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

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

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

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2012

OR

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

FOR THE TRANSITION PERIOD FROM __________ TO __________

Commission file number 001-34018

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

Nevada (State or other jurisdiction of incorporation or organization)	98-0479924 (I.R.S. employer identification number)
300, 625 11 Avenue S.W. Calgary, Alberta, Canada (Address of principal executive offices)	T2R 0E1 (Zip code)

(403) 265-3221
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES x 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 x

On May 1, 2012, the following numbers of shares of the registrant's capital stock were outstanding: 266,474,815 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 6,223,810 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 8,188,780 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Three Months Ended March 31, 2012

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STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

GLOSSARY OF OIL AND GAS TERMS

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

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

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

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

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

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

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

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

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

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 (LKH) 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.

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.

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PART 1

Item 1 - Financial Statements

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

	Three Months Ended March 31, 2012	2011
REVENUE AND OTHER INCOME		
Oil and natural gas sales	$ 155,248	$ 122,296
Interest income	703	223
	155,951	122,519
EXPENSES		
Operating	24,487	16,396
Depletion, depreciation, accretion and impairment (Note 5)	60,367	63,357
General and administrative	15,899	13,638
Equity tax (Note 8)	-	8,050
Financial instruments gain (Notes 3 and 6)	-	(230)
Gain on acquisition (Note 3)	-	(24,300)
Foreign exchange loss	24,375	5,199
	125,128	82,110
INCOME BEFORE INCOME TAXES	30,823	40,409
Income tax expense (Note 8)	(31,136)	(26,696)
NET (LOSS) INCOME AND COMPREHENSIVE (LOSS) INCOME	(313)	13,713
RETAINED EARNINGS, BEGINNING OF PERIOD	185,014	58,097
RETAINED EARNINGS, END OF PERIOD	$ 184,701	$ 71,810
NET (LOSS) INCOME PER SHARE — BASIC	$ (0.00)	$ 0.05
NET (LOSS) INCOME PER SHARE — DILUTED	$ (0.00)	$ 0.05
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	278,734,280	260,930,753
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	278,734,280	267,819,800

(See notes to the condensed consolidated financial statements)

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

	March 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$230,076	$ 351,685
Restricted cash	2,880	1,655
Accounts receivable	145,606	69,362
Inventory (Note 5)	14,339	7,116
Taxes receivable	19,501	21,485
Prepaids	4,215	3,597
Deferred tax assets (Note 8)	3,229	3,029
Total Current Assets	419,846	457,929
Oil and Gas Properties (using the full cost method of accounting)		
Proved	627,620	618,982
Unproved	433,530	417,868
Total Oil and Gas Properties	1,061,150	1,036,850
Other capital assets	8,441	7,992
Total Property, Plant and Equipment (Note 5)	1,069,591	1,044,842
Other Long-Term Assets		
Restricted cash	43,039	13,227
Deferred tax assets (Note 8)	6,462	4,747
Other long-term assets	4,994	3,454
Goodwill	102,581	102,581
Total Other Long-Term Assets	157,076	124,009
Total Assets	$1,646,513	$ 1,626,780
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$37,775	$ 82,189
Accrued liabilities	90,238	66,832
Taxes payable	120,328	95,482
Asset retirement obligation (Note 7)	-	326
Total Current Liabilities	248,341	244,829
Long-Term Liabilities		
Deferred tax liability (Note 8)	198,505	186,799
Equity tax payable (Note 8)	7,029	6,484
Asset retirement obligation (Note 7)	12,124	12,343
Other long-term liabilities	2,187	2,007
Total Long-Term Liabilities	219,845	207,633
Commitments and Contingencies (Note 9)		

Shareholders’ Equity		
Common shares (Note 6) (264,256,159 and 262,304,249 common shares and 14,717,917 and 16,323,819 exchangeable shares, par value $0.001 per share, issued and outstanding as at March 31, 2012 and December 31, 2011, respectively)	7,983	7,510
Additional paid in capital	983,919	980,014
Warrants (Note 6)	1,724	1,780
Retained earnings	184,701	185,014
Total Shareholders’ Equity	1,178,327	1,174,318
Total Liabilities and Shareholders’ Equity	$1,646,513	$ 1,626,780

(See notes to the condensed consolidated financial statements)

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

	Three Months Ended March 31, 2012	2011
Operating Activities		
Net (loss) income	$ (313)	$ 13,713
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:		
Depletion, depreciation, accretion and impairment	60,367	63,357
Deferred taxes (Note 8)	(5,250)	(187)
Stock-based compensation (Note 6)	3,192	3,453
Gain on financial instruments (Note 3)	-	(62)
Unrealized foreign exchange loss	21,351	4,458
Settlement of asset retirement obligation (Note 7)	(404)	(4)
Equity tax	-	6,132
Gain on acquisition (Note 3)	-	(24,300)
Net change in assets and liabilities from operating activities		
Accounts receivable	(72,865)	(83,036)
Inventory	(4,500)	736
Prepaids	(618)	(831)
Accounts payable and accrued and other liabilities	(34,035)	(22,756)
Taxes receivable and payable	19,595	8,101
Net cash used in operating activities	(13,480)	(31,226)
Investing Activities		
Increase in restricted cash	(31,037)	(5,600)
Additions to property, plant and equipment	(77,983)	(77,516)
Proceeds from disposition of oil and gas property (Note 5)	-	3,253
Cash acquired on acquisition (Note 3)	-	7,747
Proceeds on sale of asset-backed commercial paper (Note 3)	-	22,679
Net cash used in investing activities	(109,020)	(49,437)
Financing Activities		
Settlement of bank debt (Notes 3 and 11)	-	(22,853)
Proceeds from issuance of common shares	891	1,989
Net cash provided by (used in) financing activities	891	(20,864)
Net decrease in cash and cash equivalents	(121,609)	(101,527)
Cash and cash equivalents, beginning of period	351,685	355,428
Cash and cash equivalents, end of period	$ 230,076	$ 253,901
Cash	$ 148,035	$ 243,399

Term deposits	82,041	10,502
Cash and cash equivalents, end of period	$ 230,076	$ 253,901
Supplemental cash flow disclosures:		
Cash paid for interest	$ -	$ 668
Cash paid for income taxes	$ 13,733	$ 9,693
Non-cash investing activities:		
Non-cash working capital related to property, plant and equipment, end of period	$ 53,090	$ 42,698

(See notes to the condensed consolidated financial statements)

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

	Three Months Ended March 31, 2012	Year Ended December 31, 2011
Share Capital		
Balance, beginning of period	$7,510	$ 4,797
Issue of common shares	473	2,713
Balance, end of period	7,983	7,510
Additional Paid in Capital		
Balance, beginning of period	980,014	821,781
Issue of common shares	105	142,109
Exercise of warrants (Note 6)	56	411
Exercise of stock options (Note 6)	313	1,990
Stock-based compensation (Note 6)	3,431	13,723
Balance, end of period	983,919	980,014
Warrants		
Balance, beginning of period	1,780	2,191
Exercise of warrants (Note 6)	(56)	(411)
Balance, end of period	1,724	1,780
Retained Earnings		
Balance, beginning of period	185,014	58,097
Net (loss) income	(313)	126,917
Balance, end of period	184,701	185,014
Total Shareholders' Equity	$1,178,327	$ 1,174,318

(See notes to the condensed consolidated financial statements)

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

1. Description of Business

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

2. Significant Accounting Policies

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

The note disclosure requirements of annual consolidated financial statements provide additional disclosures to that required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements as at and for the year ended December 31, 2011 included in the Company’s 2011 Annual Report on Form 10-K, filed with the Securities and Exchange Commission (“SEC”) on February 27, 2012.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2011 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as disclosed below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

Revenue recognition

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

Adopted accounting pronouncements

Goodwill

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

Recently issued accounting pronouncements

Disclosure about Offsetting Assets and Liabilities

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

3. Business Combination

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

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

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

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

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

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

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

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

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

As shown above, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra initially recognized a gain of $24.3 million, which was reported as "Gain on acquisition", in the consolidated statement of operations for the three months ended March 31, 2011. Subsequent to the initial allocation of the consideration in the first quarter of 2011, further assessments of Petrolifera's tax position resulted in a reduction of the gain on acquisition to $21.7 million. The gain reflects the impact on Petrolifera's pre-acquisition market value of a lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

As part of the assets acquired and included in the net working capital in the allocation of the consideration transferred, the Company assigned $22.5 million in fair value to investments in notes that Petrolifera received in exchange for asset-backed commercial paper ("ABCP") with a face value of $31.3 million. On March 28, 2011, these notes were sold to an unrelated party for proceeds of $22.7 million after the associated line of credit was settled resulting in a financial instruments gain for the three months ended March 31, 2011 of $0.2 million.

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

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

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

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Pro forma results for the three months ended March 31, 2011 are shown below, as if the acquisition had occurred on January 1, 2010. Pro forma results are not indicative of actual results or future performance.

(Thousands of U.S. Dollars except per share amounts)		Three Months Ended March 31, 2011	
Revenue and other income	$	131,714	
Net loss	$	(21,711	)
Net loss per share - basic	$	(0.08	)
Net loss per share - diluted	$	(0.08	)

The supplemental pro forma earnings of Gran Tierra for the three months ended March 31, 2011 were adjusted to exclude $4.4 million of acquisition costs recorded in general and administrative (“G&A”) expenses and the $24.3 million gain on acquisition because they are not expected to have a continuing impact on Gran Tierra’s results of operations. Petrolifera’s oil and natural gas sales and results of operations between the Acquisition Date and March 31, 2011 were not significant and therefore are not separately disclosed.

4. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company’s reportable segments are Colombia, Argentina and Peru based on a geographic organization. The Company’s operations in Brazil are not a reportable segment because the level of activity in Brazil was not significant at March 31, 2012 or December 31, 2011. The All Other category represents the Company’s corporate activities and operations in Brazil.

The accounting policies of the reportable segments are the same as those described in Note 2. The Company evaluates segment performance based on income or loss before income taxes. The segmented results include the operations of Petrolifera subsequent to March 18, 2011, the date of acquisition of Petrolifera (Note 3).

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

(Thousands of U.S. Dollars except per unit of production amounts)	Three Months Ended March 31, 2012							
	Colombia	Argentina		Peru		All Other		Total
Oil and natural gas sales	$138,633	$15,369		$-		$1,246		$155,248
Interest income	204	47		15		437		703
Depletion, depreciation, accretion and impairment	32,286	5,925		115		22,041		60,367
Depletion, depreciation, accretion and impairment - per unit of production	25.80	22.80		-		1,741.47		39.62
Income (loss) before income taxes	60,120	(477	)	(727	)	(28,093	)	30,823
Segment capital expenditures	$20,349	$14,105		$16,655		$36,482		$87,591

(Thousands of U.S. Dollars except per unit of production amounts)	Three Months Ended March 31, 2011				
	Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$117,304	$4,992	$-	$-	$122,296
Interest income	87	-	-	136	223
Depletion, depreciation, accretion and impairment	30,036	1,147	31,933	241	63,357

Depletion, depreciation, accretion and impairment - per unit of production	24.77	11.90	-	-	48.39
Income (loss) before income taxes	57,886	(430)	(32,625)	15,578	40,409
Segment capital expenditures (1)	$42,264	$11,622	$14,287	$930	$69,103

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

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

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In the three months ended March 31, 2012 and 2011, the Company had one significant customer for its Colombian oil, Ecopetrol S.A. (“Ecopetrol”). Sales to Ecopetrol accounted for 85% and 96% of the Company’s revenues for the three months ended March 31, 2012 and 2011, respectively. In the three months ended March 31, 2012, the Company had two significant customers in Argentina, Shell C.A.P.S.A. (“Shell”) and Refineria del Norte S.A. (“Refiner”). Sales to Shell and Refiner accounted for 4% and 3%, respectively, of the Company’s oil and natural gas sales for the three months ended March 31, 2012. In the three months ended March 31, 2011, Refiner was the Company’s only significant customer in Argentina.

(Thousands of U.S. Dollars)	As at March 31, 2012				
	Colombia	Argentina	Peru	All Other	Total
Property, plant and equipment	$801,810	137,414	50,845	79,522	$1,069,591
Goodwill	102,581	-	-	-	102,581
Other assets	269,744	38,103	8,602	157,892	474,341
Total Assets	$1,174,135	$175,517	$59,447	$237,414	$1,646,513

	As at December 31, 2011				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	All Other	Total
Property, plant and equipment	$816,396	129,072	34,305	65,069	$1,044,842
Goodwill	102,581	-	-	-	102,581
Other assets	269,843	34,672	9,597	165,245	479,357
Total Assets	$1,188,820	$163,744	$43,902	$230,314	$1,626,780

5. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

	As at March 31, 2012			As at December 31, 2011		
(Thousands of U.S. Dollars)	Cost	Accumulated depletion, depreciation and impairment	Net book value	Cost	Accumulated depletion, depreciation and impairment	Net book value
Oil and natural gas properties						
Proved	$1,252,252	(624,632)	627,620	$1,181,503	$ (562,521)	$ 618,982
Unproved	433,530	-	433,530	417,868	-	417,868
	1,685,782	(624,632)	1,061,150	1,599,371	(562,521)	1,036,850
Furniture and fixtures and leasehold improvements	7,226	(4,457)	2,769	6,973	(4,002)	2,971
Computer equipment	9,370	(4,422)	4,948	8,443	(4,174)	4,269
Automobiles	1,295	(571)	724	1,295	(543)	752
Total Property, Plant and Equipment	$1,703,673	$ (634,082)	$ 1,069,591	$1,616,082	$ (571,240)	$ 1,044,842

Depletion and depreciation expense on property, plant and equipment for the three months ended March 31, 2012 was $42.6 million (three months ended March 31, 2011 - $32.1 million). A portion of depletion and depreciation expense was capitalized as inventory during the period.

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

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

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

In the three months ended March 31, 2011, the Company recorded ceiling test impairment loss in the Company's Peru cost center of $31.9 million. This impairment charge related to seismic and drilling costs from a dry well.

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

The amounts capitalized in each of the Company's cost centers during the three months ended March 31, 2012 and 2011 were as follows:

	Three Months Ended March 31, 2012				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	$1,852	$1,080	$927	$1,068	$4,927
Capitalized stock-based compensation	$114	$66	$-	$59	$239

	Three Months Ended March 31, 2011				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	$1,815	$410	$294	$-	$2,519
Capitalized stock-based compensation	$76	$47	$-	$-	$123

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. As at March 31, 2012, the Company had $274.3 million (December 31, 2011 - $274.8 million) of unproved assets in Colombia, $52.9 million (December 31, 2011 - $57.0 million) of unproved assets in Argentina, $50.2 million (December 31, 2011 - $33.7 million) of unproved assets in Peru and $56.1 million (December 31, 2011 - $52.4 million) of unproved assets in Brazil for a total of $433.5 million (December 31, 2011 - $417.9 million). These properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

Inventories

As at March 31, 2012, oil and supplies inventories were $12.1 million and $2.2 million, respectively (December 31, 2011 - $4.7 million and $2.4 million, respectively).

6. Share Capital

The Company's authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as common stock, par value $0.001 per share, 25 million are designated as preferred stock, par value $0.001 per share, and two shares are designated as special voting stock, par value $0.001 per share. As at March 31, 2012, outstanding share capital consists of 264,256,159 common voting shares of the Company, 8,494,107 exchangeable shares of Gran Tierra Exchange Co., automatically exchangeable on November 14, 2013, and 6,223,810 exchangeable shares of Goldstrike Exchange Co., automatically exchangeable on November 10, 2012. The exchangeable shares of Gran Tierra Exchange Co., were issued upon acquisition of Solana Resources Limited

("Solana"). The exchangeable shares of Gran Tierra Goldstrike Inc. were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. Each exchangeable share is exchangeable into one common voting share of the Company. The holders of common 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 common stock. Holders of exchangeable shares have substantially the same rights as holders of common voting shares.

Warrants

At March 31, 2012, the Company had 6,098,224 warrants outstanding to purchase 3,049,112 common shares for $1.05 per share, expiring between June 20, 2012 and June 30, 2012. For the three months ended March 31, 2012, 100,003 common shares were issued upon the exercise of 200,006 warrants (three months ended March 31, 2011, 210,000 common shares were issued upon the exercise of 420,000 warrants).

The Company issued 4,125, 036 Replacement Warrants in connection with its acquisition of Petrolifera during March 2011 (Note 3). The Replacement Warrants expired unexercised during August 2011.The fair value of the Replacement Warrants as of March 31, 2011 was determined using the Black-Scholes option pricing model with the following assumptions:

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

During the three months ended March 31, 2011, a financial instruments gain resulting from the change in fair value of the Replacement Warrants of $32,075 was recorded.

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Stock Options

For the three months ended March 31, 2012, the stock-based compensation expense was $3.4 million (three months ended March 31, 2011 - $3.6 million) of which $2.9 million (three months ended March 31, 2011 - $3.2 million) was recorded in G&A expenses, $0.3 million was recorded in operating expense (three months ended March 31, 2011 – $0.3 million) and $0.2 million of stock-based compensation was capitalized as part of exploration and development costs (three months ended March 31, 2011 – $0.1 million).

At March 31, 2012, there was $18.3 million (December 31, 2011 - $11.7 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next three years.

The following table provides information about stock option activity for the three months ended March 31, 2012:

	Number of Outstanding Options		Weighted Average Exercise Price $/Option	
Balance, December 31, 2011	12,864,002	$	4.90	
Granted in 2012	3,213,150		5.81	
Exercised in 2012	(246,005	)	(3.20	)
Forfeited in 2012	(136,646	)	(7.05	)
Balance, March 31, 2012	15,694,501	$	5.10	

The weighted average grant date fair value for options granted in the three months ended March 31, 2012 was $3.37 (three months ended March 31, 2011 - $5.20). The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model based on assumptions noted in the following table.

		Three Months Ended March 31, 2012	
Dividend yield (per share)	$	nil	
Volatility		75	%
Risk-free interest rate		0.4	%
Expected term		4-6 years	

Weighted average shares outstanding

	Three Months Ended March 31, 2012	2011	
Weighted average number of common and exchangeable shares outstanding	278,734,280	260,930,753	
Shares issuable pursuant to warrants	-	3,203,257	
Shares issuable pursuant to stock options	-	5,894,518	
Shares to be purchased from proceeds of stock options	-	(2,208,728	)
Weighted average number of diluted common and exchangeable shares outstanding	278,734,280	267,819,800	

Net (loss) income per share

For the three month period ended March 31, 2012, 15,694,501 options and 6,098,224 warrants to purchase 3,049,112 common shares were excluded from the diluted income per share calculation as the instruments were anti-dilutive. For the three months ended March 31, 2011, 4,125,036 Replacement Warrants were excluded from the diluted income per share calculation as the instruments were anti-dilutive.

