GRAN TIERRA ENERGY INC.
Form 10-Q
August 07, 2014

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

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

For the quarterly period ended June 30, 2014

or

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

For the transition period from __________ to __________

Commission file number 001-34018

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer o

Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý

On August 1, 2014, the following number of shares of the registrant's capital stock were outstanding: 275,234,547 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 4,534,127 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 5,712,479 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Six Months Ended June 30, 2014

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q, particularly in Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q, including without limitation statements in the Management’s Discussion and Analysis of Financial Condition and Results of Operations, regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words “believe”, “expect”, “anticipate”, “intend”, “estimate”, “project”, “target”, “goal”, “plan”, “objective”, “should”, or similar expressions or these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part II, Item 1A “Risk Factors” in this Quarterly Report on Form 10-Q. The information included herein is given as of the filing date of this Form 10-Q with the Securities and Exchange Commission (“SEC”) and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
bopd	barrels of oil per day	MMBtu	million British thermal units
BOE	barrels of oil equivalent	NGL	natural gas liquids
MMBOE	million barrels of oil equivalent	NAR	net after royalty
BOEPD	barrels of oil equivalent per day		

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

NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the discussion that follows we discuss our interests in wells and/or acres in gross and net terms. Gross oil and natural gas wells or acres refer to the total number of wells or acres in which we own a working interest. Net oil and natural gas wells or acres are determined by multiplying gross wells or acres by the working interest that we own in such wells or acres. Working interest refers to the interest we own in a property, which entitles us to receive a specified percentage of the proceeds of the sale of oil and natural gas, and also requires us to bear a specified percentage of the cost to explore for, develop and produce that oil and natural gas. A working interest owner that owns a portion of the working interest may participate either as operator, or by voting its percentage interest to approve or disapprove the appointment of an operator, in drilling and other major activities in connection with the development of a property.

We also refer to royalties and farm-in or farm-out transactions. Royalties include payments to governments on the production of oil and gas, either in kind or in cash. Royalties also include overriding royalties paid to third parties. Our reserves, production volumes and sales are reported net after deduction of royalties. As noted above, production volumes are also reported net of inventory adjustments and losses. Farm-in or farm-out transactions refer to transactions in which a portion of a working interest is sold by an owner of an oil and gas property. The transaction is labeled a farm-in by the purchaser of the working interest and a farm-out by the seller of the working interest. Payment in a farm-in or farm-out transaction can be in cash or in kind by committing to perform and/or pay for certain work obligations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PART I - Financial Information

Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
REVENUE AND OTHER INCOME				
Oil and natural gas sales	$147,888	$150,250	$298,993	$336,490
Interest income	638	324	1,388	671
	148,526	150,574	300,381	337,161
EXPENSES				
Operating	25,346	23,970	47,212	56,013
Depletion, depreciation, accretion and impairment	41,937	55,592	86,201	106,054
General and administrative	13,932	9,090	26,795	18,112
Foreign exchange loss (gain)	10,044	(12,622)	5,834	(18,979)
Financial instruments gain (Note 10)	(2,604)	—	(5,013)	—
Other loss (Notes 9 and 10)	—	—	—	4,400
	88,655	76,030	161,029	165,600
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	59,871	74,544	139,352	171,561
Income tax expense (Note 8)	(28,387)	(24,960)	(58,096)	(61,977)
INCOME FROM CONTINUING OPERATIONS	31,484	49,584	81,256	109,584
Loss from discontinued operations, net of income taxes (Note 3)	(22,347)	(1,801)	(26,990)	(3,888)
NET INCOME AND COMPREHENSIVE INCOME	9,137	47,783	54,266	105,696
RETAINED EARNINGS, BEGINNING OF PERIOD	456,090	342,586	410,961	284,673
RETAINED EARNINGS, END OF PERIOD	$465,227	$390,369	$465,227	$390,369
INCOME (LOSS) PER SHARE				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$0.11	$0.18	$0.29	$0.38
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(0.08)	(0.01)	(0.10)	(0.01)
NET INCOME	$0.03	$0.17	$0.19	$0.37
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$0.11	$0.18	$0.28	$0.38
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(0.08)	(0.01)	(0.09)	(0.01)
NET INCOME	$0.03	$0.17	$0.19	$0.37
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	283,773,204	282,822,383	283,505,690	282,482,343
	287,856,959	285,449,708	288,338,698	285,646,763

WEIGHTED AVERAGE SHARES
OUTSTANDING - DILUTED (Note 6)

(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, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$332,359	$428,800
Restricted cash	855	1,478
Accounts receivable	111,182	49,703
Marketable securities (Note 10)	14,251	—
Other financial instruments (Note 10)	12	—
Inventory (Note 5)	25,410	13,725
Taxes receivable	14,998	9,980
Prepaids	4,362	6,450
Deferred tax assets (Note 8)	1,364	2,256
Total Current Assets	504,793	512,392
Oil and Gas Properties (using the full cost method of accounting)		
Proved	760,483	794,069
Unproved	479,075	456,001
Total Oil and Gas Properties	1,239,558	1,250,070
Other capital assets	9,118	10,102
Total Property, Plant and Equipment (Note 5)	1,248,676	1,260,172
Other Long-Term Assets		
Restricted cash	2,571	2,300
Deferred tax assets (Note 8)	1,438	1,407
Taxes receivable	10,907	18,535
Other long-term assets	7,037	7,163
Goodwill	102,581	102,581
Total Other Long-Term Assets	124,534	131,986
Total Assets	$1,878,003	$1,904,550
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$58,352	$72,400
Accrued liabilities	98,730	89,567
Taxes payable	13,455	102,887
Deferred tax liabilities (Note 8)	1,317	1,193
Asset retirement obligation (Note 7)	4,895	518
Total Current Liabilities	176,749	266,565
Long-Term Liabilities		
Deferred tax liabilities (Note 8)	179,504	177,082
Asset retirement obligation (Note 7)	15,206	21,455
Other long-term liabilities	11,394	9,540
Total Long-Term Liabilities	206,104	208,077
Contingencies (Note 9)		

Shareholders' Equity		
Common Stock (Note 6) (274,821,285 and 272,327,810 shares of Common Stock and 10,395,144 and 10,882,440 exchangeable shares, par value $0.001 per share, issued and outstanding as at June 30, 2014, and December 31, 2013, respectively)	10,189	10,187
Additional paid in capital	1,019,734	1,008,760
Retained earnings	465,227	410,961
Total Shareholders' Equity	1,495,150	1,429,908
Total Liabilities and Shareholders' Equity	$1,878,003	$1,904,550

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30,	
	2014	2013
Operating Activities		
Net income	$54,266	$105,696
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss from discontinued operations, net of income taxes (Note 3)	26,990	3,888
Depletion, depreciation, accretion and impairment	86,201	106,054
Deferred tax recovery (Note 8)	(841)	(15,715)
Non-cash stock-based compensation	2,624	4,110
Unrealized foreign exchange loss (gain)	4,567	(18,366)
Unrealized financial instruments gain	(351)	—
Equity tax	(1,642)	(1,718)
Other loss (Notes 9 and 10)	—	4,400
Net change in assets and liabilities from operating activities		
Accounts receivable and other long-term assets	(67,862)	(780)
Inventory	(9,348)	13,067
Prepaids	1,642	617
Accounts payable and accrued and other liabilities	9,747	(9,083)
Taxes receivable and payable	(77,306)	37,660
Net cash provided by operating activities of continuing operations	28,687	229,830
Net cash (used in) provided by operating activities of discontinued operations	(4,792)	18,950
Net cash provided by operating activities	23,895	248,780
Investing Activities		
Decrease (increase) in restricted cash	351	(4,285)
Additions to property, plant and equipment	(158,171)	(169,354)
Proceeds from sale of Argentina business unit, net of cash sold and transaction costs	42,755	—
Proceeds from sale of oil and gas properties (Note 5)	—	1,500
Net cash used in investing activities of continuing operations	(115,065)	(172,139)
Net cash used in investing activities of discontinued operations	(12,384)	(10,300)
Net cash used in investing activities	(127,449)	(182,439)
Financing Activities		
Proceeds from issuance of shares of Common Stock (Note 6)	7,113	3,013
Net cash provided by financing activities	7,113	3,013
Net (decrease) increase in cash and cash equivalents	(96,441)	69,354
Cash and cash equivalents, beginning of period	428,800	212,624
Cash and cash equivalents, end of period	$332,359	$281,978
Cash	$300,415	$279,377
Term deposits	31,944	2,601
Cash and cash equivalents, end of period	$332,359	$281,978

Supplemental cash flow disclosures:		
Cash paid for income taxes	$124,882	$12,631
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	$76,506	$62,377

(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, 2014	Year Ended December 31, 2013
Share Capital		
Balance, beginning of period	$10,187	$7,986
Issue of shares of Common Stock (Note 6)	2	2,201
Balance, end of period	10,189	10,187
Additional Paid in Capital		
Balance, beginning of period	1,008,760	998,772
Exercise of stock options (Note 6)	7,111	1,570
Stock-based compensation (Note 6)	3,863	8,418
Balance, end of period	1,019,734	1,008,760
Retained Earnings		
Balance, beginning of period	410,961	284,673
Net income	54,266	126,288
Balance, end of period	465,227	410,961
Total Shareholders' Equity	$1,495,150	$1,429,908

(See notes to the condensed consolidated financial statements)

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

1. Description of Business

Gran Tierra Energy Inc., a Nevada corporation (the "Company" or "Gran Tierra"), is a publicly traded oil and gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties. The Company's principal business activities are in Colombia, Peru and Brazil. Until June 25, 2014, the Company also had business activities in Argentina (Note 3).

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, 2013, included in the Company's 2013 Annual Report on Form 10-K, filed with the Securities and Exchange Commission ("SEC") on February 26, 2014.

The Company's significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company's 2013 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.

Discontinued Operations

During the three months ended June 30, 2014, the Company completed the sale of its Argentina business unit and the discontinued operations criteria of Accounting Standards Codification ("ASC") 205-20, "Discontinued Operations" were met. Therefore, the results of the Company's Argentina business unit are reflected separately as loss from discontinued operations, net of income taxes in the interim unaudited condensed consolidated statement of operations for the three and six months ended June 30, 2014 and 2013, on a line immediately after "Income from continuing operations." Amounts for 2013 have been reclassified to conform to the 2014 presentation. The reclassifications had no effect on net income. See Note 3, "Discontinued Operations," for additional disclosure. The Company did not recognize depletion, depreciation and accretion expenses subsequent to May 29, 2014, the date the assets were classified as held for sale.

Marketable Securities

The Company acquired investments in marketable securities in connection with the sale of its Argentina business unit. Marketable securities were classified as trading securities, in accordance with ASC 320, "Investments – Debt and Equity Securities", and are recorded in the consolidated balance sheet at fair value. The Company classifies trading securities as current or non-current based on the intent of management, the nature of the trading securities and whether they are readily available for use in current operations. Gains or losses on trading securities are recorded in the statement of operations as financial instruments gains or losses.

Foreign Currency Derivatives

The Company purchases Colombian peso non-deliverable forward contracts for purposes of fixing exchange rates at which it will purchase Colombian pesos to settle its income tax installment payments (Note 10). The Company does not intend to issue or hold derivative financial instruments for speculative trading purposes.

The Company records derivative instruments on the balance sheet as either an asset or liability measured at fair value. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Generally because of the short-term nature of the contracts and their limited use, the Company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in net income as financial instrument gains or losses in the interim unaudited condensed consolidated statement of operations. Cash settlements of the Company's derivative arrangements are classified as operating cash flows.

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

Recently Adopted Accounting Pronouncements

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

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

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

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

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

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

3. Discontinued Operations

On June 25, 2014, the Company, through several of its indirect subsidiaries (the “Selling Subsidiaries”), sold its Argentina business unit to Madalena Energy Inc. ("Madalena") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares.

The sale was made pursuant to agreements entered into by the Selling Subsidiaries (the “Agreements”); specifically, pursuant to the Agreements: (1) Madalena agreed to acquire from Gran Tierra Argentina Holdings ULC, an Alberta corporation (“GTE ULC”), and PCESA Petroleros Canadienses de Ecuador S.A., an Ecuador corporation (“PCESA”), both indirect subsidiaries of the Company, all of the outstanding shares of the Company’s indirect subsidiaries Gran Tierra Energy Argentina S.R.L. (“GTE Argentina”) and P.E.T.J.A. S.A, and agreed to acquire certain debt owed by GTE Argentina, for (a) approximately $44.8 million in cash, plus certain other adjustments and interest, and (b) shares of Madalena stock valued at $13.9 million; and (2) Madalena agreed to acquire from Gran Tierra Petroco Inc., an Alberta corporation ("Petroco"), an indirect subsidiary of the Company, all of the outstanding shares of the Company's indirect subsidiary Petrolifera Petroleum Limited ("PPL"), and agreed to acquire certain debt owed by PPL , for approximately $10.6 million in cash, plus certain other adjustments and interest. Collectively, GTE Argentina, P.E.T.J.A. S.A., PPL and PPL's subsidiaries held all of the assets of the Gran Tierra Energy Argentina business unit.

Accordingly, the results of the Company's Argentina business unit are classified as "Loss from discontinued operations, net of income taxes" on the consolidated statements of operations for the three and six months ended June 30, 2014, and 2013. Amounts for 2013 have been reclassified to conform to the 2014 presentation. The reclassifications had no effect on net income.

