GRAN TIERRA ENERGY, INC.
Form 10-K/A
May 12, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A
(Amendment No. 1)

(Mark One)

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

For the year ended December 31, 2007

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 000-52594

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

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

300, 611 10th Avenue SW
Calgary, Alberta, Canada
(Address of principal executive offices, including zip code)

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

Securities Registered Pursuant to Section 12(b) of the Act: None

Securities Registered Pursuant to Section 12(g) of the Act: Common Stock, par value $0.001 per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

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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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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. (Check one):

Large accelerated filer o Accelerated filer x

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 Exchange Act). Yes o No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second fiscal quarter was approximately $97,771,473 (including 4,126,981 shares issuable upon exercise of exchangeable shares). Aggregate market value excludes an aggregate of 10,098,208 shares of common stock and 11,428,573 shares issuable upon exercise of exchangeable shares held by officers and directors and by each person known by the registrant to own 5% or more of the outstanding common stock on such date. Exclusion of shares held by any of these persons should not be construed to indicate that such person possesses the power, direct or indirect, to direct or cause the direction of the management or policies of the registrant, or that such person is controlled by or under common control with the registrant.

On March 6, 2008, 85,270,058 shares of the registrant's Common Stock, $0.001 par value, and 12,303,966 shares of Gran Tierra Goldstrike Inc., which are exchangeable into our common stock were outstanding, for a total of 97,574,024 shares.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this report, to the extent not set forth herein, is incorporated by reference from the Registrant's definitive proxy statement relating to the 2008 annual meeting of stockholders, which definitive proxy statement was filed with the Securities and Exchange Commission within 120 days after the fiscal year to which this

Report relates.

EXPLANATORY NOTE

We are filing this amendment to our Annual Report on Form 10-K for the year ended December 31, 2007 (the “2007 Form 10-K”) to (1) restate our consolidated financial statements for the years ended December 31, 2007 and 2006, and (2) present restated unaudited quarterly financial information for each of the quarters ended March 31, 2007, June 30, 2007 and September 30, 2007. In the course of preparing our interim financial statements for our quarterly report on Form 10-Q to be filed with the Securities and Exchange Commission (“**SEC**”) for the quarter ended March 31, 2008, we discovered a misclassification of accounts payable and accrued liabilities resulting in a mistatement in cash flows from operating activities with a corresponding offset to cash flows from investing activities in our 2007 interim financial statements for the previously reported quarters ended March 31, 2007, June 30, 2007 and September 30, 2007, and annual financial statements for the years ended December 31, 2006 and 2007 (collectively, the “Affected Financial Statements”). The restatements in the Affected Financial Statements had no effect on our previously reported net change in cash and cash equivalents and no impact on our previously reported consolidated balance sheets or consolidated statements of operations and accumulated deficit contained in the Affected Financial Statements.

The restatement of our consolidated financial statements as a result of the error described above has led our management to conclude that a material weakness existed in our internal control over financial reporting as of December 31, 2007, and that Management’s Report on Internal Control over Financial Reporting should also be restated. Accordingly, this amended filing includes a revised Management Report that reflects management’s conclusion that our internal control over financial reporting was not effective at December 31, 2007. The report of our independent registered public accounting firm was also revised to reflect their conclusion that our internal control over financial reporting was not effective at December 31, 2007.

In accordance with the rules of the SEC, the affected items of the 2007 Form 10-K, “Item 1A Risk Factors” of Part I and “Item 6. Selected Financial Data,” “Item 7. Management’s Discussion of Financial Condition and Results of Operations, ” “Item 8. Financial Statements and Supplementary Data,” and “Item 9A. Controls and Procedures” of Part II, are being amended. No other items, although included herein, have been amended.

No attempt has been made in this Form 10-K/A to update other disclosures presented in the 2007 Form 10-K except as described above or as required to reflect the effects of the restatement. This Form 10-K/A does not reflect events occurring after the filing of the 2007 Form 10-K or modify or update those disclosures, including the exhibits to the 2007 Form 10-K affected by subsequent events; however, this Form 10-K/A includes as Exhibits 31.1, 31.2 and 32 new certifications by our principal executive officer and principal financial officer as required by Rule 12b-15 promulgated under the Securities Exchange Act of 1934, as amended. Accordingly, this Form 10-K/A should be read in conjunction with our filings made with the SEC subsequent to the filing of the 2007 Form 10-K, including any amendments to those filings.

GRAN TIERRA ENERGY INC.

ANNUAL REPORT ON FORM 10-K/A

Year ended December 31, 2007

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PART I

This Annual Report on Form 10-K, particularly in Item 1. "Business", Item 2 "Properties" and Item 7. "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). These statements include, but are not limited to, statements concerning our plans, goals, strategies, intent, beliefs or current expectations. Our actual results could differ materially from those projected in the forward-looking statements as a result of a number of factors, risks and uncertainties discussed in this Form 10-K, especially those contained in Item 1A of this Form 10-K. The words "may," "will," "could," "would," "anticipate," "expect," "intend," "believe," "continue," or the negatives of these terms, or other comparable terminology and similar expressions identify these forward-looking statements. The information included herein is given as of the filing date of this Form 10-K with the Securities and Exchange Commission (SEC) and future events or circumstances could differ significantly from these forward-looking statements. Accordingly, we caution readers not to place undue reliance on these statements. Unless required by law, we undertake no obligation to update publicly any forward-looking statements.

Item 1. *Business*

General

Gran Tierra Energy Inc. and its subsidiaries ("Gran Tierra Energy") is an independent energy company engaged in oil and gas exploration, development and production. We own oil and gas properties in Colombia, Argentina and Peru. A detailed description of our properties can be found under Item 2. "Properties".

Our principal executive offices are located at 300, 611-10th Avenue S.W., Calgary, Alberta, Canada. The telephone number at our principal executive office is (403) 265-3221.

On November 10, 2005, Goldstrike, Inc., a Nevada corporation ("Goldstrike"), Gran Tierra Energy Inc., a privately-held Alberta corporation which we refer to as "Gran Tierra Canada" and the holders of Gran Tierra Canada's capital stock entered into a series of transactions pursuant to which Gran Tierra Canada became a wholly-owned subsidiary of Goldstrike. Immediately following the transactions Goldstrike changed its name to Gran Tierra Energy Inc. and continued operations with the management and business operations of Gran Tierra Canada, but remaining incorporated in the State of Nevada.

In the transactions between Goldstrike and the holders of Gran Tierra Canada common stock, Gran Tierra Canada shareholders received, for their shares of Gran Tierra Canada's common stock: (a) exchangeable shares of a subsidiary of Goldstrike, or (b) shares of Goldstrike common stock, or (c) a combination of exchangeable shares and Goldstrike common stock. Each exchangeable share is exchangeable into one share of our common stock and has the same voting rights as a share of our common stock.

The share exchange between the former shareholders of Gran Tierra Canada and the former Goldstrike is treated as a recapitalization of Gran Tierra Energy for financial accounting purposes. Accordingly, the historical financial statements of Goldstrike before the share purchase and assignment transactions were replaced with the historical financial statements of Gran Tierra Canada before the share exchange in all subsequent filings with the SEC.

Goldstrike was incorporated in the United States on June 6, 2003. Prior to the transactions described above, Goldstrike was engaged in mineral exploration in British Colombia, Canada. Gran Tierra Canada was formed as an Alberta, Canada, corporation in early 2005. The former Gran Tierra Canada was formed by an experienced management team with extensive experience in oil and natural gas exploration and production in most of the world's principal petroleum producing regions.

The Oil and Gas Business

In the discussion that follows, and in Item 2 “Properties”, we discuss our interests in wells and/or acres in gross and net terms. Gross oil and natural gas wells or acres refers to the total number of wells or acres in which we own a working interest. Net oil and natural gas wells or acres is 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 the cost to explore for, develop and produce such oil and natural gas. A working interest owner that owns a portion of the working interest may participate either as operator or by voting his/her percentage interest to approve or disapprove the appointment of an operator and 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 and sales are reported net after deduction of royalties. 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.