7. Asset Retirement Obligation

As at March 31, 2012, the Company’s asset retirement obligation was comprised of a Colombian obligation in the amount of $5.6 million (December 31, 2011 - $5.5 million), an Argentine obligation in the amount of $6.0 million (December 31, 2011 - $6.7 million) and a Brazilian obligation in the amount of $0.5 million (December 31, 2011 - $0.5 million). As at March 31, 2012, the undiscounted asset retirement obligation was $29.2 million (December 31, 2011 - $29.9 million). Revisions to estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. Changes in the carrying amounts of the asset retirement obligation associated with the Company’s oil and natural gas properties were as follows:

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(Thousands of U.S. Dollars)	Three Months Ended March 31, 2012	Year Ended December 31, 2011
Balance, beginning of period	$ 12,669	$ 4,807
Settlements	(404)	(345)
Disposal	-	(172)
Liability incurred	193	867
Liability assumed in a business combination (Note 3)	-	4,901
Foreign exchange	35	17
Accretion	247	673
Revisions in estimated liability	(616)	1,921
Balance, end of period	$ 12,124	$ 12,669
Asset retirement obligation - current	$ -	$ 326
Asset retirement obligation – long-term	12,124	12,343
Balance, end of period	$ 12,124	$ 12,669

8. Taxes

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

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2012	2011
Income before income taxes	$ 30,823	$ 40,409
	35 %	35 %
Income tax expense expected	10,788	14,143
Foreign currency translation adjustments	8,718	1,981
Impact of foreign taxes	(631)	(1,598)
Stock-based compensation	1,003	1,143
Increase in valuation allowance	10,145	15,288
Branch and other foreign loss pick-up in the United States and Canada	(622)	(1,619)
Non-deductible third party royalty in Colombia	1,943	1,820
Non-taxable gain on acquisition	-	(8,527)
Other permanent differences	(208)	4,065
Total income tax expense	$ 31,136	$ 26,696
Current income tax	36,384	26,677
Deferred tax recovery	(5,248)	19
Total income tax expense	$ 31,136	$ 26,696

(Thousands of U.S. Dollars)	As at March 31, 2012	December 31, 2011
Deferred Tax Assets		
Tax benefit of loss carryforwards	$ 73,645	$ 63,910
Tax basis in excess of book basis	15,732	17,065
Foreign tax credits and other accruals	27,224	27,164
Capital losses	2,494	2,433

Deferred tax assets before valuation allowance	119,095	110,572
Valuation allowance	(109,404)	(102,796)
	$ 9,691	$ 7,776
Deferred tax assets - current	$ 3,229	$ 3,029
Deferred tax assets - long-term	6,462	4,747
	9,691	7,776
Deferred Tax Liabilities		
Long-term - book value in excess of tax basis	(198,505)	(186,799)
Net Deferred Tax Liabilities	$ (188,814)	$ (179,023)

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As at March 31, 2012, the Company had operating loss carryforwards of $388.5 million (December 31, 2011 - $361.6 million) and capital losses of $13.9 million (December 31, 2011 – $13.7 million). Of these losses, $368.4 million (December 31, 2011 - $339.8 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the net operating loss carryforwards expire between 2012 and 2031 and the capital losses expire between 2012 and 2016, while certain other jurisdictions allow net operating losses to be carried forward indefinitely. Of the total net operating loss carryforwards, $4.0 million will begin to expire by 2013.

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

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

	Three Months Ended March 31,	
	2012	2011
(Thousands of U.S. Dollars)		
Unrecognized tax benefit at January 1	$ 20,500	$ 4,175
Changes for positions relating to prior year	-	70
Additions to tax position related to the current year	-	12,364
Unrecognized tax benefit at March 31	$ 20,500	$ 16,609

The Company and its subsidiaries file income tax returns in the U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is subject to income tax examinations for the calendar tax years ended 2005 through 2011 in most jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefits disclosed above within the next twelve months.

Equity tax for the three months ended March 31, 2011 of $8.1 million represented a Colombian tax of 6% on a legislated measure which is based on the Company's Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period. The equity tax liability at March 31, 2012 and December 31, 2011 also partially related to an equity tax liability assumed upon the acquisition of Petrolifera.

9. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of March 31, 2012:

	As at March 31, 2012				
	Payments Due in Period				
	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
(Thousands of U.S. Dollars)					

Oil transportation services	$36,922	$13,072	$7,100	$7,100	$ 9,650
Drilling and geological and geophysical	58,336	47,086	11,250	-	-
Completions	24,821	19,201	5,620	-	-
Facility construction	41,389	24,557	16,832	-	-
Operating leases	7,661	3,085	3,142	1,434	-
Software and telecommunication	4,790	3,811	979	-	-
Consulting	1,989	1,989	-	-	-
Total	$175,908	112,801	44,923	8,534	9,650

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Indemnities

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

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

Letters of credit

At March 31, 2012, the Company had provided promissory notes totalling $24.5 million (December 31, 2011 - $20.7 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contingencies

Ecopetrol and Gran Tierra Energy Colombia Ltd. ("Gran Tierra Colombia"), the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long-term test of the Guayuyaco -1 and Guayuyaco -2 wells. There is a material difference in the interpretation of the procedure established in Clause 3.5 of Attachment-B of the Guayuyaco Association Contract. Ecopetrol interprets the contract to provide that the extended test production up to a value equal to 30% of the direct exploration costs of the wells is for Ecopetrol's account only and serves as reimbursement of its 30% back-in to the Guayuyaco discovery. Gran Tierra Colombia's contention is that this amount is merely the recovery of 30% of the direct exploration costs of the wells and not exclusively for the benefit of Ecopetrol. There has been no agreement between the parties, and Ecopetrol has filed a lawsuit in the Contravention Administrative Court in the District of Cauca regarding this matter. Gran Tierra Colombia filed a response on April 29, 2008 in which it refuted all of Ecopetrol's claims and requested a change of venue to the courts in Bogota. At this time no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. Ecopetrol is claiming damages of approximately $5.8 million.

Gran Tierra is subject to a third party 10% net profits interest on 50% of the Company's production from the Costayaco field that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There is currently a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party agreed to resolve this issue through an arbitration which was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. The Company now expects to receive the arbitrator's decision in the second quarter of 2012. At this time no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. The disputed amount at March 31, 2012 is $10.9 million (December 31, 2011 - $9.6 million).

Gran Tierra's production from the Costayaco field is subject to an additional royalty that applies when cumulative gross production from a commercial field is greater than five million barrels. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a non-compliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five million barrels. As at March 31, 2012, total cumulative production from the Moqueta field was 0.4 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH’s interpretation is successful is $7.4 million. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

Gran Tierra has several lawsuits and claims pending for which the Company currently cannot determine the ultimate result. Gran Tierra records costs as they are incurred or become probable and determinable. Gran Tierra believes the resolution of these matters would not have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flows.

10. Financial Instruments, Fair Value Measurements and Credit Risk

At March 31, 2012, the Company’s financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued liabilities. The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. At March 31, 2012, the Company did not have any financial assets or liabilities measured at fair value on the balance sheet and held no derivative instruments. The Company does not use derivative financial instruments for speculative purposes. The fair value of financial instruments at March 31, 2012 as disclosed above was determined using Level 3 inputs.

At March 31, 2011, the Replacement Warrants (Note 3) met the definition of a derivative. Because the exercise price of the Replacement Warrants was denominated in Canadian dollars, which is different from Gran Tierra's functional currency, the Replacement Warrants were not considered indexed to Gran Tierra's common shares and the Replacement Warrants could not be classified within equity. Therefore the Replacement Warrants were classified as a current liability on Gran Tierra's condensed consolidated balance sheet. Furthermore, these derivative instruments did not qualify as fair value hedges or cash flow hedges, and accordingly, changes in their fair value were recognized as income or expense in the consolidated statement of operations and retained earnings with a corresponding adjustment to the fair value of derivative instruments recognized on the balance sheet. The fair value of the Replacement Warrants at March 31, 2011 was determined using Level 3 inputs (Note 6).

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

At March 31, 2012, cash and cash equivalents and restricted cash included balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with governments and financial institutions with strong investment grade ratings, or the equivalent in the Company's operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in the Company's operating areas.

Most of the Company's accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the three months ended March 31, 2012, the Company had one significant customer for its Colombian oil, Ecopetrol, and in Argentina the Company had two significant customers, Shell and Refiner.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, monetary liabilities, which are mainly denominated in the local currency of the Colombian foreign operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $104,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

11. Bank Debt and Credit Facilities

Effective July 30, 2010, a subsidiary of Gran Tierra, Solana, established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve-based facility has a maximum borrowing base up to $100 million and is supported by the present value of the petroleum reserves of two of the Company's subsidiaries with operating branches in Colombia – Gran Tierra Colombia and Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. As at March 31, 2012 and December 31, 2011, the Company had not drawn down any amounts under this facility. In February 2012, BNP Paribas announced the sale of its North American reserve-based lending business to Wells Fargo Bank National Association. Solana's credit facility is expected to be part of that sale. Closing documents are being processed, and the sale is expected to be finalized in the second quarter of 2012.