Revenue and other income and loss from discontinued operations for the three and six months ended June 30, 2014, and 2013, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2014	2013	2014	2013
Revenue and other income	$ 14,161	$ 18,234	$ 31,985	$ 37,020
Loss from operations of discontinued operations before income taxes	$ (2,079)	$ (424)	$ (6,252)	$ (2,089)
Income tax expense	(988)	(1,377)	(1,458)	(1,799)
Loss from operations of discontinued operations	(3,067)	(1,801)	(7,710)	(3,888)
Loss on sale before income taxes	(18,235)	—	(18,235)	—
Income tax expense	(1,045)	—	(1,045)	—
Loss on sale	(19,280)	—	(19,280)	—
Loss from discontinued operations, net of income taxes	$ (22,347)	$ (1,801)	$ (26,990)	$ (3,888)

The Company did not meet the criteria to classify the Argentina business unit as held for sale at March 31, 2014, or prior periods. The cost center ceiling with respect to the Company's Argentina full cost pool exceeded the net capitalized cost of the cost center at March 31, 2014, and as such, no ceiling test writedown was required. In the year ended December 31, 2013, the Company recorded a ceiling test impairment loss of $30.8 million in the Company's Argentina cost center as a result of deferred investment and inconclusive waterflood results.

At December 31, 2013, assets and liabilities related to discontinued operations were as follows:

	As at
(Thousands of U.S. Dollars)	December 31, 2013
Current assets (1)	$ 39,125
Property, plant and equipment	94,446
Other long-term assets	1,839
	$ 135,410
Current liabilities	$ 37,612
Long-term liabilities	9,755
	$ 47,367

(1) Included cash of $21.2 million.

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, Peru and Brazil based on geographic organization. Prior to classifying the Company's Argentina business unit as discontinued operations (Note 3), Argentina was a reportable segment. The level of activity in Brazil was not significant at June 30, 2014, or December 31, 2013; 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 amounts disclosed in the tables below exclude the results of the Argentina business unit unless otherwise noted. Certain subsidiaries which were previously included in the All Other category were sold as part of the Argentina business unit, and therefore amounts disclosed in the All Other category have been reclassified to exclude amounts reported in loss from discontinued operations. The Company evaluates reportable segment performance based on income or loss from continuing operations before income taxes.

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

	Three Months Ended June 30, 2014				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$139,350	$—	$8,538	$—	$147,888
Interest income	184	—	434	20	638
Depletion, depreciation, accretion and impairment	39,348	103	2,241	245	41,937
Depletion, depreciation, accretion and impairment - per unit of production	26.14	—	25.12	—	26.30
Income (loss) from continuing operations before income taxes	62,481	(2,408)	3,750	(3,952)	59,871
Segment capital expenditures	45,688	41,912	3,433	306	91,339

	Three Months Ended June 30, 2013				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$144,333	$—	$5,917	$—	$150,250
Interest income	143	12	2	167	324
Depletion, depreciation, accretion and impairment	48,364	137	6,843	248	55,592
Depletion, depreciation, accretion and impairment - per unit of production	29.01	—	102.20	—	32.06
Income (loss) from continuing operations before income taxes	84,470	(2,353)	(2,887)	(4,686)	74,544
Segment capital expenditures (1)	48,743	19,601	19,981	228	88,553

	Six Months Ended June 30, 2014				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$284,285	$—	$14,708	$—	$298,993
Interest income	321	—	859	208	1,388
Depletion, depreciation, accretion and impairment	80,598	311	4,820	472	86,201
Depletion, depreciation, accretion and impairment - per unit of production	25.78	—	30.99	—	26.26
Income (loss) from continuing operations before income taxes	148,492	(4,466)	5,700	(10,374)	139,352
Segment capital expenditures	96,231	62,805	13,799	605	173,440

	Six Months Ended June 30, 2013				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$324,336	$—	$12,154	$—	$336,490
Interest income	304	26	11	330	671
Depletion, depreciation, accretion and impairment	94,320	199	11,014	521	106,054
Depletion, depreciation, accretion and impairment - per unit of production	27.63	—	84.21	—	29.92
Income (loss) from continuing operations before income taxes	186,138	(3,580)	(3,326)	(7,671)	171,561
Segment capital expenditures (1)	79,150	48,848	34,520	239	162,757

(1) In 2013, segment capital expenditures are net of proceeds of $1.5 million relating to the Company's sale of its 15% working interest in the Mecaya Block in Colombia (Note 5).

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(Thousands of U.S. Dollars)	As at June 30, 2014 Colombia	Peru	Brazil	All Other	Total Excluding Discontinued Operations	Discontinued Operations	Total
Property, plant and equipment	$861,331	$241,025	$143,226	$3,094	$1,248,676	$—	$1,248,676
Goodwill	102,581	—	—	—	102,581	—	102,581
All other assets	247,012	30,211	24,747	224,776	526,746	—	526,746
Total Assets	$1,210,924	$271,236	$167,973	$227,870	$1,878,003	$—	$1,878,003

(Thousands of U.S. Dollars)	As at December 31, 2013 Colombia	Peru	Brazil	All Other	Total Excluding Discontinued Operations	Discontinued Operations	Total
Property, plant and equipment	$850,359	$178,531	$133,874	$2,962	$1,165,726	$94,446	$1,260,172
Goodwill	102,581	—	—	—	102,581	—	102,581
All other assets	233,336	24,240	24,477	218,780	500,833	40,964	541,797
Total Assets	$1,186,276	$202,771	$158,351	$221,742	$1,769,140	$135,410	$1,904,550

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

In the six months ended June 30, 2014, the Company had two significant customers in Colombia: Ecopetrol S.A. ("Ecopetrol") and one other customer, which accounted for 52% and 38%, respectively, of the Company's consolidated oil and natural gas sales from continuing operations. For the three months ended June 30, 2014, these customers accounted for 54% and 33%, respectively, of the Company's consolidated oil and natural gas sales from continuing operations. For the three and six months ended June 30, 2013, sales to Ecopetrol accounted for 48% and 54% and sales to the other customer accounted for 44% and 32% respectively, of the Company's consolidated oil and natural gas sales from continuing operations.

5. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at June 30, 2014 Cost	Accumulated depletion, depreciation and impairment	Net book value	As at December 31, 2013 Cost	Accumulated depletion, depreciation and impairment	Net book value
Oil and natural gas properties						
Proved	$1,870,800	$(1,110,317)	$760,483	$1,799,544	$(1,005,475)	$794,069
Unproved	479,075	—	479,075	456,001	—	456,001
	2,349,875	(1,110,317)	1,239,558	2,255,545	(1,005,475)	1,250,070

Furniture and fixtures and leasehold improvements	8,656	(6,567)	2,089	8,919	(6,568)	2,351
Computer equipment	12,954	(6,391)	6,563	14,786	(7,605)	7,181
Automobiles	802	(336)	466	1,381	(811)	570
Total Property, Plant and Equipment	$2,372,287	$(1,123,611)	$1,248,676	$2,280,631	$(1,020,459)	$1,260,172

Depletion and depreciation expense from continuing operations on property, plant and equipment for the three months ended June 30, 2014, was $46.2 million (three months ended June 30, 2013 - $51.8 million) and for the six months ended June 30, 2014, was $90.5 million (six months ended June 30, 2013 - $98.8 million). A portion of depletion and depreciation expense was recorded as inventory in each period and adjusted for inventory changes. In the second quarter of 2013, the Company recorded a ceiling test impairment loss of $2.0 million in the Company's Brazil cost center as a result of lower realized prices and increased operating costs.

On August 6, 2014, the Company announced proved reserves, net after royalty and calculated in accordance with SEC rules as of May 31, 2014, for the Tiê field, in Brazil increased after production for the five months ended May 31, 2014, to 3.0 MMBOE from 1.7 MMBOE, proved and probable reserves increased to 4.9 MMBOE from 3.3 MMBOE and proved, probable and possible reserves increased to 7.2 MMBOE from 5.0 MMBOE. The reserve revisions were due to new production from the Agua Grande formation, results of seismic reprocessing, and additional reservoir volume in the Sergi formation.

In the second quarter of 2013, the Company received proceeds of $1.5 million relating to a sale of its 15% working interest in the Mecaya Block in Colombia.

In Brazil, the exploration phase of the concession agreements on Blocks REC-T-129, REC-T-142 and REC-T-155 were each due to expire on November 24, 2013, and the exploration phase of the concession agreement on Block REC-T-224 was due to expire on December 11, 2013; however, under the concession agreements the Company was able and did submit applications to the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") for extensions or suspensions of the exploration phases of these blocks. The Company has not yet received a decision from the ANP regarding these extension or suspension applications. At June 30, 2014, unproved properties included $59.0 million relating to exploration expenditures on these four blocks. Management assessed these blocks for impairment at June 30, 2014, and concluded no impairment had occurred.

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Peru and Brazil. As at June 30, 2014, the Company had $162.0 million (December 31, 2013 - $176.1 million) of unproved assets in Colombia, $239.8 million (December 31, 2013 - $177.5 million) of unproved assets in Peru, and $77.3 million (December 31, 2013 - $84.2 million) of unproved assets in Brazil for a total of $479.1 million (December 31, 2013 - $437.8 million). At December 31, 2013, the Company had $18.2 million of unproved assets in Argentina, which were sold as part of the sale of the Argentina business unit during the six months ended June 30, 2014 (Note 3). Unproved oil and natural gas 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 warrants whether or not future areas will be developed.

Inventory

At June 30, 2014, oil and supplies inventories were $23.0 million and $2.4 million, respectively (December 31, 2013 - $11.7 million and $2.0 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, 2014, outstanding share capital consists of 274,821,285 shares of Common Stock of the Company, 5,861,017 exchangeable shares of Gran Tierra Exchangeco Inc., (the "Exchangeco exchangeable shares") and 4,534,127 exchangeable shares of Gran Tierra Goldstrike Inc. (the "Goldstrike exchangeable shares"). The redemption date for the Exchangeco exchangeable shares and the Goldstrike exchangeable shares is a date to be established by the applicable Board of Directors. During the six months ended June 30, 2014, 2,006,179 shares of Common Stock were issued upon the exercise of stock options and 487,296 shares of Common Stock were issued upon the exchange of the Exchangeco exchangeable shares.

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

Restricted Stock Units and Stock Options

The Company grants time-vested restricted stock units ("RSUs") to certain officers, employees and consultants. Additionally, the Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. The following table provides information about RSU and stock option activity for the six months ended June 30, 2014:

	RSUs Number of Outstanding Share Units	Options Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2013	922,045	15,668,458	5.41
Granted	843,455	2,246,775	7.09
Exercised	(409,931)	(2,006,179)	(3.55)
Forfeited	(32,516)	(138,532)	(6.55)
Expired	—	(140,318)	(6.92)
Balance, June 30, 2014	1,323,053	15,630,204	5.87

For the six months ended June 30, 2014, 2,006,179 shares of Common Stock were issued for cash proceeds of $7.1 million upon the exercise of 2,006,179 stock options (six months ended June 30, 2013 - $3.0 million).

The weighted average grant date fair value for options granted in the three months ended June 30, 2014, was $2.38 (three months ended June 30, 2013 - $2.66) and for the six months ended June 30, 2014, was $2.51 (six months ended June 30, 2013 - $2.65).

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

(Thousands of U.S. Dollars)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Compensation costs for stock options	$ 1,847	$ 1,932	$ 3,863	$ 4,181
Compensation costs for RSUs	2,397	619	3,641	619
	4,244	2,551	7,504	4,800
Less: stock-based compensation costs capitalized	(1,039)	(202)	(1,822)	(384)
Stock-based compensation costs expensed	$ 3,205	$ 2,349	$ 5,682	$ 4,416

Of the total compensation expense for the three months ended June 30, 2014, $2.0 million (three months ended June 30, 2013 - $2.0 million) was recorded in G&A expenses, $0.1 million (three months ended June 30, 2013 – $0.1 million) was recorded in operating expenses and $1.1 million (three months ended June 30, 2013 – $0.2 million) was recorded in loss from discontinued operations. Of the total compensation expense for the six months ended June 30, 2014, $4.1 million (six months ended June 30, 2013 – $3.8 million) was recorded in G&A expenses, $0.3 million (six months ended June 30, 2013 – $0.3 million) was recorded in operating expenses and $1.3 million (six months ended June 30, 2013 - $0.3 million) was recorded in loss from discontinued operations.

At June 30, 2014, there was $12.7 million (December 31, 2013 - $8.1 million) of unrecognized compensation cost related to unvested stock options and RSUs which is expected to be recognized over a weighted average period of 2.0 years. The vesting of certain RSUs and stock options was accelerated as a result of the sale of the Argentina business unit (Note 3).

Income per share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Weighted average number of common and exchangeable shares outstanding	283,773,204	282,822,383	283,505,690	282,482,343
Weighted average shares issuable pursuant to stock options	13,373,568	10,400,550	13,462,797	5,610,297
Weighted average shares assumed to be purchased from proceeds of stock options	(9,289,813)	(7,773,225)	(8,629,789)	(2,445,877)
Weighted average number of diluted common and exchangeable shares outstanding	287,856,959	285,449,708	288,338,698	285,646,763

For the three months ended June 30, 2014, 3,137,840 options (three months ended June 30, 2013 - 5,282,205 options) were excluded from the diluted income per share calculation as the options were anti-dilutive. For the six months ended June 30, 2014, 3,137,840 options (six months ended June 30, 2013 - 10,902,358 options) were excluded from the diluted income per share calculation as the options were anti-dilutive.

7. 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)	June 30, 2014	December 31, 2013
Balance, beginning of year	$21,973	$18,292
Settlements	—	(2,068)
Liability incurred	5,154	2,623
Liabilities associated with the Argentina business unit sold (Note 3)	(10,170)	—
Foreign exchange	7	(25)
Accretion	782	1,279
Revisions in estimated liability	2,355	1,872
Balance, end of period	$20,101	$21,973
Asset retirement obligation - current	$4,895	$518
Asset retirement obligation - long-term	15,206	21,455
Balance, end of period	$20,101	$21,973

Revisions to estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. At June 30, 2014, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was $2.1 million (December 31, 2013 - $1.9 million). These assets are included in restricted cash on the Company's interim unaudited condensed balance sheet.