Several items that relate to oil and gas operations, specifically seismic operations, are also discussed in this document. 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. Computers 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 miles. A 3-D 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.

Development of Our Business

We made our initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005. During 2006, we acquired oil and gas producing and non-producing assets in Colombia, non-producing assets in Peru and additional properties in Argentina. As a result of these acquisitions we hold:

- 1,191,498 gross acres in Colombia (935,953 net) covering seven Exploration and Production contracts and two Technical Evaluation Areas, three of which are producing and all are operated by Gran Tierra Energy;

- 1,906,418 gross acres (1,488,558 net) in Argentina covering eight Exploration and Production contracts, three of which are producing, and all but one is operated by Gran Tierra Energy; and

- 3,436,040 acres in Peru owned 100% by Gran Tierra Energy, which constitute frontier exploration, in two Exploration and Production contracts operated by Gran Tierra Energy.

In Colombia in 2007, we drilled two discovery wells in the Putumayo Basin, the Juanambu-1 well in the Guayuyaco Block and the Costayaco-1 well in the Chaza Block. We also acquired 70 square kilometers of 3D seismic on the Chaza block, and commenced drilling the Costayaco-2 well, which we completed drilling in January 2008. We drilled four other wells, which were plugged and abandoned. These wells were drilled with partners through various farm-out arrangements, and three of the wells were drilled at no cost to us. We were granted 100% interests in two Technical Evaluation Areas in Colombia in the Putumayo basin - Putumayo West A and Putumayo West B. Finally, we engaged in farm-out activity on several of our exploration blocks, including Mecaya, Rio Magdalena and Talora, and relinquished our interest in the Primavera block.

Plans for 2008 in Colombia focus on the development of the Costayaco discovery. Our plans include drilling a total of six development wells at Costayaco in 2008, including the completion of Costayaco-2 which began drilling in December 2007 and recently completed testing, and Costayaco-3 which entered the testing phase in February, 2008. Along with our drilling operations, we plan to acquire 40 kilometers of 2D seismic on the Chaza block. Also in 2008 we plan to drill one additional development well on the Juanambu discovery, complete one workover and drill one exploration well on the Azar block, drill one exploration well on the Rio Magdalena block and proceed with seismic reprocessing, acquisition and prospect generation on our other blocks and Technical Evaluation Areas. In addition we will be developing production and transportation infrastructure for our producing properties.

In Argentina in 2007, we completed drilling the Puesto Climaco-2 sidetrack well in the El Vinalar block. We also completed several workovers of existing wells designed to maintain production in our other producing fields. In 2008, we plan to complete several workovers to maintain and/or increase production. We also plan to drill one exploration well on our Surubi block.

In Peru, we began acquisition of technical data in 2007 through an aero magnetic-gravity survey, with completion anticipated in the first half of 2008. This will be followed by seismic planning for the remainder of 2008, with acquisition of seismic data planned for 2009.

Our revenues and profit (loss) for each of the last three years, and our total assets as of December 31, 2007 and 2006, are set forth in Item 8 “Financial Statements and Supplementary Data”, which information is incorporated by reference here. Our total assets as of December 31, 2005 were $12.4 million. Our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, which we make available as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC, are available free of charge to the public on our website http://www.grantierra.com. To access our Securities and Exchange Commission (“SEC”) filings, select SEC Filings on the investor relations page on our website, which will link you to the detailed quote for Gran Tierra on the OTC bulletin board site. Click “Filings” to view a list of SEC filings. Our website address is provided solely for informational purposes. We do not intend, by this reference, that our website should be deemed to be part of this Annual Report. Any materials we have filed with the SEC may be read and/or copied at the SEC’s Public Reference Room at 100 F Street N.E. Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding us. The SEC’s website address is www.SEC.gov.

Business Strategy

Our plan is to build an international oil and gas company through acquisition and exploitation of opportunities in oil and natural gas exploration, development and production. Our initial focus is in select countries in South America, currently Argentina, Colombia and Peru.

We are applying a two-stage approach to growth, initially establishing a base of production, development and exploration assets by selective acquisitions, and secondly achieving future growth through drilling. We intend to duplicate this business model in other areas as opportunities arise. We pursue opportunities in countries with prolific petroleum systems and attractive royalty, taxation and other fiscal terms. In the petroleum industry geologic settings with proven petroleum source rocks, migration pathways, reservoir rocks and traps are referred to as prolific petroleum systems.

A key to our business plan is positioning — being in the right place at the right time with the right resources. The fundamentals of this strategy are described in more detail below:

- Position in countries that are welcoming to foreign investment, that provide attractive fiscal terms and/or offer opportunities that we believe have been previously ignored or undervalued.
- Build a balanced portfolio of production, development and exploration assets and opportunities.
- Engage qualified, experienced and motivated professionals.
- Establish an effective local presence.
- Create alliances with companies that are active in areas and countries of interest, and consolidate initial land/property positions.
- Assess and close opportunities expeditiously.

Our access to opportunities stems from a combination of experience and industry relationships of the management team and board of directors, both within and outside of South America. An active market with many available deals is critical to growing a portfolio efficiently and effectively so that we can capitalize on our capabilities today and into the future as we grow in scale and our needs evolve.

Research and Development

We have not expended any resources on pursuing research and development initiatives. We use existing technology and processes for executing our business plan.

Markets and Customers

Ecopetrol S.A., or Ecopetrol, a government agency, is the purchaser of all crude oil sold in Colombia. We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and trucking. Oil from our discoveries at Juanambu and Costayaco is currently being trucked to an entry point of our main pipeline, and construction is underway on gathering systems and pipelines to replace the trucking, which will improve reliability and safety of transportation, as well as increase capacity. The production from our other properties is shipped via pipeline. Crude oil prices are defined by a multi-year contract with Ecopetrol, based on West Texas Intermediate, or WTI, price less adjustments for quality and transportation. Our oil in Colombia is good quality light oil. We receive 25% of our revenue in Colombian pesos, and 75% of revenue in US dollars. Sales to Ecopetrol accounted for 75% of our revenues in 2007, 56% of our revenues in 2006, and 0% of our revenues in 2005.

In accordance with our debt facility with Standard Bank PLC, we are required to hedge a portion of production from our Colombian operations. We entered into a costless collar hedging contract for crude oil based on WTI price, with a floor of $48.00 and a ceiling of $80.00, for a three-year period, for 400 barrels of oil per day from March 2007 to December 2007, 300 barrels of oil per day from January 2008 to December 2008, and 200 barrels of oil per day from January 2009 to February 2010.

We market our own share of production in Argentina. The purchaser of all our oil in Argentina is Refineria del Norte S.A, or Refiner S.A. Our oil in Argentina is good quality light oil and the bulk of our production is transported by pipeline and truck to Refiner S.A., although minor volumes of natural gas and natural gas liquids are sold locally. In Argentina export prices for crude oil are subject to an export tax based on WTI price. An amount equivalent to the export tax is applied to domestic sales, which has the effect of limiting the actual realized price for domestic sales. Our crude oil prices are defined by a contract with Refiner S.A., based on WTI price less adjustments for quality, transportation and an adjustment equivalent to the export tax. We receive revenues in Argentine pesos, based on US dollar prices with the exchange rate fixed on the sales invoice date. Our current contract with Refiner S.A. expired January 1, 2008; however we are continuing sales of our oil under oral agreement with Refiner S.A. See "*Negative Economic, Political and Regulatory Developments in Argentina, Including Export Controls May Negatively Affect our Operation"* in Item 1A "Risk Factors" for a description of the Argentine oil price situation. Sales to Refiner accounted for 25% of our revenues in 2007, 44% of our revenues in 2006, and 100% of our revenues in 2005.