12. Related Party Transactions

On January 12, 2011, the Company entered into an agreement to sublease office space to a company of which Gran Tierra's President and Chief Executive Officer serves as an independent director. The term of the sublease runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,400 per month plus approximately $5,600 of operating and other expense.

On August 3, 2010, Gran Tierra entered into a contract related to the Peru drilling program with a company for which one of Gran Tierra's directors is a shareholder and director. For the three months ended March 31, 2012, $nil million was incurred and capitalized under this contract (three months ended March 31, 2011 - $2.0 million) and at March 31, 2012, $nil was included in accounts payable related to this contract (December 31, 2011 - $nil).

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

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

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

The following discussion of our financial condition and results of operations should be read in conjunction with the Financial Statements as set out in Part I – Item 1 of this Quarterly Report on Form 10-Q as well as the financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations included in our Annual Report on Form 10-K, filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2012.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America in Colombia, Argentina, Peru, and Brazil, and we are headquartered in Calgary, Alberta, Canada. Our reportable segments are Colombia, Argentina and Peru. Brazil is not a reportable segment because the level of activity in Brazil is not significant at this time. For the three months ended March 31, 2012, 89% (three months ended March 31, 2011 - 96%) of our revenue and other income was generated in Colombia.

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Highlights

	Three Months Ended March 31, 2012	2011	% Change
Production (BOEPD) (1)	16,742	14,546	15
Prices Realized - per BOE	$101.90	$93.41	9
Revenue and Other Income ($000s)	$155,951	$122,519	27
Net (Loss) Income ($000s)	$(313)	$13,713	(102)
Net (Loss) Income Per Share - Basic	$(0.00)	$0.05	(100)
Net (Loss) Income Per Share - Diluted	$(0.00)	$0.05	(100)
Funds Flow From Operations ($000s) (2)	$78,943	$66,560	19
Capital Expenditures ($000s)	$87,591	$69,103	27

	March 31, 2012	As at December 31, 2011	% Change
Cash & Cash Equivalents ($000s)	$230,076	$ 351,685	(35)
Working Capital (including cash & cash equivalents) ($000s)	$171,505	$ 213,100	(20)
Property, Plant & Equipment ($000s)	$1,069,591	$ 1,044,842	2

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

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

Funds Flow From Operations - Non-GAAP Measure ($000s)	Three Months Ended March 31, 2012	2011
Net (loss) income	$ (313)	$ 13,713
Adjustments to reconcile net (loss) income to funds flow from operations		
DD&A expenses	60,367	63,357
Deferred taxes	(5,250)	(187)
Stock-based compensation	3,192	3,453
Gain on financial instruments	-	(62)
Unrealized foreign exchange loss	21,351	4,458
Settlement of asset retirement obligation	(404)	(4)
Equity tax	-	6,132
Gain on acquisition	-	(24,300)
Funds flows from operations	$ 78,943	$ 66,560

Operational Highlights

- In the first quarter of 2012, oil and natural gas production, NAR and adjusted for inventory changes, averaged 16,742 BOEPD, an increase of 15% over the first quarter of 2011. The increase was due to increased production from the Moqueta and Jilguero fields in Colombia and the Neuquen Basin in Argentina, partially offset by the impact of pipeline disruptions and an increase in pipeline inventory as a result of the change in the sales point in Colombia.

- In Colombia, the Ramiriqui-1 oil exploration well reached total depth at 19,519 feet measured depth (“MD”) in basement. Along with our operating partner Compania Espanola de Petroleos, S.A.U. (“CEPSA”), we completed initial testing on the well with natural flow rates, without pumps, of up to 2,525 BOPD gross over 32.5 hours with a 28/64 inch choke and a 0.12% watercut with 26°API gravity oil from the Mirador formation. The Ramiriqui-1 well flowed at a restricted rate due to gas flaring limitations. We are awaiting approval from the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) of the transfer of our 45% working interest in this Block.

- In Colombia, we completed the Moqueta 3D seismic program with interpretation ongoing to assist in full field development planning.

- In Argentina, we completed drilling and testing the Proa -2 appraisal well, the second well in the Proa oil field. The well went on production in the second quarter of 2012 at a constrained rate of approximately 2,000 BOPD gross to further analyze reservoir performance while additional transportation capacity is evaluated.

- In Brazil, the 3-GTE-03D-BA appraisal well reached a total depth of 2,273 meters MD during the first quarter of 2012 and oil bearing reservoir intervals were encountered. Additionally, a second appraisal well, 3-GTE-4DPA-BA, encountered the Agua Grande formation at 2,065 meters MD and the Sergi formation at 2,182 meters MD.

- In September 2011, we announced two farmout agreements with Statoil do Brasil Ltda. ("Statoil") in a joint venture with PetróleoBrasileiro S.A. ("Petrobras"), in Brazil’s deepwater offshore Camamu-Almada Basin, pursuant to which, we would receive an assignment of a non-operated 10% working interest in Block BM-CAL-7 and a non-operated 15% working interest in Block BM-CAL-10. On February 17, 2012, in accordance with the terms of the farmout agreement, we gave notice to Statoil that we would not enter into and assume our share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farmout agreement has terminated and we will not receive any interest in the block. We paid $23.8 million in the second quarter of 2012 related to our obligation on this farmout agreement.

- During the first quarter of 2012, we received regulatory approval from the ANP in Brazil for the Block BM-CAL-7 farmout agreement and the assignment became effective on April 3, 2012.

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

Financial Highlights

Revenue and other income increased by 27% to $156.0 million in the first quarter of 2012 compared with $122.5 million in the first quarter of 2011 due to increased production and higher oil prices. Average oil and NGL prices realized per bbl in the first quarter of 2012 were $105.36, an increase of 12% compared with $94.31 in the first quarter of 2011.

We incurred a net loss of $0.3 million in the first quarter of 2012, representing basic and diluted net loss per share of $nil. This compares with net income of $13.7 million, or $0.05 per share basic and diluted in the first quarter of 2011. In the first quarter of 2012, increased oil and natural gas sales, reduced impairment charges and no Colombian equity tax expense were more than offset by a $24.4 million foreign exchange loss, the absence of the comparative period gain on acquisition, increased operating, depletion, depreciation and accretion and general and administrative ("G&A") expenses and increased income taxes. Net income in the comparable quarter in 2011 included a gain on the acquisition of Petrolifera Petroleum Limited (“Petrolifera”) of $24.3 million and Colombian equity tax of $8.1 million. The Colombian equity tax is assessed every four years.

Funds flow from operations increased by 19% to $78.9 million in the first quarter of 2012 from $66.6 million in the first quarter of 2011. The increase was primarily due to increased oil and natural gas sales and no Colombian equity tax expense, partially offset by increased operating and G&A expenses.

Cash and cash equivalents was $230.1 million at March 31, 2012 compared with $351.7 million at December 31, 2011. The change in cash and cash equivalents during the first quarter of 2012 was primarily the result of funds flow from operations of $78.9 million and proceeds from issuance of common shares of $0.9 million being more than offset by an increase in net assets from operating activities of $92.4 million, $78.0 million of capital expenditures and a $31.0 million increase in restricted cash during the first quarter of 2012.

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Working capital (including cash and cash equivalents) was $171.5 million at March 31, 2012, a $41.6 million decrease from December 31, 2011.The decrease is a result of a $121.6 million decrease in cash and cash equivalents and a $24.8 million increase in taxes payable due to increased taxable income in Colombia, partially offset by a $76.2 million increase in accounts receivable due to increased sales and the timing of collection of receivables, a $7.2 million increase in inventory due to the new transportation agreement in Colombia and a $21.0 million decrease in accounts payable and accrued liabilities. The decrease in accounts payable and accrued liabilities was primarily the result of a $19.0 million reduction in royalties payable due to the timing of royalty payments and a $13.7 million reduction in VAT payable, partially offset by a $12.0 million increase in capital expenditure related liabilities. Capital expenditure related accounts payable included $23.8 million related to the Block BM-CAL-10 at March 31, 2012.

Property, plant and equipment at March 31, 2012 was $1.1 billion, an increase of $24.7 million from December 31, 2011, as a result of $87.6 million of capital expenditures, partially offset by $62.9 million of depletion, depreciation and impairment expenses.

Business combination

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

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

As indicated in the allocation of the consideration transferred, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, we reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, we recognized a gain on acquisition of $24.3 million in the consolidated statement of operations for the three months ended March 31, 2011. Subsequent to the initial allocation of the consideration in the first quarter of 2011, further assessments of Petrolifera's tax position resulted in a reduction of the gain on acquisition to $21.7 million. The gain reflects the impact on Petrolifera's pre-acquisition market value resulting from their lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

Business Environment Outlook

Our revenues have been significantly affected by the continuing fluctuations in oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about financial markets and the impact of the worldwide economy on oil demand growth. However, based on projected production, prices, costs and our current liquidity position, we believe that our current operations and 2012 capital expenditure program can be maintained from cash flow from existing operations and cash on hand, barring unforeseen events or a downturn in oil and gas prices. Should our operating cash flow decline, we would examine measures such as reducing our capital expenditure program, possible periodic draws from our revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. The continuing uncertainty regarding the Middle East and continued economic instability in the United States and Europe is having an impact on world markets, and we are unable to determine the impact, if any, these events may have on oil prices and demand.