8. Taxes

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

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2014	2013
Income (loss) from continuing operations before income taxes		
United States	$(10,791)	$(4,631)
Foreign	150,143	176,192
	139,352	171,561
	35%	35%
Income tax expense from continuing operations expected	48,773	60,046
Foreign currency translation adjustments	161	(5,262)
Impact of foreign taxes	(1,803)	(1,686)
Other local taxes	2,014	751
Stock-based compensation	1,397	1,043
Increase in valuation allowance	294	2,766
Non-deductible third party royalty in Colombia	4,505	5,749
Other permanent differences	2,755	(1,430)
Total income tax expense from continuing operations	$58,096	$61,977
Current income tax expense from continuing operations		
United States	$721	$726
Foreign	58,216	76,966
	58,937	77,692
Deferred income tax recovery from continuing operations		
Foreign	(841)	(15,715)
Total income tax expense from continuing operations	$58,096	$61,977

(Thousands of U.S. Dollars)	As at June 30, 2014	December 31, 2013
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	$35,780	$47,154
Tax basis in excess of book basis	42,412	59,168
Foreign tax credits and other accruals	18,142	34,894
Tax benefit of capital loss carryforwards	28,792	4,769
Deferred tax assets before valuation allowance	125,126	145,985
Valuation allowance	(122,324)	(142,322)
	$2,802	$3,663
Deferred tax assets - current	$1,364	$2,256
Deferred tax assets - long-term	1,438	1,407
	2,802	3,663
Deferred tax liabilities - current	(1,317)	(1,193)
Deferred tax liabilities - long-term	(179,504)	(177,082)
	(180,821)	(178,275)
Net Deferred Tax Liabilities	$(178,019)	$(174,612)

As at June 30, 2014, the Company had operating loss carryforwards of $118.7 million (December 31, 2013 - $215.4 million) and capital loss carryforwards of $224.7 million (December 31, 2013 – $32.6 million) before valuation allowance. Of these operating loss carryforwards and capital loss carryforwards, $304.5 million (December 31, 2013 - $213.8 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between

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2014 and 2034 and the capital loss carryforwards expire between 2016 and 2017, while certain other jurisdictions allow operating and capital losses to be carried forward indefinitely.

As at June 30, 2014, the total amount of Gran Tierra’s unrecognized tax benefit related to continuing operations was $4.0 million (December 31, 2013 - $2.9 million), which if recognized would affect the Company’s effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations.

Changes in the Company's unrecognized tax benefit relating to continuing operations are as follows:

	Six Months Ended June 30,	
	2014	2013
(Thousands of U.S. Dollars)		
Unrecognized tax benefit relating to continuing operations at beginning of period	$2,900	$5,900
Increases for positions relating to prior year	1,100	—
Unrecognized tax benefit relating to continuing operations at end of period	$4,000	$5,900

The Company and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for the tax years 2006 through 2013 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

At June 30, 2014, and December 31, 2013, accounts payable included the remaining unpaid balance of equity tax liability of $1.7 million (December 31, 2013 - $3.3 million), a Colombian tax of 6% on a legislated measure 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.

9. Contingencies

Gran Tierra Energy Colombia, Ltd. and Petrolifera Petroleum (Colombia) Ltd (collectively “GTEC”) and Ecopetrol, the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long-term test of the Guayuyaco-1 and Guayuyaco-2 wells, prior to GTEC's purchase of the companies originally involved in the dispute. There has been no agreement between the parties, and Ecopetrol filed a lawsuit in the Contravention Administrative Tribunal in the District of Cauca (the "Tribunal") regarding this matter. During the first quarter of 2013, the Tribunal ruled in favor of Ecopetrol and awarded Ecopetrol 44,025 bbl of oil. GTEC has filed an appeal of the ruling to the Supreme Administrative Court (Consejo de Estado) in a second instance procedure. During the three months ended March 31, 2013, based on market oil prices in Colombia, Gran Tierra accrued $4.4 million in the interim unaudited condensed consolidated financial statements in relation to this dispute (Note 10).

Gran Tierra’s production from the Costayaco Exploitation Area is subject to an additional royalty (the "HPR royalty"), which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Block exploration and production contract (the "Chaza Contract") and the sales price. The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract and filed an arbitration claim seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. The ANH filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH's responses to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. As at June 30, 2014, total cumulative production from the Moqueta Exploitation Area was 3.2 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $52.9 million. At this time no amount has been accrued in the interim unaudited condensed consolidated financial statements nor deducted from the Company's reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH's interpretation is correct could be up to $35.6 million as at June 30, 2014. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

The Company provided the purchaser of its Argentina business unit with certain indemnifications. The Company remains responsible for certain contingent liabilities related to such indemnifications, subject to defined limitations. The Company does not believe that these obligations are probable of having a material impact on its consolidated financial position, results of operations or cash flows.

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

Letters of credit

At June 30, 2014, the Company had provided promissory notes totaling $67.7 million (December 31, 2013 - $52.5 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

10. Financial Instruments, Fair Value Measurements, Credit Risk and Foreign Exchange Risk

Financial Instruments

At June 30, 2014, the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, trading securities, accounts payable, accrued liabilities, foreign currency derivatives included in current assets and contingent consideration and contingent liability included in other long-term liabilities.

Fair Value Measurement

The fair value of the trading securities, foreign currency derivatives, contingent consideration and contingent liability are being remeasured at the estimated fair value at each reporting period.

The fair value of the trading securities which were received as consideration on the sale of the Company's Argentina business unit (Note 3) was estimated based on quoted market prices in an active market.

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

The fair value of the contingent consideration, which relates to the acquisition of the remaining 30% working interest in certain properties in Brazil, was estimated based on the consideration expected to be transferred and discounted back to present value by applying an appropriate discount rate that reflected the risk factors associated with the payment streams. The discount rate used is determined in accordance with accepted valuation methods.

The fair value of the contingent liability which relates to a dispute with Ecopetrol (Note 9) was estimated based on the fair value of the amount awarded using market oil prices in Colombia.

The fair value of the trading securities, foreign currency derivatives, contingent consideration and the contingent liability related to the Ecopetrol dispute at June 30, 2014, and December 31, 2013, were as follows:

(Thousands of U.S. Dollars)	As at June 30, 2014	December 31, 2013
Trading securities (Note 3)	$ 14,251	$—
Foreign currency derivatives	12	—
Contingent consideration	1,061	1,061
Contingent liability (Note 9)	4,400	4,400

The following table presents gains or losses on financial instruments recognized in the accompanying interim unaudited condensed consolidated statements of operations:

(Thousands of U.S. Dollars)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Trading securities gain	$ 339	$—	$ 339	$—
Foreign currency derivatives gain	2,265	—	4,674	—
	$ 2,604	$—	$ 5,013	$—

These gains are presented as financial instruments gain in the interim unaudited condensed consolidated statements of operations and cash flows.

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, 2014, the fair value of the trading securities acquired in connection with the disposal of the Argentina business unit (Note 3) was determined using Level 1 inputs. At June 30, 2014, the fair value of the foreign currency derivatives was determined using Level 2 inputs. At June 30, 2014, and December 31, 2013, the fair value of the contingent consideration payable in connection with the Brazil acquisition was determined using Level 3 inputs and the fair value of the contingent liability which relates to a dispute with Ecopetrol (Note 9) was determined using Level 1 inputs. The disclosure in the paragraph below regarding the fair value of cash and restricted cash is based on Level 1 inputs.

The Company's non-recurring fair value measurements include asset retirement obligations. The fair value of an asset retirement obligation is measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. The significant level 3 inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit-adjusted risk-free interest rate, inflation rates and estimated dates of abandonment. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value, while the asset retirement cost is amortized over the estimated productive life of the related assets.

Credit Risk

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

At June 30, 2014, cash and cash equivalents and restricted cash included balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with financial institutions with strong investment grade ratings or governments, or the equivalent in the Company's operating areas.

The Company purchases non-deliverable forward contracts for purposes of fixing exchange rates at which it will purchase Colombian pesos to settle its income tax installment payments. With the exception of these foreign currency derivatives, any foreign currency transactions are conducted on a spot basis with major financial institutions in the Company's operating areas.

At June 30, 2014, the Company had the following open foreign currency derivative position:
Forward contracts

Currency	Contract Type	Notional (Millions of Colombian Pesos)	Weighted Average Fixed Rate Received (Colombian Pesos - U.S. Dollars)	Expiration
Colombian pesos	Buy	712.2	1,976	February 2015

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 six months ended June 30, 2014, the Company had two customers that were significant to the Colombian segment and one customer that was significant to the Brazilian segment.

To reduce the concentration of exposure to any individual counterparty, the Company utilizes a group of investment-grade rated counterparties, primarily financial institutions, for its derivative transactions. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its foreign currency derivative instruments.

For the six months ended June 30, 2014, 95% (six months ended June 30, 2013 - 96%) of the Company's revenue and other income from continuing operations was generated in Colombia.

Foreign Exchange Risk

Unrealized foreign exchange gains and losses result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, which are monetary liabilities mainly denominated in the local currency of the Colombian 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 $96,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

In Colombia, the company receives 100% of its revenues in U.S. dollars and the majority of its capital expenditures are in U.S. dollars or are based on U.S. dollar prices. In Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of the Company's capital expenditures within Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. In Peru, capital expenditures are based on U.S. dollar prices and may be paid in local currency or U.S. dollars.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management’s Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our Annual Report on Form 10-K, filed with the U.S. Securities and Exchange Commission (“SEC”) on February 26, 2014.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America with business units in Colombia, Peru and Brazil, and we are headquartered in Calgary, Alberta, Canada. For the six months ended June 30, 2014, 95% (six months ended June 30, 2013 - 96%) of our revenue and other income from continuing operations was generated in Colombia.

On June 25, 2014, we sold our Argentina business unit to Madalena Energy Inc. ("Madalena") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares. The decision to sell our Argentina business unit followed recent significant exploration success in Peru, ongoing success in Colombia and ongoing evaluations in Brazil and was due to a decision to focus our human and capital resources in areas that we believe will provide the greatest return for our shareholders and drive growth in the future. In accordance with generally accepted accounting principles in the United States of America, we met the criteria to classify our Argentina business unit as discontinued operations in the second quarter of 2014. As such, the results of operations for our Argentina business unit are reflected as loss from discontinued operations, net of income taxes and discussed further in Note 3, "Discontinued Operations," of our interim unaudited condensed consolidated financial statements for the three and six months ended June 30, 2014.

In this Management’s Discussion and Analysis of Financial Condition and Results of Operations, unless otherwise stated production represents production volumes NAR adjusted for inventory changes and losses.

Highlights

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
Production (BOEPD) (1)(2)	17,524	19,058	(8)	18,135	19,583	(7)
Prices Realized - per BOE (1)	$92.74	$86.64	7	$91.09	$94.94	(4)
Revenue and Other Income ($000s) (1)	$148,526	$150,574	(1)	$300,381	$337,161	(11)
Income from Continuing Operations ($000s) (1)	$31,484	$49,584	(37)	$81,256	$109,584	(26)
Loss from Discontinued Operations, Net of Income Taxes ($000s)	$(22,347)	$(1,801)	—	$(26,990)	$(3,888)	594
Net Income ($000s)	$9,137	$47,783	(81)	$54,266	$105,696	(49)
Income (loss) Per Share - Basic						
Income from Continuing Operations (1)	$0.11	$0.18	(39)	$0.29	$0.38	(24)
Loss from Discontinued Operations, Net of Income Taxes	(0.08)	(0.01)	700	(0.10)	(0.01)	900
Net income	$0.03	$0.17	(82)	$0.19	$0.37	(49)
Income (loss) Per Share - Diluted						
Income from Continuing Operations (1)	$0.11	$0.18	(39)	$0.28	$0.38	(26)
Loss from Discontinued Operations, Net of Income Taxes	(0.08)	(0.01)	700	(0.09)	(0.01)	800
Net income	$0.03	$0.17	(82)	$0.19	$0.37	(49)
Funds Flow From Continuing Operations ($000s) (1)(3)	$85,145	$85,836	(1)	$171,814	$188,349	(9)
Capital Expenditures For Continuing Operations ($000s) (1)	$91,339	$88,553	3	$173,440	$162,757	7

	As at		
	June 30, 2014	December 31, 2013	% Change
Cash & Cash Equivalents ($000s)	$332,359	$428,800	(22)

Working Capital (including cash & cash equivalents) ($000s)	$328,044	$245,827	33	
Property, Plant & Equipment ($000s)	$1,248,676	$1,260,172	(1	)

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(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes, associated with discontinued operations was 2,426 BOEPD and 2,744 BOEPD for the three and six months ended June 30, 2014, and 3,073 BOEPD and 3,192 BOEPD for the corresponding periods in 2013. Argentina production for the three and six months ended June 30, 2014, was calculated to the date of sale of June 25, 2014.

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

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

Funds Flow From Continuing Operations - Non-GAAP Measure ($000s)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Net income	$9,137	$47,783	$54,266	$105,696
Adjustments to reconcile net income to funds flow from continuing operations				
Loss from discontinued operations, net of income taxes	22,347	1,801	26,990	3,888
DD&A expenses	41,937	55,592	86,201	106,054
Deferred tax expense (recovery)	1,419	(8,213)	(841)	(15,715)
Non-cash stock-based compensation	1,144	2,213	2,624	4,110
Unrealized foreign exchange loss (gain)	8,745	(11,622)	4,567	(18,366)
Unrealized financial instruments loss (gain)	2,058	—	(351)	—
Equity tax	(1,642)	(1,718)	(1,642)	(1,718)
Other loss	—	—	—	4,400
Funds flow from continuing operations	$85,145	$85,836	$171,814	$188,349

- For the three and six months ended June 30, 2014, oil and gas production NAR before inventory adjustments and losses increased to 19,857 and 19,445 BOEPD compared with 19,373 and 19,004 BOEPD in the corresponding periods in 2013, respectively. In 2014, production from new wells in the Moqueta field in the Chaza Block and new wells in the Llanos-22 Block and fewer days of pipeline disruptions had a positive effect on production NAR before inventory adjustments and losses in Colombia.