There were no sales in any other country other than Colombia and Argentina in 2007, 2006 and 2005.

See "*Our Oil Sales Will Depend on a Relatively Small Group of Customers, Which Could Adversely Affect Our Financial Results* " and "*Negative Economic, Political and Regulatory Developments in Argentina, Including Export Controls May Negatively Affect our Operations* " in Item 1A "Risk Factors" for a description of the risks faced by our dependency on a small number of customers and the regulatory systems under which we operate.

Competition

The oil and gas industry is highly competitive. We face competition from both local and international companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources that exceed ours, and we believe that these companies have a competitive advantage in these areas. Others are smaller, and we believe our technical and financial capabilities give us a competitive advantage over these companies.

See *"Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business"* and *"Negative Economic, Political and Regulatory Developments in Argentina, Including Export Controls May Negatively Affect our Operations"* in Item IA. "Risk Factors" for risks associated with competition.

Geographic Information

Information regarding our geographic segments, including information on revenues, assets, expenses, income and operating income can be found in Note 4 Segment and Geographic Reporting in Item 8 "Financial Statements and Supplementary Data". Long lived assets are Property, Plant and Equipment, which includes all oil and gas assets, furniture and fixtures, automobiles and computer equipment. No long lived assets are held in our country of domicile, which is the United States of America. Corporate assets include assets held by our corporate head office in Calgary, Alberta, Canada, and assets held in Peru.

Regulation

The oil and gas industry in Colombia, Argentina and Peru is heavily regulated. Rights and obligations with regard to exploration, development and production activities are explicit for each project; economics are governed by a royalty/tax regime. Various government approvals are required for property acquisitions and transfers, including, but not limited to, meeting financial and technical qualification criteria in order to be a certified as an oil and gas company in the country. Oil and gas concessions are typically granted for fixed terms with opportunity for extension.

Colombia

In Colombia, state owned Ecopetrol is responsible for all activities related to exploration, extraction, production, transportation, and marketing oil for export. Historically, all oil production was from concessions granted to foreign operators or undertaken by Ecopetrol under Association Contracts or Shared Risk Contracts with foreign companies which generally provided Ecopetrol with back-in rights, which allow for Ecopetrol to acquire a working interest share in any commercial discovery by paying their share of the costs for that discovery.

Effective January 1, 2004, the regulatory regime in Colombia underwent a significant change with the formation of the Agencia Nacional de Hidrocarbones or National Hydrocarbons Agency, or ANH. The ANH is now responsible for regulating the Colombian oil industry, including managing all exploration lands not subject to a previously existing association contract. The state oil company, Ecopetrol, will maintain its exploration and production activities across the country, but will become a more direct competitor in future projects.

In conjunction with this change, the ANH developed a new exploration risk contract that took effect near the end of the first quarter of 2005. This Exploration and Exploitation Contract has significantly changed the way the industry views Colombia. In place of the earlier association contracts in which the Ecopetrol had an immediate back-in to production, the new agreement provides full risk/reward benefits for the contractor. Under the terms of the contract the successful operator retains the rights to all reserves, production and income from any new exploration block, subject to existing royalty and income tax regulations with a windfall profits tax provision for larger fields.

Argentina

The Hydrocarbons Law 17.319, enacted in June 1967, established the basic legal framework for the current regulation of exploration and production of hydrocarbons in Argentina. The Hydrocarbons Law empowers the National Executive to establish a national policy for development of Argentina's hydrocarbon reserves, with the main purpose of satisfying domestic demand. However, on January 5, 2007, Hydrocarbon Law 26.197 was passed by the Government of Argentina. This new legal framework replaces article one of the Hydrocarbons Law 17.319 and provides for the provinces to assume complete ownership, authority and administration of the crude oil and natural gas reserves located within their territories, including offshore areas up to 12 marine miles from the coast line. This includes all exploration, exploitation and transportation concessions.

On June 3, 2002, the Argentine government issued a resolution authorizing the Energy Secretariat to limit the amount of crude oil that companies can export. The restriction was to be in place from June 2002 to September 2002. However, on June 14, 2002, the government agreed to abandon the limit on crude export volumes in exchange for a guarantee from oil companies that domestic demand will be supplied. Oil companies also agreed not to raise natural gas and related prices to residential customers during the winter months and to maintain gasoline, natural gas and oil prices in line with those in other South American countries.

Recently the Argentine government has issued decrees changing the withholding tax structure and further regulating oil exports. The effects on Gran Tierra Energy are noted in Item 1A. "Risk Factors".

Peru

In Peru, state-controlled Perupetro is responsible for overall regulation and licensing of the oil and gas industry. It also negotiates oil and gas contracts with companies to explore and/or produce in Peru.

See Item 1A. "Risk Factors" for information regarding the regulatory risks that we face.

Environmental Compliance

Our activities are subject to existing laws and regulations governing environmental quality and pollution control in the foreign countries where we maintain operations. Our activities with respect to exploration, drilling and production from wells, facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing crude oil and other products, are subject to stringent environmental regulation by provincial and federal authorities in Colombia, Argentina and Peru. Such regulations relate to environmental impact studies, permissible levels of air and water emissions, control of hazardous wastes, construction of facilities, recycling requirements, reclamation standards, among others. Risks are inherent in oil and gas exploration, development and production operations, and we can give no assurance that significant costs and liabilities will not be incurred in connection with environmental compliance issues. There can be no assurance that all licenses and permits which we may require to carry out exploration and production activities will be obtainable on reasonable terms or on a timely basis, or that such laws and regulations would not have an adverse effect on any project that we may wish to undertake.

In 2007, we experienced a limited number of environmental incidents and enacted many environmental initiatives as follows:

In Colombia, we resolved water contamination issues on our Santana block, and passed government inspection on December 6, 2007. We also dealt with three minor incidents on the Santana block, which caused spilled oil and ground water contamination and a loss to Gran Tierra Energy of approximately 220 barrels of oil. Our pipeline from Miraflor to Santana had several incidents of theft which resulted in minor environmental damage, which was cleaned up and remediated by Gran Tierra Energy. The pipeline incidents caused a loss of approximately 4,166 barrels of oil, net to Gran Tierra Energy. The total cost to Gran Tierra Energy of these incidents was approximately $310,000.

In Argentina, we had one spill of 115 barrels of diesel caused by operator error at our El Vinalar field loading station. The affected area was cleaned, contaminated soil removed and a retaining wall erected around the loading point.

Initiatives enacted in 2007 included implementation of our Corporate Health, Safety and Environment Management System and Environmental Best Practices. We have an Environmental risk management program in place as well as a waste management system. Air and water testing occur regularly, and environmental contingency plans have been prepared for all sites and ground transportation of crude oil. We conducted an internal audit of environmental procedures in December 2007.

During 2006 we spent $95,373 in Colombia to comply with environmental standards around water disposal. In Argentina, we spent $10,400 on environmental monitoring and water disposal.

In Peru, we will conduct an Environmental Impact Assessment, or EIA, on each of our blocks. We expect the costs for 2008 for these EIAs to be approximately $250,000 each.

We will continue compliance with all environmental and pollution control laws and regulations in Colombia, Argentina and Peru. We plan to continue enacting environmental, health and safety initiatives in order to minimize our environmental impact and expenses. We also plan to continue and improve internal audit procedures and practices in order to monitor current performance and search for improvement.

We expect the cost of compliance with Federal, State and local provisions which have been enacted or adopted regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment for the rest of operations will not be material to our company.

Employees

At December 31, 2007, we had 126 full-time employees — 10 located in the Calgary corporate office, 28 in Buenos Aires (15 office staff and 13 field personnel) and 88 in Colombia (24 staff in Bogota and 64 field personnel). None of our employees are represented by labor unions, and we consider our employee relations to be good.

Item 1A. *Risk Factors*

Risks Related to Our Business

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. We will face numerous and varied risks which may prevent us from achieving our goals.