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

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Consolidated Results of Operations

	Three Months Ended March 31,		
	2012	2011	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$155,248	$122,296	27
Interest income	703	223	215
	155,951	122,519	27
Operating expenses	24,487	16,396	49
DD&A expenses	60,367	63,357	(5)
G&A expenses	15,899	13,638	17
Equity tax	-	8,050	-
Financial instruments gain	-	(230)	-
Gain on acquisition	-	(24,300)	-
Foreign exchange loss	24,375	5,199	369
	125,128	82,110	52
Income before income taxes	30,823	40,409	(24)
Income tax expense	(31,136)	(26,696)	17
Net (loss) income	$(313)	$13,713	(102)
Production			
Oil and NGL's, bbl	1,461,404	1,293,453	13
Natural gas, Mcf	372,947	94,317	295
Total production, BOE (1)	1,523,562	1,309,173	16
Average Prices			
Oil and NGL's, per bbl	$105.36	$94.31	12
Natural gas, per Mcf	$3.42	$3.35	2
Consolidated Results of Operations (per BOE)			
Oil and natural gas sales	$101.90	$93.41	9
Interest income	0.46	0.17	171
	102.36	93.58	9
Operating expenses	16.07	12.52	28
DD&A expenses	39.62	48.39	(18)
G&A expenses	10.44	10.42	-
Equity tax	-	6.15	-
Financial instruments gain	-	(0.18)	-
Gain on acquisition	-	(18.56)	-
Foreign exchange loss	16.00	3.97	303
	82.13	62.71	31
Income before income taxes	20.23	30.87	(34)

Income tax expense	(20.44)	(20.39)	-
Net (loss) income	$(0.21)	$10.48	(102)

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

Net loss was $0.3 million, or $nil per share basic and diluted, for the first quarter of 2012 compared with net income of $13.7 million, or $0.05 per share basic and diluted, for the comparable quarter in 2011. In the first quarter of 2012, increased oil and natural gas sales due to increased production and higher realized oil prices, reduced impairment charges and no Colombian equity tax expense were more than offset by a $24.4 million foreign exchange loss, the absence of the comparative period gain on acquisition, increased operating, depletion, depreciation and accretion and G&A expenses and increased income taxes. The Colombian equity tax is assessed every four years. Net income in the comparable quarter in 2011 included a gain on the acquisition of Petrolifera of $24.3 million.

Oil and NGL production, NAR and adjusted for inventory changes, for the first quarter of 2012 increased to 1.5 MMbbl compared with 1.3 MMbbl for the comparable quarter in 2011 primarily due to increased production from the Moqueta and Jilguero fields in Colombia and the addition of the Neuquen Basin in Argentina, from the acquisition of Petrolifera in March 2011. Production during the first quarter of 2012 reflects approximately 26 days of oil delivery restrictions due to three separate disruptions in the Ecopetrol-operated Trans-Andean oil pipeline (“the OTA pipeline”) in Colombia. We continued production at a reduced rate while the OTA pipeline was down, selling a portion of our oil through trucking and storing excess oil, resulting in a reduction in oil production, NAR and adjusted for inventory changes, of approximately 800 BOPD for the first quarter of 2012.

Also, as a result of entering into new oil sales and transportation agreements with Ecopetrol as of February 1, 2012, which changed the sales point of oil from Orito station to Tumaco Port, our reported oil inventory increased representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. This change in sales point and the increase in pipeline inventory had a corresponding one-time reduction in oil production, NAR and adjusted for inventory changes, of approximately 1,040 BOPD for the first quarter of 2012.

Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010 and February 7, 2011 which reduced sales through the OTA pipeline.

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Average realized oil prices in the first quarter of 2012 increased by 12% to $105.36 per bbl from $94.31 per bbl in 2011 reflecting higher oil prices. The average West Texas Intermediate ("WTI") oil price for the first quarter of 2012 was $102.89 per bbl compared with $93.95 per bbl in the comparable quarter in 2011. Average Brent oil price for the first quarter of 2012 was $118.56 per bbl.

Increased production and higher oil prices resulted in a 27% increase in revenue and other income to $156.0 million for the first quarter of 2012 compared with $122.5 million in the comparable quarter in 2011.

Operating expenses for the first quarter of 2012 amounted to $24.5 million, or $16.07 per BOE, compared with $16.4 million, or $12.52 per BOE, in the comparable quarter in 2011. The increase in operating expenses was due to an increase of $3.7 million in Colombia, $3.8 million in Argentina and $0.6 million in Brazil.

DD&A expenses for the first quarter of 2012 decreased to $60.4 million compared with $63.4 million for the comparable quarter in 2011. DD&A expenses for the first quarter of 2012 included a $20.2 million ceiling test impairment in our Brazil cost center. The impairment loss related to seismic and drilling costs on Block BM-CAL-10. The farmout agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period. DD&A expenses for the comparable quarter in 2011 included a $31.9 million ceiling test impairment in our Peru cost center relating to seismic and drilling costs from a dry well.

The remaining increase in DD&A expenses was due to higher production levels and increased future development costs included in the depletable base, partially offset by an increase in reserves. On a BOE basis, DD&A expenses in 2012 were $39.62 compared with $48.39 for 2011, representing an 18% decrease. Excluding the effects of impairment charges, DD&A expenses were $26.36 per BOE in the first quarter of 2012, compared with $24.02 per BOE in the comparable period in 2011.

G&A expenses of $15.9 million for the first quarter of 2012 increased by 17% from $13.6 million in the comparable quarter in 2011 primarily due to a full quarter of Petrolifera G&A expenses and increased employee related costs reflecting the expanded operations in all business segments, partially offset by the absence of $1.2 million of expenses associated with the acquisition of Petrolifera recorded in the first quarter of 2011. G&A expenses per BOE were comparable with the first quarter in 2011 at $10.44 per BOE.

Equity tax in the three months ended March 31, 2011 represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years.

Gain on acquisition of $24.3 million in the three months ended March 31, 2011 related to the Petrolifera acquisition. This gain reflects the impact on Petrolifera's pre-acquisition market value of its lack of liquidity and capital resources required to maintain production and reserves and further develop and explore its inventory of prospects.

Foreign exchange loss of $24.4 million for the first quarter of 2012, of which $21.4 million was an unrealized non-cash foreign exchange loss, primarily represents a foreign exchange loss resulting from the translation of current and deferred tax liabilities in Colombia. In the first quarter of 2011, the foreign exchange loss was $5.2 million, of which $4.5 million was an unrealized non-cash foreign exchange loss. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation results in the recognition of unrealized exchange losses or gains. The Colombian Peso strengthened by 8% and 2% against the U.S. dollar in the three months ended March 31, 2012 and 2011, respectively.

Income tax expense for the first quarter of 2012 was $31.1 million compared with $26.7 million recorded in the comparable quarter in 2011. The increase was primarily due to higher income. For the three months ended March 31, 2012, the effective tax rate was 101% compared with 66% in the comparable quarter in 2011. The change was primarily due to a non-taxable gain on acquisition being recorded in 2011 and an increase in the non-deductible unrealized foreign currency translation loss in 2012. The variance from the 35% U.S. statutory rate for the first quarter of 2012 results from non-deductible foreign currency translation losses and an increase in valuation allowances taken on losses incurred in the U.S., Canada, Argentina, Peru and Brazil. The variance from the 35% U.S. statutory rate for the first quarter of 2011 was primarily attributable to non-deductible foreign currency translation losses as described above and an increase in valuation allowances taken on losses incurred in the U.S., Canada, Argentina, Peru and Brazil, offset partially by the inclusion of the non-taxable gain on acquisition.

2012 Work Program and Capital Expenditure Program

Our capital expenditures during the first quarter of 2012 were $87.6 million (including changes in non-cash working capital) compared with $69.1 million in the comparable quarter in 2011. In 2012, capital expenditures included drilling and acquisition expenditures of $60.7 million, geological and geophysical (“G&G”) expenditures of $22.2 million, facilities expenditures of $2.3 million and other expenditures of $2.4 million.

Our capital program for 2012 has been revised to $444 million from $367 million. This includes $196 million for Colombia, an increase of $14 million due primarily to additional facilities costs on the Garibay and Chaza Blocks and testing of the successful Ramiriqui-1 oil exploration well; $122 million for Brazil, an increase of $54 million due primarily to the acquisition of the remaining 30% working interest in four onshore blocks and associated proportional increase in work program; $47 million for Argentina, a $7 million decrease primarily due to the deferral of drilling in the Santa Victoria block into the first quarter of 2013; and $78 million for Peru, a $16 million increase primarily due to the acquisition costs of an over-riding royalty interest in Block 107; and $1 million associated with corporate activities. Of this, $294 million is for drilling and acquisitions, $58 million is for facilities and pipelines and $92 million is for G&G expenditures. Of the $294 million allocated to drilling and acquisitions, approximately $140 million is for exploration, $43 million is for acquisitions and the balance is for delineation and development drilling.

Our 2012 work program is intended to create both growth and value through strategic acquisitions of working interests, by leveraging existing assets to increase reserves and production levels and through the construction of pipelines and facilities in the areas with proved reserves. We are financing our capital program through cash flows from operations and cash on hand, while retaining financial flexibility with a strong cash position and no debt, so that we can be positioned to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds will be expended as set forth in our 2012 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Excluding potential exploration success, average production in 2012 is expected to range between 20,000 and 21,000 BOEPD NAR.