- For the three and six months ended June 30, 2014, oil and gas production, NAR and adjusted for inventory changes and losses, decreased by 8% to 17,524 BOEPD and by 7% to 18,135 BOEPD compared with the corresponding periods in 2013, respectively, due to inventory changes. During the three and six months ended June 30, 2014, a net inventory increase accounted for 0.2 MMbbl or 2,333 bopd and 0.2 MMbbl or 1,310 bopd of reduced production compared with a net inventory reduction in the six months ended June 30, 2013, which accounted for 0.1 MMbbl or 578 bopd of increased production. In the three and six months ended June 30, 2014, production was 82% from the

Chaza Block in Colombia.

- For the three and six months ended June 30, 2014, revenue and other income decreased by 1% to $148.5 million and by 11% to $300.4 million compared with $150.6 million and $337.2 million in the corresponding periods in 2013, respectively. The decrease was primarily due to higher inventory and the effect of changes in realized prices. The average price realized per BOE increased by 7% to $92.74 and decreased by 4% to $91.09 for the three and six months ended June 30, 2014, from $86.64 and $94.94, in the comparable periods in 2013, respectively.

- Income from continuing operations was $31.5 million, or $0.11 per share basic and diluted, and $81.3 million, or $0.29 per share basic and $0.28 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with $49.6 million, or $0.18 per share basic and diluted, and $109.6 million, or $0.38 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three months ended June 30, 2014, decreased oil and natural gas sales as a result of higher inventory, and higher operating, general and administrative ("G&A") and income tax expenses and foreign exchange losses, were only partially offset by decreased DD&A expenses and financial instruments gains. For the six months ended June 30, 2014, decreased oil and natural gas sales, increased G&A expenses and foreign exchange losses were only partially offset by lower operating, DD&A and income tax expenses, financial instruments gains and the absence of other loss.

- Loss from discontinued operations, net of income taxes, was $22.3 million, or $0.08 per share basic and diluted, and $27.0 million, or $0.10 per share basic and $0.09 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with loss of $1.8 million, or $0.01 per share basic and diluted, and $3.9 million, or $0.01 per share basic and diluted, in the corresponding periods in 2013, respectively. Loss from discontinued operations, net of income taxes, increased compared with the corresponding period in 2013 due to the recognition of a loss on sale of the Argentina business unit of $19.3 million in the three and six months ended June 30, 2014.

- Net income was $9.1 million, or $0.03 per share basic and diluted, and $54.3 million, or $0.19 per share basic and diluted, for the three and six months ended June 30, 2014, respectively, compared with $47.8 million, or $0.17 per share basic and diluted, and $105.7 million, or $0.37 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three and six months ended June 30, 2014, the decrease was due to lower income from continuing operations and the recognition of a loss on sale of the Argentina business unit.

- For the three and six months ended June 30, 2014, funds flow from continuing operations decreased by 1% to $85.1 million and by 9% to $171.8 million, respectively. For the three months ended June 30, 2014, decreased oil and natural gas sales, and higher operating, G&A and income tax expenses and realized foreign exchange losses, were only partially offset by realized financial instruments gains. For the six months ended June 30, 2014, decreased oil and natural gas sales, increased G&A expenses and realized foreign exchange losses were only partially offset by lower operating and income tax expenses and realized financial instruments gains.

- Cash and cash equivalents were $332.4 million at June 30, 2014, compared with $428.8 million at December 31, 2013. The decrease in cash and cash equivalents during the six months ended June 30, 2014, was primarily the result of cash capital expenditures of $158.2 million, cash used in investing activities of discontinued operations of $12.4 million and a $143.1 million change in assets and liabilities from operating activities, partially offset by funds flow from continuing operations of $171.8 million, net proceeds from sale of Argentina business unit of $42.8 million, cash used in operating activities of discontinued operations of $4.8 million and proceeds from the issuance of shares of common stock of $7.1 million.

- Working capital (including cash and cash equivalents) was $328.0 million at June 30, 2014, an $82.2 million increase from December 31, 2013.

- Property, plant and equipment ("PPE") at June 30, 2014, was $1.2 billion, a decrease of $11.5 million from December 31, 2013, as a result of the sale of the Argentina business unit PPE of $100.2 million, $90.5 million of depletion, depreciation and impairment expenses related to continuing operations, $12.9 million of depletion, depreciation and impairment expenses recorded in loss from discontinued operations, partially offset by $173.4 million of capital expenditures related to continuing operations and $18.7 million of capital expenditures related to discontinued operations.

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Capital expenditures for continuing operations for the six months ended June 30, 2014, were $173.4 million compared with $162.8 million for the six months ended June 30, 2013. In 2014, these capital expenditures included drilling of $116.6 million, geological and geophysical (“G&G”) expenditures of $26.8 million, facilities of $14.2 million and other expenditures of $15.8 million.

Business Environment Outlook

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

We believe our current operations and 2014 capital expenditure program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including additional pipeline delivery restrictions and other oil transportation disruptions in Colombia or a downturn in oil and gas prices, we would examine measures such as capital expenditure program reductions, use of our revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. Continuing global social and political uncertainty, economic uncertainty in the Middle East, United States, Europe and Asia and changes in global supply and infrastructure are having an impact on world markets, and we are unable to determine the impact, if any, these events may have on oil prices and demand. The timing and execution of our capital expenditure program are also affected by the availability of services from third party oil field contractors and our ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities. Any delay may affect our ability to execute our capital expenditure program.

We have noted recently that in the Department of Putumayo in Colombia where we operate, additional efforts are being made by new ethnic groups to utilize the courts to require that they be consulted, and obtain benefits, despite a company's prior compliance with the legislated consultation process and the receipt of the necessary permits to drill and operate. See "Risk Factors: 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."

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

Consolidated Results of Operations

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales (1)	$147,888	$150,250	(2)	$298,993	$336,490	(11)
Interest income (1)	638	324	97	1,388	671	107
	148,526	150,574	(1)	300,381	337,161	(11)
Operating expenses (1)	25,346	23,970	6	47,212	56,013	(16)
DD&A expenses (1)	41,937	55,592	(25)	86,201	106,054	(19)
G&A expenses (1)	13,932	9,090	53	26,795	18,112	48
Foreign exchange loss (gain) (1)	10,044	(12,622)	180	5,834	(18,979)	(131)
Financial instruments gain (1)	(2,604)	—	—	(5,013)	—	—
Other loss (1)	—	—	—	—	4,400	(100)
	88,655	76,030	17	161,029	165,600	(3)
Income from continuing operations before income taxes (1)	59,871	74,544	(20)	139,352	171,561	(19)
Income tax expense (1)	(28,387)	(24,960)	14	(58,096)	(61,977)	(6)
Income from continuing operations (1)	$31,484	$49,584	(37)	$81,256	$109,584	(26)
Loss from discontinued operations, net of income taxes	(22,347)	(1,801)	—	(26,990)	(3,888)	594
Net income	$9,137	$47,783	(81)	$54,266	$105,696	(49)
Production (1)(2)						
Oil and NGL's, bbl	1,573,071	1,732,514	(9)	3,250,049	3,542,674	(8)
Natural gas, Mcf	129,711	10,468	—	194,490	10,468	—
Total production, BOE	1,594,690	1,734,259	(8)	3,282,464	3,544,419	(7)
Average Prices (1)						
Oil and NGL's per bbl	$93.72	$86.71	8	$91.74	$94.99	(3)
Natural gas per Mcf	$4.01	$7.18	(44)	$4.79	$7.18	(33)
Consolidated Results of Operations per BOE						
Oil and natural gas sales (1)	$92.74	$86.64	7	$91.09	$94.94	(4)
Interest income (1)	0.40	0.19	111	0.42	0.19	121
	93.14	86.83	7	91.51	95.13	(4)
Operating expenses (1)	15.89	13.82	15	14.38	15.80	(9)
DD&A expenses (1)	26.30	32.06	(18)	26.26	29.92	(12)
G&A expenses (1)	8.74	5.24	67	8.16	5.11	60
Foreign exchange loss (gain) (1)	6.30	(7.28)	187	1.78	(5.35)	(133)
Financial instruments gain (1)	(1.63)	—	—	(1.53)	—	—

Other loss (1)	—	—	—	—	1.24	(100)
	55.60	43.84	27	49.05	46.72	5
Income from continuing operations before income taxes (1)	37.54	42.99	(13)	42.46	48.41	(12)
Income tax expense (1)	(17.80)	(14.39)	24	(17.70)	(17.49)	1
Income from continuing operations (1)	$19.74	$28.60	(31)	$24.76	$30.92	(20)

(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes, associated with discontinued operations was 2,426 BOEPD and 2,744 BOEPD for the three and six months ended June 30,

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2014, and 3,073 BOEPD and 3,192 BOEPD for the corresponding periods in 2013. Argentina production for the three and six months ended June 30, 2014, was calculated to the date of sale of June 25, 2014.

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

Net income for the three and six months ended June 30, 2014, was $9.1 million and $54.3 million, respectively, compared with $47.8 million and $105.7 million in the comparable periods in 2013. On a per share basis, net income decreased to $0.03 per share basic and diluted for the three months ended June 30, 2014, from $0.17 per share basic and diluted in the corresponding period in 2013. For the six months ended June 30, 2014, net income decreased to $0.19 per share basic and diluted from $0.37 per share basic and diluted in the corresponding period in 2013. For the three and six months ended June 30, 2014, the decrease was due to lower income from continuing operations and higher loss from discontinued operations, net of income taxes.

Income from continuing operations was $31.5 million, or $0.11 per share basic and diluted, and $81.3 million, or $0.29 per share basic and $0.28 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with $49.6 million and $109.6 million, or $0.18 per share basic and diluted, and $0.38 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three months ended June 30, 2014, decreased oil and natural gas sales, and higher operating, G&A and income tax expenses and foreign exchange losses, were only partially offset by decreased DD&A expenses and financial instruments gains. For the six months ended June 30, 2014, decreased oil and natural gas sales, increased G&A expenses and foreign exchange losses were only partially offset by lower operating, DD&A and income tax expenses, financial instruments gains and the absence of other loss.

Loss from discontinued operations, net of income taxes, was $22.3 million, or $0.08 per share basic and diluted, and $27.0 million, or $0.10 per share basic and $0.09 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with $1.8 million and $3.9 million, respectively, or $0.01 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three and six months ended June 30, 2014, loss from discontinued operations, net of tax, included loss on disposal of the Argentina business unit of $19.3 million.

Oil and NGL production NAR before inventory adjustments and losses for the three and six months ended June 30, 2014, increased to 19,619 and 19,266 bopd compared with 19,356 and 18,995 bopd in the corresponding periods in 2013, respectively. In 2014, production from new wells in the Moqueta field in the Chaza Block and new wells in the Llanos-22 Block and fewer days of pipeline disruptions had a positive effect on production NAR before inventory adjustments and losses in Colombia.

Oil and NGL production NAR after inventory adjustments and losses for the three and six months ended June 30, 2014, decreased by 9% to 17,286 bopd and by 8% to 17,956 bopd compared with the corresponding periods in 2013, respectively. The decrease in production was primarily due to an increase in oil inventory in the Ecopetrol S.A. ("Ecopetrol") operated Trans-Andean oil pipeline (the "OTA pipeline”) and associated Ecopetrol owned facilities and in our crude oil storage tanks in the Putumayo Basin as a result of pipeline disruptions, and deliveries to a customer with a protracted sales cycle whereby the transfer of ownership will not occur until oil is exported. During the six months ended June 30, 2014, a net inventory increase accounted for 0.2 MMbbl or 1,310 bopd of reduced production compared with a net inventory reduction in 2013 which accounted for 0.1 MMbbl or 578 bopd increased production. The oil inventory reduction in 2013 was due to a decrease in oil inventory in the OTA pipeline and associated Ecopetrol owned facilities in the Putumayo Basin and reduced oil inventory related to sales to a customer in Colombia with a protracted sales cycle whereby the transfer of ownership occurred upon export. In the three and six months ended June 30, 2014 and 2013, the impact of OTA pipeline disruptions on production was partially mitigated by selling a portion of our oil through trucking and an alternative pipeline.

Average realized oil prices increased by 8% to $93.72 per bbl for the three months ended June 30, 2014, from $86.71 per bbl in the comparable period in 2013 and decreased by 3% to $91.74 per bbl for the six months ended June 30, 2014, from $94.99 per bbl in the comparable period in 2013. Average Brent oil prices for the three and six months ended June 30, 2014, were $109.70 and $108.93 per bbl, respectively, compared with $102.58 and $107.54 per bbl in the corresponding periods in 2013. Average WTI oil prices for the three and six months ended June 30, 2014, were $102.99 and $100.84 per bbl, respectively, compared with $94.22 and $94.31 per bbl in the corresponding periods in 2013. During the three and six months ended June 30, 2014, 39% and 43% of our oil and gas volumes sold in Colombia, respectively, were to a customer which takes delivery at the Costayaco battery and transports the oil by truck over a 1,500 km route to the Port of Barranquilla. The sales price for this customer is based on average WTI prices plus a Vasconia differential and premium, less trucking costs. For sales to this customer, the trucking costs are recorded as a reduction of the realized price and not as operating costs. Sales to this customer during the corresponding periods in 2013 were 51% and 40% of our oil and gas volumes sold in Colombia

Revenue and other income for the three months ended June 30, 2014, decreased to $148.5 million from $150.6 million in the comparable period in 2013 as a result of decreased production primarily due to increased oil inventory, partially offset by increased realized prices. Revenue and other income for the six months ended June 30, 2014, decreased to $300.4 million from $337.2 million in the comparable period in 2013. due to higher inventory levels as well as lower realized prices.

Operating expenses increased by 6% to $25.3 million and decreased by 16% to $47.2 million for the three and six months ended June 30, 2014, respectively, from the comparable periods in 2013. For the three months ended June 30, 2014, the increase in operating expenses was primarily due to an increase in the operating cost per BOE, partially offset by decreased production. For the six months ended June 30, 2014, the decrease in operating expenses was due to a decrease in the operating cost per BOE combined with decreased production.