We are a Company With Limited Operating History for You to Evaluate Our Business. We May Never Attain Profitability.

As an oil and gas exploration and development company, which commenced operations in 2005, we have a limited operating history, and therefore it is difficult for potential investors to evaluate our business. Our operations are subject to all of the risks frequently encountered in the development of any new business, including control of expenses and other difficulties, complications and delays, as well as those risks that are specific to the oil and gas industry. Investors should evaluate us in light of the delays, expenses, problems and uncertainties frequently encountered by companies developing markets and operations in new countries. We may never overcome these obstacles. Our accumulated deficit as of December 31, 2007 is $16.5 million.

Our business is speculative and dependent upon the implementation of our business plan and our ability to enter into agreements with third parties for the rights to exploit potential oil and gas reserves on terms that will be commercially viable for us. If we are unable to do so, or unable to do so at the level we intend, then we may never attain profitability.

Unanticipated Problems in Our Operations May Harm Our Business and Our Viability.

If our operations in South America are disrupted and/or the economic integrity of these projects is threatened for unexpected reasons, our business may experience a setback. These unexpected events may be due to technical difficulties, operational difficulties which impact the production, transport or sale of our products, geographic and weather conditions, business reasons or otherwise. Because we are at the early stages of our development, we are particularly vulnerable to these events. Prolonged problems may threaten the commercial viability of our operations. Moreover, the occurrence of significant unforeseen conditions or events in connection with our acquisition of operations in South America may cause us to question the thoroughness of our due diligence and planning process which occurred before the acquisitions, and may cause us to reevaluate our business model and the viability of our contemplated business. Such actions and analysis may cause us to delay development efforts and to miss out on opportunities to expand our operations.

We May Be Unable to Obtain Development Rights We Need to Build Our Business, and Our Financial Condition and Results of Operations May Deteriorate.

Our business plan focuses on international exploration and production opportunities, initially in South America and later in other parts of the world. Thus far, we have acquired interests for exploration and development in eight properties in Argentina, nine properties in Colombia and two properties in Peru. In the event that we do not succeed in negotiating additional property acquisitions, our future prospects will likely be substantially limited, and our financial condition and results of operations may deteriorate.

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

Our business will focus on the oil and gas industry in a limited number of properties, initially in Argentina, Colombia and Peru, with the intention of expanding elsewhere into other countries. Larger companies have the ability to manage their risk by diversification. However, we will lack diversification, in terms of both the nature and geographic scope of our business. As a result, factors affecting our industry or the regions in which we operate will likely impact us more acutely than if our business were more diversified.

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

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

To develop our business, we will endeavor to use the business relationships of our management and board of directors to enter into strategic relationships, which may take the form of joint ventures with other private parties or with local government bodies, or contractual arrangements with other oil and gas companies, including those that supply equipment and other resources that we will use in our business. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

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

The oil and gas industry is highly competitive. Other oil and gas companies will compete with us by bidding for exploration and production licenses and other properties and services we will need to operate our business in the countries in which we expect to operate. This competition is increasingly intense as prices of oil and natural gas on the commodities markets have risen in recent years. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger, foreign owned companies, which, in particular, may have access to greater resources than us, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests.

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

We expect that our cash balances and cash flow from operations and existing credit facility will be sufficient only to provide a limited amount of working capital, and the revenues generated from our properties in Argentina and Colombia will be sufficient only to fund our currently planned operations. We will require additional capital to continue to operate our business beyond our current planned activities and to expand our exploration and development programs to additional properties. We may be unable to obtain additional capital required. Furthermore, inability to obtain capital may damage our reputation and credibility with industry participants in the event we cannot close previously announced transactions.

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

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

If We Fail to Make the Cash Calls Required by Our Current Joint Ventures or Any Future Joint Ventures, We May be Required to Forfeit Our Interests in These Joint Ventures and Our Results of Operations and Our Liquidity Would be Negatively Affected.

If we fail to make the cash calls required by our joint ventures, we may be required to forfeit our interests in these joint ventures, which could substantially affect the implementation of our business strategy. In the future we will be required to make periodic cash calls in connection with our operated and non-operated joint ventures, or we may be required to place funds in escrow to secure our obligations related to our joint venture activity. If we fail to make the cash calls required in connection with the joint ventures, whether because of our cash constraints or otherwise, we will be subject to certain penalties and eventually would be required to forfeit our interest in the joint venture.

We May Not Be Able To Effectively Manage Our Growth, Which May Harm Our Profitability.

Our strategy envisions expanding our business. If we fail to effectively manage our growth, our financial results could be adversely affected. Growth may place a strain on our management systems and resources. We must continue to refine and expand our business development capabilities, our systems and processes and our access to financing sources. As we grow, we must continue to hire, train, supervise and manage new employees. We may not be able to:

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

- allocate our human resources optimally;
- identify and hire qualified employees or retain valued employees; or
- incorporate effectively the components of any business that we may acquire in our effort to achieve growth.

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

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

Our success will depend in large measure on the abilities, expertise, judgment, discretion, integrity and good faith of our management and other personnel in conducting the business of Gran Tierra Energy. We have a small management team consisting of Dana Coffield, our President and Chief Executive Officer, Martin Eden, our Vice President, Finance and Chief Financial Officer, Max Wei, our Vice President, Operations, Rafael Orunesu, our President of Gran Tierra Argentina SA, and Edgar Dyes, our President of Gran Tierra Colombia Ltd. (“Gran Tierra Colombia”). The loss of any of these individuals or our inability to attract suitably qualified staff could materially adversely impact our business. We may also experience difficulties in certain jurisdictions in our efforts to obtain suitably qualified staff and retaining staff who are willing to work in that jurisdiction. We do not currently carry life insurance for our key employees.

Our success depends on the ability of our management and employees to interpret market and geological data successfully and to interpret and respond to economic, market and other business conditions in order to locate and adopt appropriate investment opportunities, monitor such investments and ultimately, if required, successfully divest such investments. Further, our key personnel may not continue their association or employment with Gran Tierra Energy and we may not be able to find replacement personnel with comparable skills. We have sought to and will continue to ensure that management and any key employees are appropriately compensated; however, their services cannot be guaranteed. If we are unable to attract and retain key personnel, our business may be adversely affected.

Risks Related to our Prior Business May Adversely Affect our Business.

Before the share exchange transaction between Goldstrike and Gran Tierra Canada, Goldstrike’s business involved mineral exploration, with a view towards development and production of mineral assets, including ownership of 32 mineral claim units in a property in British Columbia, Canada and the exploration of this property. We have determined not to pursue this line of business following the share exchange, but could still be subject to claims arising from the former Goldstrike business. These claims may arise from Goldstrike’s operating activities (such as employee and labor matters), financing and credit arrangements or other commercial transactions. While no claims are pending and we have no actual knowledge of any threatened claims, it is possible that third parties may seek to make claims against us based on Goldstrike’s former business operations. Even if such asserted claims were without merit and we were ultimately found to have no liability for such claims, the defense costs and the distraction of management’s attention may harm the growth and profitability of our business. While the relevant definitive agreements executed in connection with the share exchange provide indemnities to us for liabilities arising from the prior business activities of Goldstrike, these indemnities may not be sufficient to fully protect us from all costs and expenses.

Maintaining and improving our financial controls may strain our resources and divert management’s attention, and if we are not able to report that we have effective internal controls our stock price may suffer.

We are subject to the requirements of the Securities Exchange Act of 1934, or the Exchange Act, including the requirements of the Sarbanes-Oxley Act of 2002. The requirements of these rules and regulations have increased, and we expect will continue to increase, our legal and financial compliance costs, make some activities more difficult, time-consuming or costly and may also place undue strain on our personnel, systems and resources. The Sarbanes-Oxley Act requires, among other things, that we maintain effective disclosure controls and procedures and internal control over financial reporting. This can be difficult to do. As a result of this and similar activities, management’s attention may be diverted from other business concerns, which could have a material adverse effect on our business, financial condition and results of operations.