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Segmented Results – Colombia

	Three Months Ended March 31,		
	2012	2011	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$138,633	$117,304	18
Interest income	204	87	134
	138,837	117,391	18
Operating expenses	16,474	12,785	29
DD&A expenses	32,286	30,036	7
G&A expenses	6,599	3,313	99
Equity tax	-	8,050	-
Foreign exchange loss	23,358	5,321	339
	78,717	59,505	32
Segment income before income taxes	$60,120	$57,886	4
Production			
Oil and NGL's, bbl	1,249,581	1,203,615	4
Natural gas, Mcf	9,474	55,257	(83)
Total production, BOE (1)	1,251,160	1,212,825	3
Average Prices			
Oil and NGL's, per bbl	$110.92	$97.27	14
Natural gas, per Mcf	$3.39	$4.04	(16)
Segmented Results of Operations (per BOE)			
Oil and natural gas sales	$110.80	$96.72	15
Interest income	0.16	0.07	129
	110.96	96.79	15
Operating expenses	13.17	10.54	25
DD&A expenses	25.80	24.77	4
G&A expenses	5.27	2.73	93
Equity tax	-	6.64	-
Foreign exchange loss	18.67	4.39	(325)
	62.91	49.07	28
Segment income before income taxes	$48.05	$47.72	1

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

For the first quarter of 2012, income before income taxes from Colombia amounted to $60.1 million compared with $57.9 million recorded for the comparable quarter in 2011. The increase is mainly due to higher oil sales due to increased production and higher prices and no Colombian equity tax expense, partially offset by increases in operating, DD&A and G&A expenses and foreign exchange losses.

For the first quarter of 2012, production of oil and NGLs, NAR and adjusted for inventory changes, was 1.3 MMbbl, slightly higher than the comparable quarter in 2011 of 1.2 MMbbl. Increased production from new producing wells was offset by the impact of OTA pipeline disruptions and increased inventory due to a change in the sales point. Increases in production resulted from the development of the Moqueta field with six producing wells and production in the Garibay Block from the Jilguero -1 and -2 wells.

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Production during the first quarter of 2012 was affected by approximately 26 days of oil delivery restrictions due to three separate OTA pipeline disruptions. We continued production at a reduced rate while the OTA pipeline was down, selling a portion of our oil through trucking and storing excess oil, resulting in a reduction in oil production, NAR and adjusted for inventory changes, of approximately 800 BOPD for the first quarter of 2012.

Also, as a result of entering into new oil sales and transportation agreements with Ecopetrol as of February 1, 2012, which changed the sales point of produced oil from Orito station to Tumaco Port, our reported oil inventory increased by approximately 121 Mbbl representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. This change in sales point and the increase in pipeline inventory had a corresponding one-time reduction in oil production, NAR and adjusted for inventory changes, of approximately 1,040 BOPD for the first quarter of 2012.

Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010 and February 7, 2011 which reduced sales through the OTA pipeline.

As a result of achieving gross field production of five MMbbl in our Costayaco field in the fourth quarter of 2009, we are subject to an additional government royalty payable. This royalty is calculated on 30% of field production revenue over an inflation adjusted trigger point. That trigger point for Costayaco oil was $32.61 in the first quarter of 2012. Production revenue for this calculation is based on production volumes net of other government royalty volumes. Average government royalties at Costayaco with gross production of 17,000 bbl of oil per day and $100 WTI price per bbl are approximately 27.6%, including the additional government royalty of approximately 20.2%. The ANH sliding scale royalty at 17,000 bbl of oil per day is approximately 9.2% and this royalty is deductible prior to calculating the additional government royalty.

Revenue and other income increased by 18% to $138.8 million in the first quarter of 2012 compared with $117.4 million in the comparable quarter in 2011. Oil and natural gas sales were positively affected by higher net realized oil prices in the first quarter of 2012 and increased production. The average net realized price for oil in the first quarter of 2012 was $110.92 per bbl, an increase of 14% from the comparable quarter in 2011.

Operating expenses for the first quarter of 2012 increased to $16.5 million, or $13.17 per BOE, from $12.8 million, or $10.54 per BOE in the comparable quarter in 2011. Operating expenses per BOE were higher in the first quarter of 2012 due to OTA pipeline oil transportation costs now recorded as operating costs and increased production at Moqueta and Jilguero with higher per BOE operating costs. Under the new sales agreements with Ecopetrol, effective February 1, 2012, our oil sales point moved from Orito to the Port of Tumaco. OTA transportation costs were previously factored into the price we received for oil, but are now invoiced separately and included in operating costs. This is expected to result in an increase in OTA oil transportation costs of $3.49 per bbl. The effect of increased transportation costs was partially offset by a decrease in trucking costs as compared to the same period in 2011. Workover costs were $0.25 per BOE higher than the comparable quarter in 2011 due to increased activity in the Costayaco field.

For the first quarter of 2012, DD&A expenses increased to $32.3 million from $30.0 million in the comparable quarter in 2011 due to higher production levels. DD&A expenses were $25.80 per BOE which was consistent with $24.77 per BOE in the comparable quarter in 2011. Increased costs in our depletable pools were offset by increased reserves.

G&A expenses for the first quarter of 2012 increased to $6.6 million ($5.27 per BOE) from $3.3 million ($2.73 per BOE) in the comparable quarter in 2011. The increase was mainly due to increased salaries and stock-based compensation resulting from an increased headcount and increased consulting fees related to expanded operations and a full quarter of Petrolifera’s G&A expenses.

Equity tax of $8.1 million in the three months ended March 31, 2011 represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. Equity tax is assessed every four years.

The results for the first quarter of 2012 included a foreign exchange loss of $23.4 million, of which $21.4 million was an unrealized non-cash foreign exchange loss on the translation of Colombian peso denominated current and deferred taxes to the U.S. dollar functional currency. For the comparable quarter in 2011, the foreign exchange loss was $5.3 million, of which $4.4 million was unrealized. The Colombian Peso strengthened by 8% and 2% against the U.S. dollar in the first quarter of 2012 and 2011, respectively, resulting in the unrealized foreign exchange loss. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $104,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the first quarter of 2012 were $20.3 million, a decrease of 52% from the comparable quarter in 2011. The following table provides a breakdown of capital expenditures during the first quarter of 2012 and 2011:

	Three Months Ended March 31,	
(Millions of U.S. Dollars)	2012	2011
Drilling and completion	$ 10.5	$ 30.4
Facilities and equipment	1.8	5.1
G&G	7.1	0.9
Other	0.9	5.9
	$ 20.3	$ 42.3

The significant elements of our first quarter 2012 Capital Program in Colombia were as follows:

- Costayaco Field, Chaza Block (100% working interest and operator)

The Costayaco-15 water injector well was spud on January 25, 2012 and reached a total depth of 10,069 feet. This well is intended to assist in maintaining reservoir pressure.

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- Moqueta Field, Chaza Block (100% working interest and operator)

We initiated pre-drilling activities on the Moqueta-7 development well. This well is expected to be drilled from the Moqueta-4 surface location in order to further investigate the down dip limits of the oil columns encountered in the Villeta U, Villeta T and Caballos formation reservoirs. We plan to target the oil water contact with the Moqueta-7 development well, which will either be used as an oil producer or water injector for pressure support depending on the well results.

We completed 3D seismic acquisition over the Moqueta structure and interpretation is ongoing. Combining the results of the Moqueta-7 well with the seismic interpretation will aid in the full field development plan.

- Verdeyaco Field, Guayuyaco Block (70% working interest and operator)

We completed the acquisition of 3D seismic.

- Azar Block (40% working interest and operator)

We commenced civil construction for the La Vega Este-1 oil exploration well.

Outlook - Colombia

The 2012 capital program in Colombia is $196 million with $107 million allocated to drilling, $37 million to facilities and pipelines and $52 million for G&G expenditures.

Our planned work program for the remainder of 2012 in Colombia includes the following:

Exploration Activities

- Together with our partner, we are evaluating options for testing additional reservoir intervals, potentially drilling an appraisal well and implementing an early production program on the Ramiriqui-1 exploration well on the Llanos -22 Block. We are awaiting approval from the ANH of the transfer of our 45% working interest in this Block.

- On the Azar Block, a drilling rig was mobilized to the La Vega Este-1 wellsite. The La Vega Este-1 well is expected to spud in the second quarter of 2012.

- We expect to drill the Bordon-1 oil exploration well on the Garibay Block and the Verdeyaco-1 oil exploration well on the Guayuyaco Block in the second half of 2012.

Development and Delineation Activities

In the Costayaco field, we plan to drill three additional development wells: the Costayaco -7ST water injector well; and two production wells, Costayaco -16 and -17. In the Moqueta field, we plan to drill two development wells: Moqueta -7; and Moqueta -8, a further water injector well. We also plan to drill the Brillante -3 natural gas delineation well in the Sierra Nevada Block.

Facilities and Equipment

Facilities work will include continued electrification of the Moqueta fields, water injection facilities and a production battery at the Jilguero oil discovery.

G&G

G&G work will consist of 3D and 2D seismic planned for the Llanos 22, Chaza, Garibay, Piedemonte Norte, Piedemonte Sur, Putumayo -1 and Putumayo -10 Blocks to mature leads and prospects for drilling in 2013 and beyond.