On a per BOE basis, operating expenses increased by 15% to $15.89 and decreased by 9% to $14.38 for the three and six months ended June 30, 2014, respectively, from $13.82 and $15.80 in the comparable periods in 2013. Operating expenses per BOE increased in the three months ended June 30, 2014, due to an increase in transportation costs as a result of lower volumes subject to alternative transportation arrangements, for which trucking costs related to a 1,500 km route are paid by the purchaser and netted to arrive at our realized price rather than recorded as transportation expenses. The decrease in operating costs per BOE in the six months ended June 30, 2014, was due to inventory volumes liquidated in the comparative period in 2013 which had high transportation costs due to the delivery point to which they were sold and to which we did not deliver in the current period. Operating expenses per BOE also decreased in the six months ended June 30, 2014 as a result of deferred workover expenses, lower fuel consumption and lower training costs.

DD&A expenses for the three months ended June 30, 2014, decreased to $41.9 million from $55.6 million in the comparable period in 2013, due to lower production and a decreased depletion rate. On a per BOE basis, the depletion rate decreased by 18% to $26.30 from $32.06. DD&A expenses for the three months ended June 30, 2013, included a $2.0 million ceiling test impairment loss in our Brazil cost center. On a per BOE basis, in addition to the 2013 impairment charge, the decrease was due to an increase in reserves and a decrease in costs in the depletable base relating to lower future development costs and the receipt of a termination payment in Brazil in the third quarter of 2013 which reduced the cost base. DD&A expenses for the six months ended June 30, 2014, decreased to $86.2 million ($26.26 per BOE) from $106.1 million ($29.92 per BOE) in the comparable period in 2013, due to lower production and a decreased depletion rate.

G&A expenses for the three months ended June 30, 2014, increased by 53% to $13.9 million ($8.74 per BOE) from $9.1 million ($5.24 per BOE) compared with the corresponding period in 2013. Increased employee related costs, higher consulting expenses associated with increased activity, expanded operations in Peru and higher bank fees, were only partially offset by higher G&A allocations to capital projects within the business units. During the three months ended June 30, 2013, we received $1.0 million from the U.S. Federal Government for assets recovered from our former U.S. securities counsel as compensation for damages suffered in 2006. This amount was recorded as a reduction of G&A expenses in the corresponding period in 2013.

G&A expenses for the six months ended June 30, 2014, increased by 48% to $26.8 million ($8.16 per BOE) from $18.1 million ($5.11 per BOE), the corresponding period in 2013. The increase was primarily due to increased employee related costs, higher consulting expenses associated with increased activity, expanded operations in Peru and higher stock-based compensation expense associated with restricted stock units ("RSUs") and stock options. These increases were partially offset by higher G&A allocations to capital projects within the business units.

For the three and six months ended June 30, 2014, the foreign exchange loss was $10.0 million and $5.8 million, respectively. For the three months ended June 30, 2014, we had realized foreign exchange losses of $1.3 million and an unrealized non-cash foreign exchange loss of $8.7 million. For the six months ended June 30, 2014, we had realized foreign exchange losses of $1.2 million and an unrealized non-cash foreign exchange loss of $4.6 million. Foreign exchange losses and gains are primarily a result of a net monetary liability position in Colombia and the strengthening of Colombian Peso versus U.S. dollar..

For the three months ended June 30, 2013, there was a foreign exchange gain of $12.6 million, comprising an $11.6 million unrealized non-cash foreign exchange gain and realized foreign exchange gains of $1.0 million. For the six months ended June 30, 2013, there was a foreign exchange gain of $19.0 million, comprising an $18.4 million unrealized non-cash foreign exchange gain and realized foreign exchange gains of $0.6 million. The unrealized non-cash foreign exchange gain was a result of a net monetary liability position in Colombia and the weakening of Colombian Peso versus U.S, dollar.

Financial instruments gain of $2.6 million and $5.0 million in the three and six months ended June 30, 2014, respectively, included a realized financial instrument gain of $4.7 million. For the three months ended June 30, 2014, the realized financial instrument gain was partially offset by unrealized financial instruments losses of $2.1 million. In the six months ended June 30, 2014, we had unrealized financial instruments gains of $351 thousand.

The gains and losses primarily related our Colombian peso non-deliverable forward contracts. We purchased these contracts for purposes of fixing the exchange rate at which we will purchase Colombian pesos to settle our income tax installment payments. Financial instruments gain in the three and six months ended June 30, 2014, also included a $0.3 million unrealized gain on the Madalena shares. We received these shares in connection with the sale of our Argentina business unit. Madalena is an independent, Canadian-based, domestic and international upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Madalena's shares are listed on the Canadian TSX Venture Exchange.

Other loss of $4.4 million in the six months ended June 30, 2013, related to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment in the first quarter of 2013. We have filed an appeal against the judgment.

Income tax expense related to continuing operations was $28.4 million and $58.1 million for the three and six months ended June 30, 2014, respectively, compared with $25.0 million and $62.0 million in the comparable periods in 2013. The decrease for the six months ended June 30, 2014, was primarily due to lower taxable income in Colombia. The effective tax rate was 42% in the six months ended June 30, 2014, compared with 36% in the comparable period in 2013. The change in the effective tax rate was primarily due to an increase in non-deductible foreign currency translation adjustments and other permanent differences, partially offset by a decrease in the valuation allowance.

For the six months ended June 30, 2014, the differential between the effective tax rate of 42% and the 35% U.S. statutory rate was primarily attributable to a non-deductible third party royalty in Colombia, the impact of other local taxes, non-deductible stock-based compensation, and other permanent differences which were partially offset by the deductible foreign tax rate differential. The variance from the 35% U.S. statutory rate for 2013 was primarily attributable to a non-deductible third party royalty in Colombia, an increase in valuation allowance and non-deductible stock-based compensation, which was partially offset by a decrease in non-deductible foreign currency translation adjustments, the foreign tax rate differential and other permanent adjustments.

2014 Work Program and Capital Expenditure Program

Our 2014 capital program has been revised to $482 million from $495 million. This includes: $249 million for Colombia; $173 million for Peru; $37 million for Brazil; $18 million for Argentina; and $5 million associated with corporate activities. The decrease in our capital spending is primarily due to the sale of the Argentina business unit. The capital spending program allocates $278 million for drilling; $77 million for facilities, pipelines and other; $122 million for G&G expenditures; and $5 million for corporate activities. Of the $278 million allocated to drilling, approximately 20% is for exploration and the balance is for appraisal and development drilling.

Our 2014 work program is intended to create both growth and value by developing existing assets to increase reserves and
production levels, the construction of pipelines and facilities in the areas with proved reserves, and maturing our exploration prospects through seismic acquisition and drilling. We expect to finance our 2014 capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds be expended as set forth in our 2014 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Segmented Results from Continuing Operations – Colombia

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$139,350	$144,333	(3)	$284,285	$324,336	(12)
Interest income	184	143	29	321	304	6
	139,534	144,476	(3)	284,606	324,640	(12)
Operating expenses	23,281	22,349	4	43,486	52,301	(17)
DD&A expenses	39,348	48,364	(19)	80,598	94,320	(15)
G&A expenses	5,798	3,379	72	10,181	8,015	27
Foreign exchange loss (gain)	10,891	(14,086)	177	6,523	(20,534)	(132)
Financial instruments gain	(2,265)	—	—	(4,674)	—	—
Other loss	—	—	—	—	4,400	(100)
	77,053	60,006	28	136,114	138,502	(2)
Income from continuing operations before income taxes	$62,481	$84,470	(26)	$148,492	$186,138	(20)
Production (1)						
Oil and NGL's, bbl	1,483,854	1,665,555	(11)	3,094,509	3,411,881	(9)
Natural gas, Mcf	129,711	10,468	—	194,490	10,468	—
Total production, BOE	1,505,473	1,667,300	(10)	3,126,924	3,413,626	(8)
Average Prices						
Oil and NGL's per bbl	$93.56	$86.61	8	$91.57	$95.04	(4)
Natural gas per Mcf	$4.01	$7.18	(44)	$4.79	$7.18	(33)
Segmented Results of Operations per BOE						
Oil and natural gas sales	$92.56	$86.57	7	$90.92	$95.01	(4)
Interest income	0.12	0.09	33	0.10	0.09	11
	92.68	86.66	7	91.02	95.10	(4)
Operating expenses	15.46	13.40	15	13.91	15.32	(9)
DD&A expenses	26.14	29.01	(10)	25.78	27.63	(7)
G&A expenses	3.85	2.03	90	3.26	2.35	39
Foreign exchange loss (gain)	7.23	(8.45)	186	2.09	(6.02)	(135)
Financial instruments gain	(1.50)	—	—	(1.49)	—	—
Other loss	—	—	—	—	1.29	(100)
	51.18	35.99	42	43.55	40.57	7
Income from continuing operations before income taxes	$41.50	$50.67	(18)	$47.47	$54.53	(13)

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

For the three and six months ended June 30, 2014, income from continuing operations before income taxes was $62.5 million and $148.5 million, respectively, compared with $84.5 million and $186.1 million in the comparable periods in 2013. For the three months ended June 30, 2014, the decrease was due to lower oil and natural gas sales as a result of lower production after inventory adjustments and increased operating and G&A expenses and foreign exchange losses, partially offset by decreased DD&A expenses and financial instrument gains. For the six months ended June 30, 2014, the decrease was due to lower oil and natural gas sales as a result of lower production after inventory adjustments, higher G&A expenses and foreign exchange losses, partially offset by decreased operating and DD&A expenses, financial instrument gains and the absence of other losses.

Oil and NGL production NAR before inventory adjustments and losses for the three and six months ended June 30, 2014, increased to 18,626 bopd and 18,390 bopd compared with 18,510 bopd and 18,182 bopd, respectively, in the corresponding periods in 2013. In 2014, production from new wells in the Moqueta field in the Chaza Block and new wells in the Llano-22 Block and a reduction of 23 days in the number of days of pipeline disruptions had a positive effect on production NAR before inventory adjustments and losses. Production during the six months ended June 30, 2014, reflected approximately 92 days of oil delivery restrictions in Colombia compared with 115 days of oil delivery restrictions in the comparable period in 2013.

Oil and NGL production NAR after inventory adjustments and losses for the three and six months ended June 30, 2014, decreased to 1.5 MMbbl or 16,306 bopd and 3.1 MMbbl or 17,097 bopd compared with 1.7 MMbbl or 18,303 bopd and 3.4 MMbbl or 18,850 bopd, respectively, in the comparable periods in 2013. During the three and six months ended June 30, 2014, an oil inventory increase accounted for reduced production of 0.2 MMbbl or 2,320 bopd and 0.2 MMbbl or 1,293 bopd, respectively, compared with a net inventory reduction in the six months ended June 30, 2013, which accounted for 0.1 MMbbl or 669 bopd increased production during that period. In 2014, oil inventory in the OTA pipeline and associated Ecopetrol owned facilities as well as our tanks in the Putumayo Basin increased as a result of pipeline disruptions and we made deliveries to a customer with a protracted sales cycle whereby the transfer of ownership will not occur until export, which also increased inventory. The oil inventory reduction in 2013 was due to a decrease in oil inventory in the OTA pipeline and associated Ecopetrol owned facilities in the Putumayo Basin and reduced oil inventory related to sales to a customer in Colombia with a protracted sales cycle whereby the transfer of ownership occurred upon export.

Revenue and other income for the three and six months ended June 30, 2014, decreased by 3% to $139.5 million and 12% to $284.6 million, respectively, from the comparable periods in 2013.

For the three months ended June 30, 2014, the average realized price per bbl for oil increased by 8% to $93.56 compared with $86.61 in the corresponding period in 2013. For the six months ended June 30, 2014, the average realized price per bbl for oil decreased by 4% to $91.57 compared with $95.04 in the corresponding period in 2013. Average Brent oil prices for the three and six months ended June 30, 2014, were $109.70 and $108.93 per bbl, respectively, compared with $102.58 and $107.54 per bbl in the corresponding periods in 2013.

During the three and six months ended June 30, 2014, 39% and 43% of our oil and gas volumes sold, respectively, were to a customer to which oil is delivered at the Costayaco battery and the sales price is based on average WTI prices plus a Vasconia differential and premium, adjusted for trucking costs related to a 1,500 km route. The effect on the Colombian realized price for the three and six months ended June 30, 2014, was a reduction of approximately $6.94 and $7.87 per BOE, respectively, as compared with delivering all of our Colombian oil through the OTA pipeline. Sales to this customer during the corresponding periods in 2013 were 51% and 40%, respectively, of our oil and gas volumes sold in Colombia and the effect on the Colombian realized price was a reduction of approximately $11.30 and $9.85 per BOE, respectively.

Operating expenses increased by 4% to $23.3 million for the three months ended June 30, 2014, and decreased by 17% to $43.5 million for the six months ended June 30, 2014, from the comparable periods in 2013. For the three months ended June 30, 2014, the effect of lower production was more than offset by an increase in operating costs per BOE, whereas for the six months ended June 30, 2014, the effect of lower production combined with decreased operating cost per BOE. On a per BOE basis, operating expenses increased by 15% to $15.46 for the three months ended June 30, 2014, and decreased by 9% to $13.91 for the six months ended June 30, 2014, from $13.40 and $15.32, respectively, in the comparable periods in 2013. In the three months ended June 30, 2014, operating expenses per BOE increased primarily due to higher pipeline charges and trucking costs recorded as operating costs due to a higher portion of sales being made to Ecopetrol in the period. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the three months ended June 30, 2014, was a saving of $1.33 per BOE compared with a saving of $2.20 per BOE in the corresponding period in 2013.

In the six months ended June 30, 2014, operating expenses per BOE decreased primarily due to higher transportation costs associated with the liquidated inventory volumes in the comparative period of 2013. The inventory volumes liquidated in the comparative six months ended June 30, 2013, were primarily related to a delivery point which carried high transportation costs, and to which we did not deliver in the current period. Transportation costs were also lower due to a reduction in pipeline charges and trucking costs resulting from increased volumes sold to a customer who takes delivery at the Costayaco battery as previously discussed. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the six months ended June 30, 2014, was a saving of $1.52 per BOE.