We Have a Material Weakness In Our Internal Control Over Financial Reporting, and This Material Weakness Creates a Reasonable Possibility That a Material Misstatement of Our Interim or Annual Financial Statements Will Not Be Prevented or Detected in a Timely Manner.

As a publicly-traded company, we must maintain disclosure controls and procedures and internal control over financial reporting. Our management determined that we have a material weakness in our internal control over financial reporting as of December 31, 2007, relating to the accounting for changes in our accounts payable and accrued liability balances in our statements of cash flow. As a result of this material weaknesses in internal control over financial reporting, material misstatements existed in our statements of cash flow for the years ended December 31, 2007 and 2006, and in our interim financial statements in 2007.

To improve and to maintain the effectiveness of our internal control over financial reporting and disclosure controls and procedures, significant resources and management oversight may be required. As a result of this and similar activities, management's attention may be diverted from other business concerns, which could have a material adverse effect on our business, financial condition and results of operations. If we are unable to remediate the material weakness, or in the future report one or more additional material weaknesses, there is a possibility that this could result in a restatement of our financial statements or impact our ability to accurately report financial information on a timely basis, which could adversely affect our stock price. Further, the presence of one or more material weaknesses could cause us to not be able to timely file our periodic reports with the Securities and Exchange Commission, which could also result in law suits or diversion of management’s attention to our business.

We Must Maintain Effective Registration Statements For All of Our Private Placements of Our Common Stock, and the Restatement of Our Financial Statements Will Require Us to Amend These Registration Statements.

We are required to file Post Effective Amendments to our registration statements periodically in accordance with the Registration Rights Agreements for our 2005 and 2006 private placements of units. As a result of our restatement of our financial statements, we will be required to amend all three registration statements. Amending and keeping these registration statements effective is costly and diverts management’s attention from running our business.

Risks Related to Our Industry

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

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

We May Not Be Able to Develop Oil and Gas Reserves on an Economically Viable Basis, and Our Reserves and Production May Decline as a Result.

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our company's viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and mechanical conditions. While we will endeavor to effectively manage these conditions, we may not be able to do so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

Unless We are Able to Replace Reserves Which We Have Produced, Our Cash Flows and Production will Decrease Over Time.

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

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

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

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

We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated “ceiling”. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices in effect at the time of the calculation are held constant, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense. Under SEC full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings.

Drilling New Wells Could Result in New Liabilities, Which Could Endanger Our Interests in Our Properties and Assets.

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires and spills. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. We will obtain insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

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

We may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which we use for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as “decommissioning.” We have determined that we do not require a significant reserve account for these potential costs in respect of any of our current properties or facilities at this time but if decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our Inability to Obtain Necessary Facilities Could Hamper Our Operations.

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

We are not the Operator of All Our Current Joint Ventures and Therefore the Success of the Projects Held Under Joint Ventures is Substantially Dependent On Our Joint Venture Partners.

As our company does not operate all the joint ventures we are currently involved in, we do not have a direct control over non-operated joint ventures. When we participate in decisions as a joint venture partner, we must rely on the operator’s disclosure for all decisions. Furthermore, the operator is responsible for the day to day operations of the joint venture including technical operations, safety, environmental compliance, relationships with governments and vendors. As we do not have full control over the activities of our non-operated joint ventures, our results of operations for those ventures are dependent upon the efforts of the operating partner.

We May Have Difficulty Distributing Our Production, Which Could Harm Our Financial Condition.

To sell the oil and natural gas that we are able to produce, we have to make arrangements for storage and distribution to the market. We rely on local infrastructure and the availability of transportation for storage and shipment of our products, but infrastructure development and storage and transportation facilities may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. This could be particularly problematic to the extent that our operations are conducted in remote areas that are difficult to access, such as areas that are distant from shipping and/or pipeline facilities. In certain areas, we may be required to rely on only one gathering system, trucking company or pipeline, and, if so, our ability to market our production would be subject to their reliability and operations. These factors may affect our ability to explore and develop properties and to store and transport our oil and gas production and may increase our expenses.

Furthermore, future instability in one or more of the countries in which we will operate, weather conditions or natural disasters, actions by companies doing business in those countries, labor disputes or actions taken by the international community may impair the distribution of oil and/or natural gas and in turn diminish our financial condition or ability to maintain our operations.

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

The entire Argentine domestic refining market is small and export opportunities are limited by available infrastructure. As a result, our oil sales in Argentina will depend on a relatively small group of customers, and currently, on just one customer in the area of our activity in the country. During 2007, we sold all of our production in Argentina to Refiner S.A. The lack of competition in this market could result in unfavorable sales terms which, in turn, could adversely affect our financial results. Currently all operators in Argentina are operating without sales contracts. We cannot provide any certainty as to when the situation will be resolved or what the final outcome will be.

Oil sales in Colombia are made to Ecopetrol, a government agency. While oil prices in Colombia are related to international market prices, lack of competition for sales of oil may diminish prices and depress our financial results.

Drilling Oil and Gas Wells and Production and Transportation Activity Could be Hindered by Hurricanes, Earthquakes and Other Weather-Related Operating Risks.

We are subject to operating hazards normally associated with the exploration and production of oil and gas, including blowouts, explosions, oil spills, cratering, pollution, earthquakes, hurricanes, labor disruptions and fires. The occurrence of any such operating hazards could result in substantial losses to us due to injury or loss of life and damage to or destruction of oil and gas wells, formations, production facilities or other properties.

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

The majority of our oil in Colombia is delivered by a single pipeline to Ecopetrol and sales of oil could be disrupted by damage to this pipeline. Oil from our new discoveries at Costayaco-1 and Juanumbu-1 is trucked a short distance to the entry point of our pipeline, and adverse weather conditions and security issues can cause delays in trucking. Once delivered to Ecopetrol, all of our current oil production in Colombia is transported by an export pipeline which provides the only access to markets for our oil. Without other transportation alternatives, sales of oil could be disrupted by landslides or other natural events which impact this pipeline.

Prices and Markets for Oil and Natural Gas Are Unpredictable and Tend to Fluctuate Significantly, Which Could Reduce Profitability, Growth and the Value of Gran Tierra Energy.

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for WTI in 2000 was $30 per barrel. In 2006, it was $66 per barrel and in 2007 it was $72 per barrel. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Although during 2007 market prices for oil and natural gas have remained at high levels, these prices may not remain at current levels. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differences. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations and quantities of reserves recoverable on an economic basis.

In addition, oil and natural gas prices in Argentina are effectively regulated and as a result are substantially lower than those received in North America. Oil prices in Colombia are related to international market prices, but adjustments that are defined by contract with Ecopetrol, a government agency and the purchaser of all oil that we produce in Colombia, may cause realized prices to be lower than those received in North America.

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

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

Negative Economic, Political and Regulatory Developments in Argentina, Including Export Controls May Negatively Affect our Operations.

The Argentine economy has experienced volatility in recent decades. This volatility has included periods of low or negative growth and variable levels of inflation. Inflation was at its peak in the 1980's and early 1990's. In late-2001 there was a deep fiscal crisis in Argentina involving restrictions on banking transactions, imposition of exchange controls, suspension of payment of Argentina's public debt and abrogation of the one-to one peg of the peso to the dollar. For the next year, Argentina experienced contractions in economic growth, increasing inflation and a volatile exchange rate. Currently, GDP is growing, inflation is normalized, and public finances are strengthened. However, there is no guarantee of economic stability. Any de-stabilization may seriously impact the economic viability of operations in the country or restrict the movement of cash into and out of the country, which would impair current activity and constrain growth in the country.