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Segmented Results – Argentina

	Three Months Ended March 31,		
	2012	2011	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$15,369	$4,992	208
Interest income	47	-	-
	15,416	4,992	209
Operating expenses	7,346	3,547	107
DD&A expenses	5,925	1,147	417
G&A expenses	2,251	918	145
Foreign exchange loss (gain)	371	(190)	295
	15,893	5,422	193
Segment loss before income taxes	$(477)	$(430)	11
Production			
Oil and NGL's, bbl	199,300	89,838	122
Natural gas, Mcf	363,473	39,060	831
Total production, BOE (1)	259,879	96,348	170
Average Prices			
Oil and NGL's, per bbl	$70.87	$54.54	30
Natural gas, per Mcf	$3.42	$2.37	44
Segmented Results of Operations (per BOE)			
Oil and natural gas sales	$59.14	$51.81	14
Interest income	0.18	-	-
	59.32	51.81	14
Operating expenses	28.27	36.81	(23)
DD&A expenses	22.80	11.90	92
G&A expenses	8.66	9.53	(9)
Foreign exchange loss (gain)	1.43	(1.97)	173
	61.16	56.27	9
Segment loss before income taxes	$(1.84)	$(4.46)	(59)

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

For the first quarter of 2012, loss before income taxes in Argentina amounted to $0.5 million compared with $0.4 million in the comparable quarter in 2011. In the first quarter of 2012, increased oil and natural gas sales were more than offset by increased operating, DD&A and G&A expenses and a foreign exchange loss. Results of the Argentina segment were significantly affected by the inclusion of Petrolifera's results. The acquisition of Petrolifera on March 18, 2011, added seven blocks in the Neuquen Basin, including production from four blocks, to the Argentina segment. The impact of Petrolifera on the financial and operational results of the Argentina segment is discussed below.

Oil and NGL production, NAR and adjusted for inventory changes, increased 122% to 0.2 MMbbl for the first quarter of 2012 compared with 0.1 MMbbl for the comparable period in 2011. The increase was due a full quarter of Petrolifera production of 0.1 MMbbl, NAR and adjusted for inventory changes, in the first quarter of 2012 compared with 13 days of post-acquisition Petrolifera production in the comparable quarter.

Natural gas sales NAR relate solely to Petrolifera's properties. Natural gas sales amounted to 0.4 Bcf in the first quarter of 2012.

Overall, total production of oil and gas from the Argentina segment increased by 170% to 0.3 MMBOE in the first quarter of 2012.

Revenue and other income increased by 209% to $15.4 million in the first quarter of 2012 compared with $5.0 million in the comparable quarter in 2011. The increase was primarily due to higher production due to the inclusion of Petrolifera's oil and gas production and increased prices. Average oil prices increased by 30% in the first quarter of 2012 compared with the comparable quarter in 2011.

Due to the Argentine regulatory regime, the average oil price we received for production from our blocks during the first quarter of 2012 was $70.87 per bbl. Currently most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis. We have recently been able to negotiate higher oil prices with refineries as a result of the Argentine government's decision to allow an increase in domestic petroleum product prices.

Operating expenses in the first quarter of 2012 amounted to $7.3 million compared with $3.5 million in the comparable quarter in 2011. Petrolifera's operating expenses were $4.8 million in the first quarter of 2012 compared with $0.6 million in the comparable quarter in 2011. Operating expenses were $28.27 per BOE in the first quarter of 2012 compared with $36.81 per BOE in the comparable quarter in 2011. Workover costs decreased by $2.61 per BOE as a result of more workovers being performed in the comparable quarter in 2011, particularly in the Palmar Largo Block. Other operating costs decreased as a result of a higher percentage of production being from blocks with lower per BOE transportation and operating costs, such as the Puesto Morales Block.

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DD&A expenses in the first quarter of 2012 were $5.9 million compared with $1.1 million in the comparable quarter in 2011. Petrolifera's DD&A expense was $3.6 million in the first quarter of 2012. DD&A expenses per BOE in the first quarter of 2012 were $22.80, significantly higher than DD&A expenses in the comparable quarter of $11.90 due to a reduction of reserves at December 31, 2011.

G&A expenses in the first quarter of 2012 were $2.3 million ($8.66 per BOE) compared with $0.9 million ($9.53 per BOE) in the comparable quarter in 2011. The increase was primarily due to the inclusion of Petrolifera's G&A and increased headcount and consulting fees as a result of expanded operations.

Capital Program - Argentina

Capital expenditures in our Argentine segment during the first quarter of 2012 were $14.1 million, including drilling expenditures of $11.5 million, G&G expenses of $1.4 million, facilities expenses of $0.6 million and other expenditures of $0.6 million. In the comparative quarter in 2011, capital expenditures in our Argentine segment were $11.6 million mainly relating to Valle Morado drilling for $13.5 million, El Chivil facilities for $0.7 million and Santa Victoria expenditures of $0.2 million offset by farmout proceeds of $3.3 million.

The significant elements of our first quarter 2012 Capital Program in Argentina were as follows:

- Surubi Block (85% working interest and operator)

We completed drilling and tested the Proa -2 appraisal well, the second well in the Proa oil field. The successful well encountered approximately 31 meters of net pay in two Palmar Largo intervals. Production tests were performed on the two intervals independently, resulting in combined natural flow rates of 6,300 BOPD gross. The well went on production in the second quarter of 2012 at a constrained rate of approximately 2,000 BOPD gross to further analyze reservoir performance while additional transportation capacity is evaluated.

- Puesto Morales Block (100% working interest and operator)

The PMN-1121 development well spud during December 2011 and is now on production. It reached a total depth of 1,700 meters and encountered oil in the Sierras Blancas and Loma Montosa formations. Flow rate tested at 128 BOPD. We also completed workovers on this Block.

- Rinconada Sur Block (100% working interest and operator)

The R.-1036 development well spud in December 2011 and is now on production. It reached a total depth of 1,200 meters and encountered oil in the Sierras Blancas formation. Flow rate tested at 145 BOPD. The R.x-1059 exploration well spud in January 2012 and reached a total depth of 1,148 meters. The well is currently shut-in for further evaluation.

- Rinconada Norte Block (35% non-operated working interest)

The RN x-1000 and RN x-1001 exploration wells were shut in after reaching total depths of 1,050 meters and 1,250 meters, respectively.

Outlook – Argentina

The 2012 capital program in Argentina is $47 million with $33 million allocated to drilling, $7 million to facilities and pipelines, and $7 million to G&G expenditures.

Our planned work program for the remainder of 2012 in Argentina includes drilling an oil exploration well on each of the Rinconada Sur Block and the Puesto Guevara Block, six gross development wells on the Puesto Morales Block and conducting nine workovers on existing wells in Argentina. The intention of the drilling program is to improve recovery of oil in place and grow production. We also plan to drill and are also evaluating the potential to drill a gas exploration well in the Santa Victoria Block in early 2013.

Segmented Results – Peru

	Three Months Ended March 31,		
	2012	2011	% Change
(Thousands of U.S. Dollars)			
Interest income	$15	$-	-
Operating expenses	$81	$64	26
DD&A expenses	115	31,933	-
G&A expenses	616	565	9
Foreign exchange (gain) loss	(70)	63	(212)
	742	32,625	(98)
Segment loss before income taxes	$(727)	$(32,625)	(98)

DD&A expenses in the first quarter of 2011 included a $31.9 million ceiling test impairment in our Peru cost center relating to seismic and drilling costs related to a dry hole.

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Capital Program – Peru

Capital expenditures in our Peruvian segment during the first quarter of 2012 were $16.7 million, including G&G and acquisition expenses of $14.5 million and other expenditures of $2.2 million. In the comparative quarter, capital expenditures in our Peruvian segment were $14.3 million mainly related to the drilling of Kanatari -1 on Block 128.

The significant elements of our first quarter 2012 Capital Program in Peru were as follows:

- Block 95 (60% working interest and operator)

On January 17, 2012, PeruPetro S.A. signed the assignment documents for Block 95, officially transferring 60% of the block to us. A drilling site location has been identified for the first exploration well on Block 95 and civil construction of a platform and dock facility started in the first quarter of 2012. The block continues to be in Force Majeure.

- Blocks 107 and 133 (100% working interest and operator)

We acquired an over-riding royalty interest in Block 107 that was held by a third party. Permitting for drilling on Block 107 is advancing, with drilling expected to begin in 2013. G&G studies are ongoing on the adjacent Block 133 where we expect to acquire airborne gravity magnetics data this year.

- Blocks 123 and 129 (20% non-operated working interest)

The acquisition of an infill 2D seismic program began in the first quarter of 2012.

Outlook - Peru

The 2012 capital program in Peru is $78 million with $47 million allocated to drilling, $1 million to facilities and pipelines and $30 million for G&G expenditures.

Our planned work program for the remainder of 2012 in Peru includes drilling one gross exploration well on Block 95, pre drilling activities on Block 107 and an infill 2D seismic program for Blocks 123 and 129.