DD&A expenses decreased by 19% to $39.3 million and 15% to $80.6 million for the three and six months ended June 30, 2014, respectively, from the comparable periods in 2013. The decrease was due to decreased production and a decrease in the per BOE depletion rate. On a per BOE basis, DD&A expenses decreased by 10% to $26.14 and 7% to $25.78 for the three and six months ended June 30, 2014, respectively. The decrease was primarily due to an increase in reserves, partially offset by increased costs in the depletable base.

G&A expenses increased by 72% to $5.8 million ($3.85 per BOE) from $3.4 million ($2.03 per BOE) and by 27% to $10.2 million ($3.26 per BOE) from $8.0 million ($2.35 per BOE) for the three and six months ended June 30, 2014, respectively, from the comparable periods in 2013. The increases were primarily due to increased salaries expense due to increased headcount and increased consulting fees. Additionally, bank fees increased in the three months ended June 30, 2014, as a result of income tax payments.

For the three months ended June 30, 2014, the foreign exchange loss was $10.9 million, which included an $8.7 million unrealized non-cash foreign exchange loss. In the three months ended June 30, 2013, we had a foreign exchange gain of $14.1 million, which included an $11.6 million unrealized non-cash foreign exchange gain. The Colombian Peso strengthened by 4% and weakened by 5% against the U.S. dollar in the three months ended June 30, 2014, and 2013, respectively. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation is the main source of the unrealized foreign exchange losses or gains.

For the six months ended June 30, 2014, the foreign exchange loss was $6.5 million, which included a $4.6 million unrealized non-cash foreign exchange loss. In the six months ended June 30, 2013, we incurred a foreign exchange gain of $20.5 million, of which $18.4 million was an unrealized non-cash foreign exchange gain. The Colombian Peso strengthened by 2% and weakened by 9% against the U.S. dollar in the six months ended June 30, 2014, and 2013, respectively.

Financial instruments gain of $2.3 million and $4.7 million in the three and six months ended June 30, 2014, related to gains on our Colombian peso non-deliverable forward contracts, of which $4.7 million was realized during the three and six months ended June 30, 2014. We purchased these contracts for purposes of fixing the exchange rate at which we purchase Colombian pesos to settle our income tax installment payments.

Other loss of $4.4 million in the six months ended June 30, 2013, related to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment within the quarter. We have filed an appeal against the judgment.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the three months ended June 30, 2014, were $45.7 million bringing total capital expenditures for the six months ended June 30, 2014, to $96.2 million. During the second quarter of 2013, we received proceeds of $1.5 million from the sale of our 15% working interest in the Mecaya Block in Colombia. The following table provides a breakdown of capital expenditures in 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of U.S. Dollars)	2014	2013	2014	2013
Drilling and completions	$25.7	$24.8	$56.3	$39.7

G&G	8.8	11.3	19.9	16.6
Facilities and equipment	7.3	10.5	13.5	16.7
Other	3.9	3.6	6.5	7.7
	$45.7	$50.2	$96.2	$80.7

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

- On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Moqueta-13 development well in the Moqueta field and drilled and started completion work on the Costayaco-21 development well in the Costayaco field. The Costayaco-20 and Costayaco-22 development wells began production as oil producers. The

Zapotero-1 exploration well reached a total true vertical depth of 7,549 feet. Production testing of the Zapotero-1 exploration well indicated the presence of water in the Villeta T and U Sandstones, and in the Caballos formation.

- We acquired 3-D seismic on the Putumayo-1 Block (55% WI, operated) and 2-D seismic on the Piedemonte Sur Block (100% WI, operated) and Cauca-7 Block (100% WI, operated) and completed an aerogravity and magnetic survey on the Sinu-1 (60% WI, operated) and Sinu-3 Blocks (51% WI, operated). We continued work in preparation for a future seismic program on the Sinu-1 and Sinu-3 Blocks and completed regional field studies and continued work to obtain the necessary environmental and social permits for future seismic programs on the Chaza Block.
- We also continued facilities work at the Costayaco and Moqueta fields on the Chaza Block and the Llanos-22 Block (45% WI, non-operated).

Subsequent to the second quarter 2014, we were the successful bidder on the Putumayo-31 Block in the Putumayo Basin of Colombia in Colombia's National Hydrocarbon Agency ("ANH") 2014 Bid Round and are expected to become operator of this block, subject to final ANH approval.

Outlook - Colombia

The 2014 capital program in Colombia is $249 million with $133 million allocated to drilling, $51 million to facilities and pipelines and $65 million for G&G expenditures.

Our planned work program for the remainder of 2014 in Colombia includes drilling three oil exploration wells on the Chaza Block and one gross exploration well on the Putumayo-1 Block. We also plan to drill an additional four development wells on the Chaza Block (both Costayaco and Moqueta fields).

We also plan to acquire 2-D seismic on the Chaza, Guayuyaco (70% WI, operated), Sinu-1 and Sinu-3 Blocks and Cauca-6 and 7 Blocks and continue interpretation of 3-D seismic acquired on the Putumayo-1 Block. Facilities work is also planned for the Chaza, Garibay (50% WI, non-operated) and Llanos-22 Blocks.

Segmented Results from Continuing Operations – Peru

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
(Thousands of U.S. Dollars)						
Interest income	$—	$12	(100)	$—	$26	(100)
DD&A expenses	103	137	(25)	311	199	56
G&A expenses	2,329	1,381	69	3,971	2,387	66
Foreign exchange (gain) loss	(24)	847	(103)	184	1,020	82
	2,408	2,365	2	4,466	3,606	24
Loss from continuing operations before income taxes	$(2,408)	$(2,353)	2	$(4,466)	$(3,580)	25

For the three and six months ended June 30, 2014, loss from continuing operations before income taxes in Peru was $2.4 million and $4.5 million, respectively, compared with $2.4 million and $3.6 million in the comparable periods in 2013. In the three and six months ended June 30, 2014, increased G&A expenses were partially offset by the lower foreign exchange losses. The increase in G&A expenses was due to higher salaries expense as a result of an increased headcount and higher consulting fees due to expanded operations, partially offset by increased G&A allocations to capital projects.

Capital Program – Peru

Capital expenditures in the three months ended June 30, 2014, were $41.9 million bringing total capital expenditures for the six months ended June 30, 2014, to $62.8 million. Capital expenditures in the three months ended June 30, 2014 consisted of drilling of $31.5 million, G&G expenditures of $3.5 million, facilities expenditures of $0.7 million and, asset retirement obligation and other asset expenditures of $6.2 million.

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

- On Block 95 (100% WI, operated), we drilled the Bretaña-1WD water disposal well on the Bretaña field, started engineering, procurement and construction work in preparation for long-term production test and purchased long-lead items for future drilling activities on this field.
- On Block 107 and Block 133 (both 100% WI, operated), we continued work to obtain the necessary environmental and social permits for future seismic programs. We also continued the refurbishment of a seismic camp on Block 107.

Outlook - Peru

The 2014 capital program in Peru is $173 million with $116 million allocated to drilling, $18 million for facilities and $39 million for G&G expenditures.

Our planned work program for the remainder of 2014 includes drilling an appraisal well in the Bretaña field and the completion of crude oil processing and loading facilities in order to initiate a long-term production test in the fourth quarter of 2014. Additionally, we expect to acquire 2-D seismic on Block 107, continue work to obtain the necessary environmental and social permits in anticipation of drilling our first exploration wells on Blocks 123, 129 and 107 in future years and continue work to obtain the necessary environmental and social permits for planned seismic programs on Blocks 133.

Segmented Results from Continuing Operations – Brazil

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
(Thousands of U.S. Dollars)						
Oil sales	$8,538	$5,917	44	$14,708	$12,154	21
Interest income	434	2	—	859	11	—
	8,972	5,919	52	15,567	12,165	28
Operating expenses	2,066	1,621	27	3,726	3,712	—
DD&A expenses	2,241	6,843	(67)	4,820	11,014	(56)
G&A expenses	1,424	317	349	2,075	743	179
Foreign exchange (gain) loss	(509)	25	—	(754)	22	—
	5,222	8,806	(41)	9,867	15,491	(36)
Income (loss) from continuing operations before income taxes	$3,750	$(2,887)	(230)	$5,700	$(3,326)	(271)
Production (1)						
Oil and NGL's, bbl	89,217	66,959	33	155,540	130,793	19
Average Prices						
Oil and NGL's per bbl	$95.70	$88.37	8	$94.56	$92.93	2
Segmented Results of Operations per bbl						
Oil sales	$95.70	$88.37	8	$94.56	$92.93	2
Interest income	4.86	0.03	—	5.52	0.08	—
	100.56	88.40	14	100.08	93.01	8
Operating expenses	23.16	24.21	(4)	23.96	28.38	(16)
DD&A expenses	25.12	102.20	(75)	30.99	84.21	(63)
G&A expenses	15.96	4.73	237	13.34	5.68	135
Foreign exchange (gain) loss	(5.71)	0.37	—	(4.85)	0.17	—
	58.53	131.51	(55)	63.44	118.44	(46)
Income (loss) from continuing operations before income taxes	$42.03	$(43.11)	(197)	$36.64	$(25.43)	(244)

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

For the three and six months ended June 30, 2014, income from continuing operations before income taxes was $3.8 million and $5.7 million compared with loss from continuing operations before income taxes of $2.9 million and $3.3 million in the comparable periods in 2013. Income from continuing operations before income taxes resulted from increased oil and natural gas sales, decreased DD&A expenses and increased foreign exchange gains, partially offset by increased operating and G&A expenses. In the second quarter of 2013, we recorded a ceiling test impairment loss of $2.0 million due to lower realized prices and an increase in estimated operating costs.

Oil and NGL production in Brazil is from the Tiê field in Block 155 in the onshore Recôncavo Basin. Oil and NGL production for the three and six months ended June 30, 2014, increased to 89.2 Mbbl or 980 bopd and 155.5 Mbbl or 859 bopd compared with 67.0 Mbbl or 736 bopd and 130.8 Mbbl or 723 bopd, respectively, in the comparable periods in 2013. Production increased primarily as a result of the successful dual completion of the 4-GTE-04-BA well, which was partially offset by the impact of well downtime for workovers, and the dual completion of the 3-GTE-03-BA well. Our production in Brazil continues to be limited due to gas flaring restrictions and we are continuing to evaluate options to mitigate the effect of these restrictions.

Revenue and other income increased to $9.0 million and $15.6 million, respectively, for the three and six months ended June 30, 2014, compared with $5.9 million and $12.2 million in the comparable periods in 2013. The increase was due to higher production levels and increased average realized price. For the three and six months ended June 30, 2014, the average realized price per bbl for oil increased by 8% to $95.70 and by 2% to $94.56, respectively. Average Brent oil price for the three and six months ended June 30, 2014, was $109.70 and $108.93 per bbl, compared with $102.58 and $107.54 per bbl in the corresponding periods in 2013. The price we receive in Brazil is at a discount to Brent due to refining and quality discounts.

Operating expenses increased to $2.1 million and $3.7 million, respectively, for the three and six months ended June 30, 2014, compared with $1.6 million and $3.7 million in the comparable periods in 2013. On a per bbl basis, operating expenses decreased to $23.16 and $23.96 for the three and six months ended June 30, 2014, respectively, from $24.21 per bbl and $28.38 per bbl in the corresponding periods in 2013, respectively. Operating expenses per bbl decreased due to lower water disposal and slickline services costs, partially offset by increased workover expenses due to increased workover activity.

DD&A expenses were $2.2 million ($25.12 per bbl) and $4.8 million ($30.99 per bbl) in the three and six months ended June 30, 2014, respectively, compared with $6.8 million ($102.20 per bbl) and $11.0 million ($84.21 per bbl) in the comparable periods in 2013. In the second quarter of 2013, we recorded a ceiling test impairment loss of $2.0 million, as discussed earlier. On a per bbl basis, in addition to the 2013 impairment charge, the decrease was due to an increase in reserves and a decrease in costs in the depletable base relating to lower future development costs and the receipt of a termination payment relating to a former joint venture in the third quarter of 2013 that reduced the cost base.

G&A expenses were $1.4 million ($15.96 per bbl) and $2.1 million ($13.34 per bbl) in the three and six months ended June 30, 2014, respectively, compared with $0.3 million ($4.73 per bbl) and $0.7 million ($5.68 per bbl) in the comparable periods in 2013. The increase in G&A expenses was primarily due to lower G&A allocations to capital projects within the business unit as a result of lower capital activity in 2014.

Capital Program – Brazil

Capital expenditures in the three months ended June 30, 2014, were $3.4 million bringing total capital expenditures for the six months ended June 30, 2014, to $13.8 million. Capital expenditures in the three months ended June 30, 2014 included drilling of $2.9 million, G&G expenditures of $0.1 million, and other expenditures of $0.4 million.

The significant elements of our second quarter 2014 capital program in Brazil were:

- On Block REC-T-155 (100% WI, operated), we successfully completed the dual completion of the 3-GTE-03-BA development well and continued to evaluate alternatives for the 1-GTE-07-BA exploration well.

Outlook – Brazil

The 2014 capital program in Brazil is $37 million with $14 million allocated to drilling, $6 million to facilities and pipelines and $17 million for G&G and other expenditures.

Our planned work program for the remainder of 2014 in Brazil will focus on facilities work in the Tiê field along with seismic acquisition on Block REC-T-86, Block REC-T-117 and Block REC-T-118. We will continue the study of two unconventional resource plays in 2014 through core analysis, geochemistry studies, 3-D seismic acquisition and re-processing and evaluating ongoing fracture stimulation test results, among other activities in an effort to establish the commercial viability of the resource opportunity in oil-saturated tight sandstones and shales in the Recôncavo Basin.

