries to Ecopetrol and our financial performance for 2012 and such disruptions may continue indefinitely.

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 field 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 has 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 the reduced 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 and February to July of 2012 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.

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.

In addition, alternative transportation arrangements do not currently have capacity in order for us to deliver our regular volumes of sales. When disruptions are of a long enough duration, our sales volumes will 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 interrupt production.

*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 Argentine 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 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 in the world. 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 2012 and 2011, Argentina has experienced increased union activity and this may create disruptions in our Argentine operations in the future. During 2012, 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 Argentine 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.

*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 2012 calls for approximately $396 million to fund our exploration and development, which we intend to fund through existing cash and cash flows from operations, with possible 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 private 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 million barrels. 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 million barrels.

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 million barrels. 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 that stipulate formal negotiations between the parties, which if unsuccessful are followed by an arbitration conducted in accordance with Colombian law. 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 June 30, 2012, total cumulative production from the Moqueta field was 0.6 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH’s interpretation is successful is $10.3 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 take has been reduced and capital investment in oilfields has declined, and so they are lobbying to change the situation. We are working with other oil and gas producers in the area, as well as refiners, to lobby the federal government for change. 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 from Repsol S.A. (Respol S.A. holds 56.7% of YPF), and retain 51% control for the Federal Government and distribute 49% of the shares to Argentine provinces. 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 Argentine 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.

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, Argentina, Peru and Calgary, 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.

*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 United States dollars and foreign currencies. 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 production in Argentina is primarily invoiced in United States dollars, but payment is made in Argentine pesos, at the then current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to United States 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 Argentine peso and U.S. dollar has varied between 3.05 pesos to one U.S. dollar to 4.53 pesos to the U.S. dollar, a fluctuation of approximately 43%. 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 Real to one U.S. dollar to 2.45 Real to the U.S. dollar, a variance of 57%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the strengthening of 0.4% in the Colombian Peso against the U.S. dollar in the six months ended June 30, 2012 resulted in a foreign exchange loss.

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.

Exchange controls may prevent us from transferring funds abroad. For example, the Argentine 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 Argentine Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentine subsidiaries to make dividend payments to us and there may be a tax imposed with respect to the expatriation of the proceeds from our foreign subsidiaries. The Brazilian government has similar regulations in place regarding foreign exchange controls.

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.

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.

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 newly elected 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. While we do not have any reserves or any producing wells in Peru at this time, we do hold significant land holdings in Peru and such actions by the newly elected political regime could limit the amount of our future revenue in that country and affect our results of operations.

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 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 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/or 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.

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.

*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. 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.

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. Other drilling projects are being delayed 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 is taking 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 restriction 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.

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, 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 Argentine proved reserves and a decrease in reserve volumes. In the first half of 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 farmout 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.

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.

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.

*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 barrel was $66 in 2006, $72 in 2007, $100 in 2008, $62 in 2009, $79 in 2010, $95 in 2011 and $98 for the six months ending June 30, 2012, demonstrating the inherent volatility in the market. Average Brent oil prices for the three and six months ended June 30, 2012 were $108.07 and $113.31 per bbl. Given the current economic environment and unstable conditions in the Middle East, North Africa, the United States and Europe, the oil price environment is increasingly 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 and 2012 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.

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 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;
- 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 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 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 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 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 our common stock.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On eighteen separate dates beginning on April 1, 2012 and ending on June 30, 2012, we sold an aggregate of 2,693,021 common shares for an aggregate purchase price of $2,800,173. These shares were issued to twenty-four holders of warrants to purchase shares of our common stock upon exercise of the warrants. The shares were issued to these holders in reliance on Section 4(2) under the Securities Act, in that they were issued to the original purchasers of the warrants, who had represented to us in the private placement of the warrants that they were accredited investors as defined in Regulation D under the Securities Act.

Item 6. Exhibits

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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: August 7, 2012	/s/ Dana Coffield By: Dana Coffield Chief Executive Officer and President (Principal Executive Officer)
Date: August 7, 2012	/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 September 22, 2008 (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	Amendment to Employment Agreement dated May 2, 2012 between Gran Tierra Energy Inc. and Martin Eden	Incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2012, (SEC File No. 001-34018).
10.2	Amendment to Employment Agreement dated May 2, 2012 between Gran Tierra Energy Inc. and David Hardy	Incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2012, (SEC File No. 001-34018).

10.3	Executive Employment Agreement dated May 2, 2012 between Gran Tierra Energy Inc. and James Rozon	Incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2012, (SEC File No. 001-34018).
10.4	Resignation, Consent and Appointment Agreement and Amendment Agreement, effective May 17, 2012, assigning the Credit Agreement among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Lenders, to Wells Fargo Bank, National Association	Filed herewith.
10.5	Fifth Amendment to Credit Agreement, dated as of May 18, 2012, among Solana Resources Limited, Gran Tierra Energy Inc. Wells Fargo Bank, National Association, and the Lenders	Filed herewith.
10.6	Amended and Restated 2007 Equity Incentive Plan	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.

* XBRL information is furnished and not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.