Results - Corporate Activities and Operations in Brazil

	Three Months Ended March 31,		
	2012	2011	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$1,246	$-	-
Interest income	437	136	222
	1,683	136	-
Operating expenses	585	-	-
DD&A expenses	22,041	241	-
G&A expenses	6,434	8,842	(27)
Financial instruments gain	-	(230)	-
Gain on acquisition	-	(24,300)	-
Foreign exchange loss	717	5	-
	29,776	(15,442)	(293)

Segment (loss) income before income taxes	$(28,093)	$15,578	(280)

Corporate activities include costs associated with our headquarters in Calgary, Alberta, Canada, and expenses related to technical reviews, business development and compliance and reporting under securities regulations.

Oil and natural gas sales and operating expenses in the first quarter of 2012 represented sales and operating expense from Block 155 in the onshore Recôncavo Basin of Brazil. We began earning revenue from this block on June 15, 2011, the date regulatory approval was received for the purchase of our 70% participating interest in that block.

DD&A expenses in the first quarter of 2012 of $22.0 million included a ceiling test impairment loss of $20.2 million in our Brazil cost center. The impairment loss related to seismic and drilling costs on Block BM-CAL-10. The farmout agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period. DD&A expense also included $1.6 million of depletion and depreciation in Brazil primarily related to Block 155 which began production mid-2011.

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G&A expenses in the first quarter of 2012 were $6.4 million compared with $8.8 million in the comparable quarter in 2011. In 2011, G&A expenses included $1.2 million related to the acquisition of Petrolifera. In 2012, increases in salary, stock-based compensation expense and consulting charges due to expanded operations, were offset by an increase in the amount of costs recovered from business segments or capitalized in Brazil.

Gain on acquisition in the three months ended 2011 related to the acquisition of Petrolifera. The gain reflected the impact on Petrolifera's pre-acquisition market value of their lack of liquidity and capital resources required to maintain production and reserves and further develop and explore their inventory of prospects.

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

Capital Program – Corporate and Brazil

Capital expenditures in Corporate and Brazil during the first quarter of 2012 were $36.5 million, including $23.8 million paid in relation to Block BM-CAL-10, $11.3 million of drilling expenditures and $1.4 million of other expenditures. In the comparative quarter in 2011, capital expenditures were $0.9 million.

The significant elements of our first quarter 2012 Capital Program in Brazil were as follows:

- Blocks 129, 142, 155 and 224 (70% working interest and operator)

The 3-GTE-03D-BA and 3-GTE-4DPA-BA appraisal wells on Block 155 spud on December 1, 2011 and January 8, 2012. Additionally, we purchased long-lead inventory items for these wells. Pre-drilling activities for the 1-GTE-6-BA exploration well on Block 142 also commenced in the first quarter of 2012.

- BM-CAL-7 Block, Camamu Basin (10% non-operated working interest)

During the first quarter of 2012, we received regulatory approval from the ANP for the Block BM-CAL-7 farmout agreement. Purchase consideration of $0.7 million was paid and the assignment became effective on April 3, 2012.

- BM-CAL-10 Block, Camamu Basin

We recognized $23.8 million of capital expenditures in relation to the Block BM-CAL-10 farmout agreement upon our decision to withdraw from this agreement.

Outlook – Brazil

The 2012 capital program in Brazil is $122 million with $107 million allocated to drilling and acquisition costs, $12 million to facilities and pipelines and $3 million to G&G expenditures.

Our planned work program for the remainder of 2012 in Brazil includes:

- The 3-GTE-03D-BA and 3-GTE-4DPA-BA appraisal wells on Block 155 are expected to be tested and on production in mid-2012. Additionally, we are preparing the necessary ANP documents for the declaration of commerciality and the development plan for the field.

- Also on Block 155, we expect to commence drilling the 1-GTE-5-BA oil exploration well in the second half of 2012.

- On Block 142, drilling of the first horizontal sidetrack well, planned to be drilled from the 1-GTE-01-BA pilot hole, is expected to commence in mid-2012, subject to rig availability. This will be the first of three horizontal sidetrack wells that we expect to drill to test the productivity of the light oil sandstone reservoir targets in the Recôncavo Basin. Completion of the 1-GTE-01-BA well is pending the results of the horizontal leg drilling.

- Additionally, we expect to drill the 1-GTE-6-BA oil exploration well from the 1-GTE-02-BA well bore on Block 129. We anticipate the horizontal sidetrack operations will start in the fourth quarter of 2012, with completion pending the results of the horizontal leg. Completion of the 1-GTE-02-BA well is pending the results of the horizontal leg drilling.

- Planned facilities work includes additional tankage, pipelines and gas facilities on Block 155.

- On January 20, 2012, we entered into a purchase and sale agreement to acquire the remaining 30% participating interest in Blocks 129, 142, 155 and 224 from our partner. The completion of the purchase is subject to ANP approval.

Liquidity and Capital Resources

At March 31, 2012, we had cash and cash equivalents of $230.1 million compared with $351.7 million at December 31, 2011.

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

At March 31, 2012, 79% of our cash and cash equivalents was held by our foreign subsidiaries. This balance is not available to fund domestic operations unless funds are repatriated. We do not intend to repatriate funds, but if we did we would have to accrue and pay taxes.

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Effective July 30, 2010, we established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve based facility has a maximum borrowing base of up to $100 million and is supported by the present value of our Colombian petroleum reserves of two of our subsidiaries with operating branches in Colombia – Gran Tierra Energy Colombia Ltd. and Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. At March 31, 2012 and December 31, 2011, we had not drawn down any amounts under this facility. In February 2012, BNP Paribas announced the sale of its North American reserve based lending business to Wells Fargo Bank NA. This credit facility is expected to be part of that sale. Closing documents are being processed, and the sale is expected to be finalized in the second quarter of 2012.

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

Cash Flows

During the first quarter of 2012, our cash and cash equivalents decreased by $121.6 million as a result of cash used in operating activities of $13.5 million, cash used in investing activities of $109.0 million, partially offset by cash provided by financing activities of $0.9 million.

Cash used in operating activities in the first quarter of 2012 was positively affected by increased production and oil prices; however, these positive contributions were offset by increased operating and G&A expenses and a $92.4 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable increased by $76.2 million due to due to increased sales and the timing of collection of receivables; inventory increased by $7.2 million due to the new transportation agreement in Colombia; accounts payable and accrued liabilities decreased by $21.0 million; partially offset by an increase in taxes payable of $24.8 million due to increased taxable income in Colombia. The decrease in accounts payable and accrued liabilities was due to a $19.0 million reduction in royalties payable due to royalty payments and a $13.7 million reduction in VAT payable, partially offset by a $12.0 million increase in capital expenditure related liabilities. Capital expenditure related accrued liabilities included $23.8 million related to the Block BM-CAL-10 at March 31, 2012.

Cash outflows from investing activities in the first quarter of 2012 included capital expenditures of $78.0 million and an increase in restricted cash of $31.0 million.

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

Off-Balance Sheet Arrangements

As at March 31, 2012, we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of March 31, 2012:

	As at March 31, 2012				
	Payments Due in Period				
	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
(Thousands of U.S. Dollars)					
Oil transportation services	$36,922	$13,072	$7,100	$7,100	$9,650
Drilling and geological and geophysical	58,336	47,086	11,250	-	-
Completions	24,821	19,201	5,620	-	-
Facility construction	41,389	24,557	16,832	-	-
Operating leases	7,661	3,085	3,142	1,434	-
Software and telecommunication	4,790	3,811	979	-	-
Consulting	1,989	1,989	-	-	-
Total	$175,908	112,801	44,923	8,534	9,650

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

At March 31, 2012, we had also provided promissory notes totalling $24.5 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Related Party Transactions

On January 12, 2011, we entered into an agreement to sublease office space to a company of which our President and Chief Executive Officer serves as an independent director. The term of the sublease runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,400 per month plus approximately $5,600 of operating and other expense.

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On August 3, 2010, we entered into a contract related to the Peru drilling program with a company for which one of our directors is a shareholder and director. For the three months ended March 31, 2012, $nil million was incurred and capitalized under this contract (three months ended March 31, 2011 - $2.0 million) and at March 31, 2012, $nil was included in accounts payable related to this contract (December 31, 2011 - $nil).

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

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2011 Annual Report on Form 10-K, filed with the SEC on February 27, 2012, and have not changed materially since the filing of that document.

Item 3 - Quantitative and Qualitative Disclosures About Market risk

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

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

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

Additionally, unrealized foreign exchange gains and losses result from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, monetary liabilities, which are mainly denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $104,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

We consider our exposure to interest rate risk to be immaterial. Our interest rate exposures primarily relate to our investment portfolio. Our investment objectives are focused on preservation of principal and liquidity. By policy, we manage our exposure to market risks by limiting investments to high quality bank issues at overnight rates, or government securities of the United States or Canadian federal governments such as Guaranteed Investment Certificates or Treasury Bills. A 10% change in interest rates would not have a material effect on the value of our investment portfolio. We do not hold any of these investments for trading purposes. We do not hold equity investments, and we have no debt.

Item 4. - Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of March 31, 2012 to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. Legal Proceedings

Gran Tierra is subject to a third party 10% net profits interest on 50% of Gran Tierra’s production from the Chaza Block that arises from the original acquisition in 2006 of 50% of Gran Tierra’s interest in the Chaza Block Contract. There is currently a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party have agreed to resolve this issue through arbitration. An arbitration hearing was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. We now expect to receive the arbitrator’s decision in the second quarter of 2012. 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 disputed amount at March 31, 2012 is $10.9 million. If Gran Tierra is unsuccessful in arbitration this would also increase future net profit interests payable to this third party.