Results from Continuing Operations - Corporate Activities

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013 (1)	% Change	2014 (1)	2013 (1)	% Change
(Thousands of U.S. Dollars)						
Interest income	$20	$167	(88)	$208	$330	(37)
DD&A expenses	245	248	(1)	472	521	(9)
G&A expenses	4,381	4,012	9	10,568	6,967	52
Foreign exchange (gain) loss	(315)	593	(153)	(119)	513	(123)
Financial instruments gain	(339)	—	—	(339)	—	—
	3,972	4,853	(18)	10,582	8,001	32
Loss from continuing operations before income taxes	$(3,952)	$(4,686)	(16)	$(10,374)	$(7,671)	35

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

G&A expenses in the three and six months ended June 30, 2014, were $4.4 million and $10.6 million, respectively, compared with $4.0 million and $7.0 million in the comparable periods in 2013. During the three months ended June 30, 2013, we received $1.0 million from the U.S. Federal Government for assets recovered from our former U/S. securities counsel as compensation for damages suffered in 2006. This amount was recorded as a reduction of G&A expenses in the corresponding period in 2013.

For the six months ended June 30, 2014, the increase in G&A expenses was primarily due to higher salaries, higher consulting expenses associated with increased activity and higher stock-based compensation expense associated with RSUs and stock options granted. The annual grant to employees was not made until May 2013 in the prior year, therefore, no expense was recorded relating to the annual grant in the three months ended March 31, 2013 reducing stock-based compensation expense for the six months ended June 30, 2013.

Results from Discontinued Operations

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

Loss from discontinued operations, net of income taxes was $22.3 million and $27.0 million for the periods ended June 25, 2014, respectively, compared with $1.8 million and $3.9 million, respectively, in the corresponding periods in 2013. For the three months ended June 30, 2014, loss from discontinued operations, net of tax, included loss on disposal of $19.3 million and loss from operations after income taxes of $3.1 million.

The following table presents results from discontinued operations before income taxes and loss on sale for the three and six months ended June 30, 2014, and the corresponding periods in 2013. Results from discontinued operations before income taxes for the three and six months ended June 30, 2014, was calculated to the date of sale of June 25, 2014.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014 (1)	2013 (1) (2)	% Change	2014 (1)	2013 (1) (2)	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$14,518	$17,931	(19)	$31,938	$36,470	(12)
Interest income	(357)	303	(218)	47	550	(91)
	14,161	18,234	(22)	31,985	37,020	(14)
Operating expenses	8,184	7,932	3	14,612	16,904	(14)
DD&A expenses	4,790	7,430	(36)	13,684	15,380	(11)
G&A expenses	3,239	2,656	22	5,579	5,055	10
Foreign exchange loss	27	640	(96)	4,362	1,770	146
	16,240	18,658	(13)	38,237	39,109	(2)
Loss from operations of discontinued operations before income taxes	$(2,079)	$(424)	390	$(6,252)	$(2,089)	199
Production (3)						
Oil and NGL's, bbl	172,602	228,382	(24)	377,795	470,959	(20)
Natural gas, Mcf	289,006	307,603	(6)	713,262	640,216	11
Total production, BOE	220,770	279,649	(21)	496,672	577,662	(14)
Average Prices						
Oil and NGL's per bbl	$75.23	$72.32	4	$75.98	$71.80	6
Natural gas per Mcf	$5.31	$4.60	15	$4.53	$4.15	9
Segmented Results of Operations per BOE						
Oil and natural gas sales	$65.76	$64.12	3	$64.30	$63.13	2
Interest income	(1.62)	1.08	(250)	0.09	0.95	(91)
	64.14	65.20	(2)	64.39	64.08	—
Operating expenses	37.07	28.36	31	29.42	29.26	1
DD&A expenses	21.70	26.57	(18)	27.55	26.62	3
G&A expenses	14.67	9.50	54	11.23	8.75	28
Foreign exchange loss	0.12	2.29	(95)	8.78	3.06	187
	73.56	66.72	10	76.98	67.69	14
Loss from operations of discontinued operations before income taxes	$(9.42)	$(1.52)	520	$(12.59)	$(3.61)	249

(1) Results from discontinued operations before income taxes for the three and six months ended June 30, 2014, was calculated to the date of sale of June 25, 2014.

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

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

For the three months ended June 30, 2014, loss from operations of discontinued operations before income taxes was $2.1 million compared with $0.4 million in the three months ended June 30, 2013. For the six months ended June 30, 2014, loss from operations of discontinued operations before income taxes was $6.3 million, compared with $2.1 million in the six months ended June 30, 2013. In the three months ended June 30, 2014, decreased oil and natural gas sales and increased operating and G&A expenses were partially offset by decreased DD&A expenses. In the six months ended June 30, 2014, decreased oil and natural gas sales and increased G&A expenses and foreign exchange losses were partially offset by decreased operating and DD&A expenses.

Total oil and gas production from Argentina decreased by 21% to 0.2 MMBOE for the three months ended June 30, 2014, and by 14% to 0.5 MMBOE for the six months ended June 30, 2014, compared with the corresponding periods in 2013.

Oil and NGL production decreased by 24% to 0.2 MMbbl or 1,897 bopd for the three months ended June 30, 2014, and decreased by 20% to 0.4 MMbbl or 2,087 bopd for the six months ended June 30, 2014, compared with the three and six months ended June 30, 2013. The decreases were primarily due to reduced production from the Puesto Morales and Surubi Blocks due to delays in securing workover rigs, expected production declines, the conversion of an oil producing well to a gas producer and because the business was sold prior to June 30, 2014, partially offset by higher production from the El Vinalar Block due to an increase in our working interest in this block from 50% to 100% and successful workovers on wells in the block. We acquired our partner's 50% working interest in the El Vinalar Block in November 2013.

In addition to the decrease in oil and NGL production, gas production decreased by 6% and increased by 11% for the three and six months ended June 30, 2014, respectively, compared with the three and six months ended June 30, 2013, respectively.

Revenue and other income decreased by 22% to $14.2 million and by 14% to $32.0 million for the three and six months ended June 30, 2014, respectively. The decrease was due to lower production, partially offset by higher realized prices. Revenue for the six months ended June 30, 2014, included $1.8 million from the sale of our remaining Petroleum Plus program credits in the first quarter of 2014. These credits are granted by the Argentina government to companies for new production of oil or natural gas, either from new discoveries, enhanced recovery techniques or reactivation of older fields.

For the three and six months ended June 30, 2014, the average realized price per bbl for oil increased by 4% to $75.23 and by 6% to $75.98, respectively, compared with $72.32 and $71.80, in the three and six months ended June 30, 2013. The impact of the sale of our Petroleum Plus program credits in the six months ended June 30, 2014 was $4.75 per bbl. The prices we received in Argentina are influenced by the Argentina regulatory regime. Currently, most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. During January to April 2014, the Argentine government imposed oil price discounts in the range of 3.75% to 14% through fixing the monthly exchange rate at which U.S. dollar denominated spot contract oil prices could be exchanged to Argentina pesos for invoicing to buyers.

Operating expenses increased by 3% to $8.2 million and decreased by 14% to $14.6 million for the three and six months ended June 30, 2014, respectively, from the three and six months ended June 30, 2013. On a per BOE basis, operating expenses increased by 31% to $37.07 and by 1% to $29.42 for the three and six months ended June 30, 2014, respectively, from $28.36 and $29.26 in the three and six months ended June 30, 2013. In the six months ended June 30, 2014, the increase in operating costs on a per BOE basis was primarily due to $3.92 per BOE higher workover costs and higher production from a block which has higher per BOE operating costs, partially offset by lower labor expenses on the Puesto Morales Block.

DD&A expenses decreased by 36% to $4.8 million and by 11% to $13.7 million for the three and six months ended June 30, 2014, compared with $7.4 million and $15.4 million in the three and six months ended June 30, 2013. On a per BOE basis, DD&A expenses decreased by 18% to $21.70 and increased by 3% to $27.55 for the three and six months ended June 30, 2014, respectively, from the three and six months ended June 30, 2013. We reclassified the Argentina assets on May 29, 2014, as assets held for resale and ceased recognizing DD&A expense on the assets from this date.

G&A expenses were $3.2 million ($14.67 per BOE) and $5.6 million ($11.23) for the three and six months ended June 30, 2014, compared with $2.7 million ($9.50 per BOE) and $5.1 million ($8.75 per BOE) in the three and six months ended June 30, 2013.

For the three and six months ended June 30, 2014, foreign exchange losses were $0.0 million and $4.4 million, respectively, compared with $0.6 million and $1.8 million in the three and six months ended June 30, 2013. The losses primarily related to realized foreign exchange losses on monetary assets in Argentina during the period. The Argentina Peso weakened by 2% and 5% against the U.S. dollar in the three months ended June 30, 2014 and in the three months ended June 30, 2013, respectively and by 25% and 10% against the U.S. dollar in the six months ended June 30, 2014 and the three months ended June 30, 2013, respectively.

Capital Program - Discontinued Operations

Capital expenditures in the three months ended June 30, 2014, included drilling of $9.3 million, G&G expenditures of $1.3 million, facilities of $0.7 million and other expenditures of $0.5 million, resulting in capital expenditures of $11.8 million and bringing total net capital expenditures for the six months ended June 30, 2014, to $18.3 million.

In Argentina, during the second quarter of 2014, the Proa-3 development well on the Surubi Block (85% WI, operated) began production as an oil producer and we performed workovers on a well on the El Vinalar Block (100% WI, operated).

Liquidity and Capital Resources

At June 30, 2014, we had cash and cash equivalents of $332.4 million compared with $428.8 million at December 31, 2013.

We believe that our cash resources, including cash on hand and cash generated from operations, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2014 and our planned operations for the next 12 months, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc., in interest earning current accounts or are invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At June 30, 2014, 72% of our cash and cash equivalents was generally not available to fund domestic or head office operations unless funds are repatriated, because it was held by subsidiaries and partnerships outside of Canada and the United States. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The government in Brazil requires us to register funds that enter and exit the country with the central bank in Brazil. In Brazil and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in the Special Exchange Regime, which allows us to receive revenue in U.S. dollars offshore. We may also pay invoices denominated in U.S. dollars for our Colombian business from these U.S. dollars received offshore. In Peru, expenditures may be paid in local currency or U.S. dollars.

At June 30, 2014, one of our subsidiaries had a credit facility with a syndicate of banks, led by Wells Fargo Bank National Association as administrative agent. This reserve-based facility has current borrowing base of $150 million and a maximum borrowing base up to $300 million and is supported by the present value of the petroleum reserves of two of our subsidiaries with operating branches in Colombia and our subsidiary in Brazil. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus a margin ranging between 2.25% and 3.25% per annum depending on the rate of borrowing base utilization. In addition, a stand-by fee of 0.875% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. The credit facility was entered into on August 30, 2013, and became effective on October 31, 2013, for a three-year term. Subsequent to the effective date, we have not drawn down any amounts under the new credit facility. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. Under the terms of the credit facility, we cannot pay any dividends to our shareholders if we are in default under the facility and, if we are not in default, we are required to obtain bank approval for any dividend payments exceeding $2.0 million in any fiscal year.

Cash Flows

During the six months ended June 30, 2014, our cash and cash equivalents decreased by $96.4 million as a result of cash used in investing activities of $127.4 million (including $12.4 million of cash used by investing activities of discontinued operations), partially offset by cash provided by operating activities of $23.9 million (included $4.8 million of cash used in operating activities of discontinued operations) and cash provided by financing activities of $7.1 million. During the six months ended June 30, 2013, our cash and cash equivalents increased by $69.4 million as a result of cash provided by operating activities of $248.8 million (included $19.0 million of cash provided by operating activities of discontinued operations) and cash provided by financing activities of $3.0 million, partially offset by cash used in investing activities of $182.4 million (included $10.3 million cash used for investing activities of discontinued operation).

Cash provided by operating activities of continuing operations in the six months ended June 30, 2014, was primarily affected by decreased oil and natural gas sales, increased G&A expenses, realized foreign exchange losses, and a $143.1 million change in assets and liabilities from operating activities. These decreases were partially offset by lower operating and income tax expenses and realized financial instrument gains. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $67.9 million primarily due to an increase in the number of days of sales outstanding in Colombia as a result of a higher portion of sales being to Ecopetrol which has longer payment terms than our other significant customer; inventory increased by $9.3 million due to higher inventory in Colombia as a result of pipeline disruptions; accounts payable and accrued liabilities increased by $9.7 million due to the timing of payments for drilling activity; and net taxes payable decreased by $77.3 million resulting in net taxes receivable due to payment of 2013 income taxes in Colombia.

Cash provided by operating activities of continuing operations in the six months ended June 30, 2013, was affected by increased oil and natural gas sales, decreased G&A expenses and lower realized foreign exchange losses. These increases were partially offset by increased operating and income tax expenses and a $41.5 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $0.8 million; inventory decreased by $13.1 million primarily due to the timing of recognition of oil sales to a customer in Colombia where the sale was recognized when the customer exported oil; accounts payable and accrued liabilities decreased by $9.1 million due to the timing of payments for drilling activity and reduced capital activity; and net taxes receivable decreased by $37.7 million resulting in net taxes payable due to the reimbursement of value added tax receivable and increased taxable income in Colombia.

Cash used in investing activities of continuing operations in the six months ended June 30, 2014, included cash capital expenditures of $158.2 million which was partially offset by proceeds from the sale of the Argentina business unit net of cash sold and transaction costs of $42.8 million and a decrease in restricted cash of $0.4 million. Cash outflows from investing activities of continuing operations in the six months ended June 30, 2013, included cash capital expenditures of $169.4 million and an increase in restricted cash of $4.3 million, partially offset by proceeds from sale of oil and gas properties of $1.5 million.

Cash provided by financing activities of continuing operations in the six months ended June 30, 2014 and 2013, related to proceeds from issuance of shares of our Common Stock upon the exercise of stock options.

Off-Balance Sheet Arrangements

As at June 30, 2014, we had no off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2013 Annual Report on Form 10-K, filed with the SEC on February 26, 2014, and have not changed materially since the filing of that document, except as disclosed below.