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

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

Our agreements with Refiner S.A.expired on January 1, 2008, and renegotiation, though currently underway, has been delayed due to the introduction of a new withholding tax regime for crude oil and refined oil products exported and sold domestically in Argentina. Currently all oil and gas producers in Argentina are operating without sales contracts.   The new withholding tax regime was introduced without specific guidance as to its application. Producers and refiners of oil in Argentina have been unable to determine an agreed sales price for oil deliveries to refineries. Also, the price for refiners' gasoline production has been capped below the price that would be received for crude oil. Therefore, the refineries' price offered to oil producers reflects their price received, less taxes and operating costs and their usual mark up. In our case we are receiving $33 per barrel for production since November 18, 2007, the effective date of the decree. The price we received for November oil deliveries before November 18, 2007 was approximately $48 per barrel. Along with most other oil producers in Argentina, we are continuing deliveries to the refinery and will continue to receive $33 per barrel until the situation around the decree is rectified by the government. The Provincial Governments have also been hurt by these changes as their effective royalty take has been reduced by the lower sales price. We are working with other oil and gas producers in the area, as well as Refiner S.A., and provincial governments, to lobby the federal government for change .There has been a delay in rectifying the situation in Argentina because of a change in government in December 2007, and the months of January and February are generally slow working months due to summer vacations.

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

Colombia is among several nations whose progress in stemming the production and transit of illegal drugs is subject to annual certification by the President of the United States. Although Colombia has received a current certification, there can be no assurance that, in the future, Colombia will receive certification or a national interest waiver. The failure to receive certification or a national interest waiver may result in any of the following:

- all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended,

- the Export-Import Bank of the United States and the Overseas Private Investment Corporation would not approve financing for new projects in Colombia,
- United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes, and
- the President of the United States and Congress would retain the right to apply future trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with the Colombian national oil company and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets. Accordingly, the imposition of the foregoing economic and trade sanctions on Colombia would likely result in a substantial loss and a decrease in the price of our common stock. There can be no assurance that the United States will not impose sanctions on Colombia in the future, nor can we predict the effect in Colombia that these sanctions might cause.

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

A 40-year armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups - both funded by the drug trade - continues in Colombia. Insurgents continue to attack civilians and violent guerilla activity continues in many parts of the country.

We, through our acquisition of Argosy Energy International, have interests in three regions of Colombia - in the Middle Magdalena, Llanos and Putumayo regions. The Putumayo region has been prone to guerilla activity in the past. In 1989, Argosy's facilities in one field were attacked by guerillas and operations were briefly disrupted. Pipelines have also been targets, including the Trans-Andean export pipeline which transports oil from the Putumayo region. In addition, in March 2008, one of the Ecopetrol pipelines was blown up by guerillas, and we estimate at present that we will have to reduce our current production and deliveries to Ecopetrol for approximately one week, perhaps longer, while Ecopetrol completes repairs to their pipeline.

There can be no assurance that continuing attempts to reduce or prevent guerilla activity will be successful or that guerilla activity will not disrupt our operations in the future. There can also be no assurance that we can maintain the safety of our operations and personnel in Colombia or that this violence will not affect our operations in the future. Continued or heightened security concerns in Colombia could also result in a significant loss to us.

Increases in Our Operating Expenses will Impact Our Operating Results and Financial Condition.

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

Penalties We May Incur Could Impair Our Business.

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

Environmental Risks May Adversely Affect Our Business.

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

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

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

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

We expect to operate our business in Argentina, Colombia and Peru, and to expand our operations into other countries in the world. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, interference with private contract rights (such as privatization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates and other laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. Central and South America have a history of political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including the imposition of additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Argentina, Colombia, Peru or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

For instance, changes in laws in the jurisdiction in which we operate or expand into with the effect of favoring local enterprises, changes in political views regarding the exploitation of natural resources and economic pressures may make it more difficult for us to negotiate agreements on favorable terms, obtain required licenses, comply with regulations or effectively adapt to adverse economic changes, such as increased taxes, higher costs, inflationary pressure and currency fluctuations.

Local Legal and Regulatory Systems in Which We Operate May Create Uncertainty Regarding Our Rights and Operating Activities, Which May Harm Our Ability to do Business.

We are a company organized under the laws of the State of Nevada and are subject to United States laws and regulations. The jurisdictions in which we operate our exploration, development and production activities may have different or less developed legal systems than the United States, which may result in risks such as:

- effective legal redress in the courts of such jurisdictions, whether in respect of a breach of law or regulation, or, in an ownership dispute, being more difficult to obtain;
- a higher degree of discretion on the part of governmental authorities;
- the lack of judicial or administrative guidance on interpreting applicable rules and regulations;
- inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions; and
- relative inexperience of the judiciary and courts in such matters.

In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for business. These licenses and agreements may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired.

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

We are subject to licensing and permitting requirements relating to drilling for oil and natural gas. We may not be able to obtain, sustain or renew such licenses. Regulations and policies relating to these licenses and permits may change or be implemented in a way that we do not currently anticipate. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations.

Challenges to Our Properties May Impact Our Financial Condition.

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

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

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

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in United States dollars and foreign currencies. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our production is primarily invoiced in United States dollars, but payment is also made in Argentine and Colombian pesos, at the then-current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to United States dollars, our company's functional currency. Since we began operating in Argentina (September 1, 2005), the rate of exchange between the Argentine peso and US dollar has varied between 2.89 pesos to one US dollar to 3.23 pesos to the US dollar, a fluctuation of approximately 11%. Exchange rates between the Colombian peso and US dollar have varied between 2,303 pesos to one US dollar to 2,014 pesos to one US dollar since September 1, 2005, a negative fluctuation of approximately 13%. As currency exchange rates fluctuate, translation of the statements of income of international businesses into United States dollars will affect comparability of revenues and expenses between periods.

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

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

Exchange controls may prevent us from transferring funds abroad. For example, the Argentine government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentine Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentine subsidiaries to make dividend payments to us and there may be a tax imposed with respect to the expatriation of the proceeds from our foreign subsidiaries.

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

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

Risks Related to Our Common Stock

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

The market price of our common stock may be highly volatile and could be subject to wide fluctuations in response to a number of factors that are beyond our control, including:

- dilution caused by our issuance of additional shares of common stock and other forms of equity securities, which we expect to make in connection with future capital financings to fund our operations and growth, to attract and retain valuable personnel and in connection with future strategic partnerships with other companies;

- announcements of new acquisitions, reserve discoveries or other business initiatives by our competitors;

- fluctuations in revenue from our oil and natural gas business as new reserves come to market;

- changes in the market for oil and natural gas commodities and/or in the capital markets generally;
- changes in the demand for oil and natural gas, including changes resulting from the introduction or expansion of alternative fuels; and
- changes in the social, political and/or legal climate in the regions in which we will operate.

In addition, the market price of our common stock could be subject to wide fluctuations in response to:

- quarterly variations in our revenues and operating expenses;
- changes in the valuation of similarly situated companies, both in our industry and in other industries;
- changes in analysts' estimates affecting our company, our competitors and/or our industry;
- changes in the accounting methods used in or otherwise affecting our industry;
- additions and departures of key personnel;
- announcements of technological innovations or new products available to the oil and natural gas industry;
- announcements by relevant governments pertaining to incentives for alternative energy development programs;
- fluctuations in interest rates, exchange rates and the availability of capital in the capital markets; and
- significant sales of our common stock, including sales by future investors in future offerings we expect to make to raise additional capital.

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

Our Operating Results May Fluctuate Significantly, and These Fluctuations May Cause Our Stock Price to Decline.

Our operating results will likely vary in the future primarily from fluctuations in our revenues and operating expenses, including the ability to produce the oil and natural gas reserves that we are able to develop, expenses that we incur, the prices of oil and natural gas in the commodities markets and other factors. If our results of operations do not meet the expectations of current or potential investors, the price of our common stock may decline.