Derivative Activities

In February 2014, we purchased Colombian peso non-deliverable forward contracts for purposes of fixing the exchange rate at which we will purchase Colombian pesos to settle our income tax installment payments due in April and June 2014. Under the terms of our foreign exchange forward contracts, we will receive Colombian pesos and pay

U.S. dollars based on a total notional amount.

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

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

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

Accounting Pronouncements Not Yet Adopted

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Our principal market risk relates to oil prices. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to WTI or Brent and adjusted for quality each month.

Foreign currency risk is a factor for our company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. We have engaged in non-deliverable foreign exchange contracts to buy Colombian pesos in order to fix the exchange rate of our income tax installment payments in Colombia. Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil.

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

Additionally, foreign exchange gains and losses result from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $96,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar. At June 30, 2014, we held Colombia peso non-deliverable forward contracts totaling 712.2 million Colombian pesos for purposes of fixing the exchange rate at which we will purchase Colombian pesos to settle our income tax installment payments due in February 2015.

Exchange Rate Sensitivity

The table below provides information about our foreign currency forward exchange agreement at June 30, 2014, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equals the fair value of the contract. The information is presented in U.S. dollars because that is the registrant's reporting currency. The increase or decrease in the value of the forward contract is offset by the increase or decrease to the U.S. dollar equivalent of the Colombian peso current tax liabilities.

Forward contracts

Currency	Contract Type	Notional (Millions of Colombian Pesos)	Weighted Average Fixed Rate Received (Colombian Pesos - U.S. Dollars)	Fair Value of the Forward Contracts (thousands of U.S. Dollars)	Expiration
Colombian pesos	Buy	712.2	1,976	12	February 2015

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

Equity Investment in Madalena Energy Inc.

We hold an equity investment in Madalena Energy Inc. ("Madalena"), received as consideration in the sale of our Argentina business unit, which closed June 25, 2014. We hold 29,831,537 shares of Madalena which had a value of $14.3 million and represented approximately 5.7% of Madalena's outstanding shares at June 30, 2014. These shares trade on the TSX Venture Exchange, and as such are subject to changes in value that are outside of our control. Pursuant to Canadian securities regulation we are unable to trade these shares before October 26, 2014. In addition, we may face other market related obstacles such as trading volume and value in divesting these shares.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of June 30, 2014, 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, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission published an updated Internal Control - Integrated Framework and related illustrative documents which will supersede the 1992 COSO Framework as of December 15, 2014. As of June 30, 2014, Gran Tierra was utilizing the original framework published in 1992.

PART II - Other Information

Item 1. Legal Proceedings

As discussed in Note 9 of Notes to Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 above, Gran Tierra's production from the Costayaco Exploitation Area is subject to the HPR royalty, which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra's view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2014, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH's responses to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. As at June 30, 2014, total cumulative production from the Moqueta Exploitation Area was 3.2 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $52.9 million. At this time, no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH's interpretation is correct could be up to $35.6 million as at June 30, 2014. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

Item 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, 2013, filed with the Securities and Exchange Commission on February 26, 2014, are set forth below and are unchanged substantively at June 30, 2014, other than those designated by an asterisk "*", which changes include the deletion of disclosure in risk factors relating to our former Argentina operations, which have been deleted as we sold our Argentina business unit on June 25, 2014, as well as the deletion of those entire risk factors relating solely to our former Argentina operations.

Risks Related to Our Business

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

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

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

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Catatumbo, Cauca, Llanos, Sinu-San Jacinto, Middle Magdalena and Lower Magdalena Basins. The Putumayo and Catatumbo regions have been the breeding place of guerrilla activity. Pipelines have been primary targets because such pipelines cannot be adequately secured due to the sheer length of such pipelines and the remoteness of the areas in which the pipelines are laid. The Ecopetrol-operated Trans-Andean oil pipeline (the "OTA pipeline") which transports oil from the Putumayo region and upon which we materially rely has been targeted by these guerrilla groups. Starting in 2008, the OTA pipeline experienced outages of various lengths. In 2012, the OTA pipeline was shutdown for over 162 days and the shutdown had a material adverse effect on our deliveries to Ecopetrol and our financial performance for 2012. Recently we have experienced outages from October 2012 through to August 2014. In 2013, the OTA pipeline was shutdown for approximately 229 days. In the six months ended June 30, 2014, the OTA pipeline was shutdown for approximately 92 days. We have employed mitigation strategies as discussed in the risk "We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses" later in this section. Such disruptions may continue indefinitely and could harm our business.

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

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

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

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

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

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

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, June, July and August of 2009, June, August, and September 2010, February 2011, February to August of 2012 and October 2012 to August 2014, as a result of sabotage by guerrillas. In addition, there is competition for space in these pipelines, and additional discoveries in our area of operations by other companies could decrease the pipeline capacity available to us. Trucking is an alternative to transportation by pipeline; however, it is generally more expensive and carries higher safety risks for us, our employees and the public.

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

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

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

Oil sales in Colombia are mainly to Ecopetrol and, in 2013 and during the six months ended June 30, 2014, to another customer. While oil prices in Colombia are related to international market prices, lack of competition and reliance on a limited number of customers for sales of oil may diminish prices and depress our financial results.

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

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

We operate our business in Colombia, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as nationalization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. Our production in Brazil was shut in for three weeks in October 2013 as a result of a strike by employees of Petrobras which affected the crude oil receiving terminal we use in the Recôncavo Basin, and we have experienced minor delays in trucking operations due to demonstrations and strikes in our operating area during the six months ended June 30, 2014. We do not know how long such labor action will last, and if it lasts a significant amount of time, it may affect our ability to meet our production targets.

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

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

Recently, in the Department of Putumayo in Colombia where we operate, despite a company's compliance with legislative requirements for prior consultation of communities and minority ethnic groups and the receipt of the necessary permits to drill and operate, new ethnic groups have been threatening, and in some cases using, the Judicial Branch of the Government, Superior Court of the Judicial District of Mocoa (the "Local Court") to require that they be consulted, and thereby obtain benefits from companies operating in the Department of Putumayo as a result of those consultations. The Local Court has the ultimate jurisdiction to determine, upon a writ for protection or tutela, by an ethnic group (i) whether there has been a violation of a fundamental right to prior consultation by act or omission of a public authority or individual and (ii) whether the ethnic group is legitimate. If the Local Court determines that there has been a violation and the ethnic group is legitimate despite receipt by the company of its proper governmental permits, the Local Court has the power to invalidate a company's permits and force the company to cease operations immediately until such time as the company can successfully appeal to the Supreme Court to overturn the Local Court's decision or prior consultations are completed and the permits effective once again.

Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government and judicial authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired and, if we are faced with a tutela, our operations in the area(s) governed by a Local Court's order may be shut down for a period of time thereby causing significant harm to our business in Colombia.

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

At June 30, 2014, 72% of our cash and cash equivalents was held by subsidiaries and partnerships outside of Canada and the United States. This cash is generally not available to fund domestic or head office operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay taxes in certain jurisdictions on the distribution of accumulated earnings.

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 2014 calls for approximately $482 million to fund our exploration and development, which we intend to fund through cash on hand and cash flows from operations at current production and commodity price levels. Funding this program relies in part on oil prices remaining close to current levels or higher 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 enter into strategic and business relationships, which may take the form of joint ventures with other parties or with local government bodies, or contractual arrangements with other oil and gas companies, including those that supply equipment and other resources that we will use in our business. We also have an active business development program to develop those relationships and foster new relationships. We may not be able to establish these business relationships, or if established, we may choose the wrong partner or we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to take to fulfill our obligations to these partners or maintain our relationships. If we fail to make the cash calls required by our joint venture partners in the joint ventures we do not operate, we may be required to forfeit our interests in these joint ventures. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

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

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

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

*Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations

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

As discussed in Note 9 to the Condensed Consolidated Financial Statements in Part I, Item 1 above, our production from the Costayaco Exploitation Area is subject to the HPR royalty, which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which we contested because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. We also believe that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have initiated the dispute resolution process under the Chaza Contract and filed an arbitration claim seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that we breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. As at June 30, 2014, total cumulative production from the Moqueta Exploitation Area was 3.2 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $52.9 million. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as we do not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $35.6 million as at June 30, 2014. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

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

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

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

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

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

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

*Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. We are also exposed to transaction risk on settlement of payables and receivables denominated in foreign currency. We have purchased non-deliverable foreign exchange contracts to hedge some of the transaction risk related to our Colombian income tax payable. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Production in Brazil is invoiced and paid in Brazilian Reals. Since September 1, 2005, the exchange rate of the Brazilian Real has varied between 1.56 Reals to one U.S. dollar to 2.45 Reals to the U.S. dollar, a variance of 57%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the Colombian peso strengthened by 4% against the U.S. dollar in the six months ended June 30, 2014, resulting in a foreign exchange loss.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We May not be Able to Effectively Manage Our Growth, Which May Harm Our Profitability.

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

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

- allocate our human resources optimally;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Risks Related to Our Industry

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

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

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and technical conditions. While we will endeavor to effectively manage these conditions, we may not be able to do so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

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

We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. For example, the permitting process in Peru takes significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere. In Colombia, other drilling and development projects are being delayed, most significantly our Moqueta field development, because of delays at the Ministry of the Environment and other government departments. In addition, environmental and social evaluation demands have increased in Colombia, causing permit processing to take longer than previously experienced in the areas where we operate and, in some areas where we operate, such as the Department of Putumayo, despite the receipt of the proper permits, there are new procedures being utilized by new ethnic communities to make further economic demands on operators to continue to operate in the region, such as the use of the Local Court to obtain a tutela, or writ of protection. These delays and demands are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations. For example, currently in Brazil, we are subject to restrictions on flaring natural gas, which have the impact of limiting our production capacity. We have examined other alternatives for producing and delivering the gas, however, however, to date, we have not been able to successfully implement any of these alternatives. Additionally in Brazil, the exploration phase of three of our concession agreements was due to expire on November 24, 2013. We have submitted an application to the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis for extensions of the exploration phase of these concession agreements as provided for in the agreements; however, we may not be successful and loss of these agreements may impair our ability to grow our business in Brazil.

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

Oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our exploration expenditures may not result in new discoveries of oil or natural gas in commercially viable quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. For example, in January 2014, the Corunta-1 exploration well on the west flank of the Moqueta field encountered drilling problems prior to reaching the reservoir target on this long-reach deviated well, and the decision was made to abandon the well. The target location will be drilled again this year with a revised drilling plan. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations.

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

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

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

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

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

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

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

In 2012, we recorded a ceiling test impairment loss of $20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. The farm-out agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period. In 2013, we recorded a $2.0 million ceiling test impairment loss in our Brazil cost center related to lower realized prices and an increase in operating costs.

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

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

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

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for West Texas Intermediate ("WTI") per bbl has varied from $66 in 2006 to $98 in 2013, and $99 in the six months ended June 30, 2014, demonstrating the inherent volatility in the market. The average Brent oil price per bbl was $111 in 2011, $112 in 2012, $109 in 2013 and $109.70 in the six months ended June 30, 2014. Given the current economic environment and unstable conditions in the Middle East, North Africa, the United States and Europe, the oil price environment is unpredictable and unstable. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations and quantities of reserves recoverable on an economic basis.

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

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

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

Penalties We May Incur Could Impair Our Business.

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

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

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

Environmental Risks May Adversely Affect Our Business.

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

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

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

Challenges to Our Properties May Impact Our Financial Condition.

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

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

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

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

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

Risks Related to Our Common Stock

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

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

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

- announcements by relevant governments pertaining to incentives for alternative energy development programs;
- fluctuations in interest rates, exchange rates and the availability of capital in the capital markets; and
- significant sales of shares of our Common Stock, including sales by future investors in future offerings we expect to make to raise additional capital.

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

- quarterly variations in our revenues and operating expenses; and

• additions and departures of key personnel.

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

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

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

Item 6. Exhibits

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

SIGNATURES

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

GRAN TIERRA ENERGY INC.

Date: August 6, 2014	/s/ Dana Coffield By: Dana Coffield Chief Executive Officer and President (Principal Executive Officer)
Date: August 6, 2014	/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, filed with the SEC on August 1, 2008 (SEC File No. 001-34018).
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, filed with the SEC on October 10, 2008 (SEC File No. 333-153376).
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).
2.4	Share Purchase and Sale Offer, dated May 29, 2014, by Gran Tierra Petroco Inc. +	Incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q, filed with the SEC on July 1, 2014 (SEC File No. 001-34018).
2.5	Share Purchase and Sale Offer, dated May 29, 2014, by Gran Tierra Energy Inc., an Alberta corporation, and PCESA Petroleros Canadienses De Ecuador S.A. +	Incorporated by reference to Exhibit 2.2 to the Quarterly Report on Form 10-Q, filed with the SEC on July 1, 2014 (SEC File No. 001-34018).
3.1	Amended and Restated Articles of Incorporation.	Incorporated by reference to Exhibit 3.1 to the Annual Report on Form 10-K, filed with the SEC on February 26, 2014 (SEC File No. 001-34018).
3.2	Amended and Restated Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed with the SEC on February 26, 2014 (SEC File No. 001-34018).
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 dated April 15, 2014 to Expat Assignment Letter Agreement between Gran Tierra Energy Inc. and Duncan Nightingale.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 7, 2014 (SEC File No. 001-34018).
10.2	Compensation Arrangements with Shane O'Leary, as retiring Chief Operating Officer, Duncan Nightingale, as Chief Operating Officer, and Adrian Coral, as President of Gran Tierra Energy Colombia, Ltd.	Described in Item 5.02 of the Current Report on Form 8-K, filed with the SEC on July 1, 2014 (SEC File No. 001-34018), which description is incorporated by reference here.
10.3	Executive Employment Agreement dated July 31, 2014, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale.	Filed herewith.
10.4	Employment Agreement dated July 31, 2014, between Gran Tierra Energy Colombia Ltd. and Adrián Santiago Coral Pantoja.	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.