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

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

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Offices

We currently lease office space in: Calgary, Alberta; Buenos Aires, Argentina; and Bogota, Colombia. The two Calgary leases expire January 31, 2011 and January 31, 2013 and cost $12,386 per month and $6,684 per month, respectively. Our two Buenos Aires, Argentina leases expire January 31, 2009 and July 15, 2009 and cost $2,117 per month and $2,467 per month, respectively. Of our three Bogota, Colombia leases, two expire in March 31, 2009 and December 2010, respectively, and one expired on February 29, 2008, with costs of $794, $30,321 and $2,774 per month respectively. The expired lease will not be replaced, as the space is replaced by the lease that expires December 2010. The properties remaining on lease are in excellent condition, and we believe that they are sufficient for our office needs for the foreseeable future.

Oil and Gas Properties-Colombia

In June 2006, we purchased Argosy Energy International L.P (“Argosy”) which was subsequently renamed Gran Tierra Energy Colombia Ltd. Argosy had interests in seven Exploration and Production contracts at that time, including Santana, Guayuyaco, Chaza and Mecaya in the Putumayo basin; Talora and Rio Magdalena in the Magdalena basin; and Primavera in the Llanos basin. The acquisition price included overriding royalty rights and net profits interests in the blocks that were owned by Argosy at the time of the acquisition. The Azar block in the Putumayo basin was acquired later in 2006, and the Putumayo Technical Evaluation Areas in the Putumayo basin were acquired in 2007. We relinquished the Primavera block in 2007.

Currently, the Guayuyaco, Santana and Chaza blocks are producing oil. Oil prices are defined by contract and are related to a WTI reference price. By contract, 25% of sales are denominated in Colombian pesos and 75% in US dollars. Oil is sold to Ecopetrol and is exported via the Trans-Andean pipeline.

Santana

The Santana block covers 1,119 acres and includes 15 producing wells in 4 fields — Linda, Mary, Miraflor and Toroyaco. Activities are governed by terms of a Shared Risk Contract with Ecopetrol, and we are the operator. The properties are subject to a 20% royalty and we hold a 35% interest in all fields with the exception of one well located in the Mary field, Inchiyaco, where we hold a 25.83% working interest, and a third party holds a 9.17% interest. Ecopetrol holds the remaining interest. The block has been producing since 1991. Under the Shared Risk Contract, Ecopetrol initially backed in to a 50% interest upon declaration of commerciality in 1991. In June 1996, when the field reached 7 million barrels of oil produced, Ecopetrol had the right to back into a further 15%, which it took, for a total ownership of 65%.

The production contract expires in 2015, at which time the property will be returned to the government. As a result, there will be no reclamation costs.

In 2007, we performed remedial work on various wells and upgraded the Mary field water processing facility. For 2008, we will continue with regular field maintenance.

Guayuyaco

The Guayuyaco block covers 52,366 acres and includes the area surrounding the four producing fields of the Santana contract area. The Guayuyaco block is governed by an Association Contract with Ecopetrol, resulting in a base royalty of 8%, for production of less than 5,000 barrels of oil per day. The royalty increases in a linear fashion to 20% for production between 5,000 and 125,000 barrels of oil per day, and is stable at 20% up to production of 400,000 barrels of oil per day. For production between 400,000 and 600,000 barrels of oil per day the rate increases again to a maximum of 25%. We are the operator and have a 35% participation interest, and our partners are a third party (35%) and Ecopetrol (30%). The Guayuyaco field was discovered in 2005. Two wells are now producing, with Guayuyaco-1 commencing production in February 2005 and Guayuyaco-2 beginning production in September 2005. A combined 2D and 3D seismic survey was acquired over the block in 2005. Ecopetrol may back-in to a 30% participation interest in any new discoveries in the block.

The contract expires in two phases: the exploration phase and the production phase. The exploration phase expired in 2005 and the production phase expires in 2027. We have completed all of our obligations in relation to the exploration phase of the contract. In March 2007, we completed drilling the Juanambu-1 exploration well and testing was completed in May 2007. Pre-commercial production began in June 2007. Ecopetrol has backed-in with a 30% participation in the discovery, leaving us with a 35% participation interest. Commerciality was granted by Ecopetrol on November 8, 2007. The property will be returned to the government upon expiration of the production contract. As a result, there will be no reclamation costs.

In 2008 we plan to drill a second well on the Juanambu discovery, as well as upgrade facilities and acquire 20 kilometers of 3D seismic, which also extends into the Chaza block.

Rio Magdalena

Argosy entered into the Rio Magdalena Association Contract with Ecopetrol in February 2002. The Rio Magdalena block covers 144,670 acres and is located approximately 75 kilometers west of Bogota, Colombia. This is an exploration block and there are no reserves at this time. We are the operator of the block. According to the terms of the exploration contract, we were committed to drill three exploration wells prior to February 2008. The first of these wells, Popa-1, was drilled in late 2006 and was subsequently plugged and abandoned after testing oil production at non-commercial rates (60 barrels per day). The drilling for the second exploration well, Caneyes-1, began in late December 2006 and the well was subsequently plugged and abandoned in February 2007. We have entered the final exploration phase, which expired February 7, 2008. The contract provides for a 60 day grace period from the date of expiry of the exploration phase in order to remedy any incomplete work commitments. One additional exploration well is planned in satisfaction of our commitment for the final exploration phase The production contract expires in 2030 at which time the property will be returned to the government. As a result, there will be no reclamation costs.

We entered into a commercial agreement with a third party on January 9, 2008 whereby the third party will fund 100% of the additional exploration well, to earn a 60% working interest in the block. The third party will only earn their 60% interest once the obligation to fully fund the exploration well is completed. We will remain operator of the property.

According to the terms of the Association Contract, Ecopetrol may back-in for a 30% participation upon commercialization, and a sliding scale royalty will apply. The base royalty rate is currently 8%, for production less than 5,000 barrels of oil per day, and follows the same sliding scale progression as the Guayuyaco block royalty rates.

Chaza

The Chaza block covers 80,242 acres and is governed by the terms of an Exploration and Exploitation Contract with the government agency ANH. We are the operator and hold a 50% participation interest. The discovery of the Costayaco field in the Chaza Block was the result of drilling the Costayaco-1 exploration well in the second quarter of 2007. This well commenced production in July, 2007. We completed drilling the Costayaco-2 development well on January 2, 2008, and completed casing on January 8, 2008. This well encountered the same reservoir sequences with similar good oil and gas shows as Costayaco-1. Testing of the Costayaco-2 well was completed in February, 2008 and the well bore is currently being completed for production. We commenced drilling Costayaco-3 in January 2008, and completed drilling on February 20, 2008. Costayaco-3 is currently being tested. Four further development wells are planned for 2008, along with facilities and pipeline expansion and 20 kilometers of 3D seismic, which is an extension of the 3D seismic planned for the Guayuyaco block.

The contract for this field expires in two phases. The exploration phase expires in 2011 and the production phase ends in 2032. The property will be returned to the government upon expiration of the production contract. Within sixty days following the date of the return of the property, we must carry out an abandonment program to the satisfaction of ANH. In conjunction with the abandonment, we must establish and maintain an abandonment fund to ensure that financial resources are available at the end of the contract. The base royalty rate is currently 8%, for production less than 5,000 barrels of oil per day, and follows the same sliding scale progression as the Guayuyaco block royalty rates.

Talora

We currently hold a 20% working interest and are the operator for the Talora block. The Exploration and Exploitation Contract associated with the block was originally signed in September 2004, providing for a six year exploration period and 24 year production period. The Talora contract area covers 108,334 acres and is located approximately 75 kilometers west of Bogota, Colombia. This is an exploration block and there are currently no reserves. We commenced drilling the Laura-1 exploration well on December 27, 2006, at no cost to us, and it was subsequently plugged and abandoned in January 2007. Drilling of this well has fulfilled our commitment for the second exploration phase of the contract, which ended December 15, 2006, and which contained a 60 day grace period to remedy incomplete work commitments. The third exploration phase has begun and we have a commitment to drill one well. We entered into a commercial agreement with a third party on December 27, 2007, whereby the third party will pay 100% of our 20% interest in the next exploration well drilled on Talora, in 2008. Once this obligation is fulfilled, we will apply to ANH to have our entire 20% interest in the Talora block assigned to the third party. The property will be returned to the government upon expiration of the production contract.

Primavera

The Primavera Exploration and Exploitation contract was signed May 2006. The Primavera contract area covers 359,064 acres in the Llanos basin. We were the operator and had a 15% participation interest. Chaco Resources also had a 55% participation interest. In 2007, we drilled two wells in the Primavera area at no cost to us. Both wells were dry and were plugged and abandoned. Along with our partners in the field, we decided to relinquish the contract. We have no further obligations in relation to this contract.

Mecaya

The Mecaya Exploration and Exploitation contract was signed June 2006. The Mecaya contract area covers 74,128 acres in southern Colombia, about 150 kilometers southeast of Pasto. We are the operator and currently have a 15% participation interest. The first phase was scheduled to expire June 2007; however, we received a 6 months extension due to extensive consultation required with the local indigenous population. We are currently applying to ANH to have the period extended again, as guerilla activities in the area have prevented us from meeting exploration commitments by the new December, 2007 deadline. On December 27, 2007, we entered into a commercial agreement with a third party whereby the third party will pay us $1,475,000 upon our receipt of an extended work term for the first phase of exploration. Once payment has been received, we will apply to ANH to have our entire 15% interest assigned to the third party. Work plans include 2-D seismic and reprocessing, road construction, plus re-completion of the existing Mecaya-1 well bore. Seismic acquisition began in mid February, 2008. Phase two of the exploration contract expires in 2010. The exploitation phase for this contract expires 24 years after commerciality is approved. The property will be returned to the government upon expiration of the production contract.

Azar

We acquired an 80% interest in the Azar property through a farm-in in late 2006, and were obliged to pay the original owner’s 20% share of future costs, as well as our own 80% share. In mid-2007 we farmed out 50% of our interest to a third party. The third party will pay 100% of our 80% share of exploration and development costs for the first three phases of the exploration contract, and we are obliged to pay 20% of costs under our farm-in agreement. This exploration block covers 51,639 acres. We acquired 40 square kilometers of 3-D seismic at the end of 2007 and beginning of 2008 to assess exploitation opportunities. In 2008 we will drill one well on the property. The exploration contract expires in 2012 for this property. The exploitation phase expires 24 years after commerciality is approved. The property will be returned to the government upon expiration of the production contract. If we make a commercial discovery on the block, and produce oil, we will be obligated to perform abandonment activities, under the same conditions as those for the Chaza block.

Putumayo A&B Technical Evaluation Areas

We were awarded two Technical Evaluation Areas in the Putumayo Basin in southern Colombia in June 2007. The two Technical Evaluation Areas are located near the Orito Field, the largest oil field in the Putumayo Basin.

Putumayo West A covers an area of 230,671 hectares (570,000acres) and is held 100% by Gran Tierra. The evaluation period is 12 months, expiring August 28, 2008. During this time, we have an obligation to conduct 400 kilometres of seismic reprocessing and geologic studies. We will have a preferential right to apply for an Exploration and Exploitation contract in the area during the evaluation stage and match or improve any bid by third parties to convert all or a portion of the Technical Evaluation Area to an exploration license.

Putumayo West B covers an area of 44,111 hectares (109,000 acres) and is held 100% by Gran Tierra. The evaluation period is for 11 months. During this time, we have an obligation to conduct 100 kilometres of seismic reprocessing and geologic studies. We have begun negotiations to convert this Technical Evaluation Agreement to an Exploration and Exploitation contract in the area. If negotiations are successful, the Technical Evaluation Area will be converted to an Exploration and Exploitation contract through the ANH, and the retained acreage would be subject to the new ANH royalty/tax terms which include no additional state participation.

Oil and Gas Properties-Argentina

In September 2005, we entered Argentina through the acquisition of a 14% interest in the Palmar Largo joint venture, and a 50% interest in each of the Nacatimbay and Ipaguazu blocks. In 2006, we purchased further properties in Argentina, including the remaining 50% interest in Nacatimbay and Ipaguzau, a 50% interest in El Vinalar and 100% interests in El Chivil, Valle Morado, Surubi and Santa Victoria. Our Argentina properties are located in the Noroeste Basin in northern Argentina.

Palmar Largo

The Palmar Largo joint venture block encompasses 341,500 acres. This asset is comprised of several producing oil fields in the Noroeste Basin of northern Argentina. We own a 14% working interest in the Palmar Largo joint venture, which we purchased in September 2005. A total of 14 gross wells are currently producing. We produce good quality light oil from this field.

An exploration well was drilled in late 2005 but did not indicate commercial quantities of oil. A portion of the drilling costs for this well was factored into our purchase price for Palmar Largo. Drilling on the Ramon Lista-1001 well was completed in December 2005. Production from the well began in early February 2006 at 299 barrels per day (gross after 12% royalty) or 42 barrels per day net to us. No additional wells were drilled in the area during 2006.

The Palmar Largo block rights expire in 2017 but provide for a ten-year extension. We do not have any outstanding work commitments. At expiry of the block rights, ownership of the producing assets will revert to the provincial government.

Our work program for 2008 involves optimization of well performance and operating expenses to maximize net revenues from the property.

Nacatimbay

We acquired a 100% working interest in the Nacatimbay block through two transactions. We purchased a 50% working interest in September 2005 and we purchased the remaining 50% working interest in November 2006. Production from the Nacatimbay oil, gas and condensate field began in 1996. Three wells were drilled and one was producing until February 28, 2006, when its production was suspended due to low flow conditions. In October 2006, the suspended well was reactivated after surface facilities were upgraded and it produced for two additional months in 2006 and three months of 2007 and is currently shut-in. We continued to explore ways to optimize production in this field during 2007 and explored opportunities to re-enter the Nacatimbay 1001 well.

The Nacatimbay block rights expire in 2022 with a provision for a ten year extension if a discovery is made. We do not have any outstanding work commitments. At expiry of the block rights, ownership of the producing assets will revert to the provincial government.

Ipaguazu

We acquired a 100% working interest in the Ipaguazu block through two transactions. We purchased a 50% working interest in September 2005 and we purchased the remaining 50% working interest in November 2006. The oil and gas field was discovered in 1981 and produced approximately 100 thousand barrels of oil and 400 million cubic feet of natural gas until 2003. No producing activities are carried out in the field at this time. The Ipaguazu block covers 43,243 acres and has not been fully appraised, leaving scope for both reactivation and exploration in the future. The Ipaguazu block rights expire in 2016 with a ten year extension if a discovery is made. We do not have any outstanding work commitments. At expiry of the block rights, ownership of the producing assets will revert to the provincial government. In 2008, we plan to assess the possibility of a workover on the Ipaguazu X-1 well.

El Vinalar

We acquired a 50% working interest in the El Vinalar Block in June 2006. This acquisition added a significant new land position and a small amount of production. El Vinalar covers 248,341 acres and contains a portfolio of exploration leads and oil field enhancement opportunities. The Puesto Climaco-2 sidetrack well was successfully completed in December 2006, and began producing in January 2007.

Plans for 2008 include workovers of three wells - Puesto Climaco 3, Puesto Climaco 1 and El Vinalar 2.

The El Vinalar rights expire in 2016 with a ten year extension if a discovery is made. We do not have any outstanding work commitments. At expiry of the block rights, ownership of the producing assets will revert to the provincial government.

El Chivil, Surubi, Valle Morado, Santa Victoria

We purchased working interests in four additional properties at Chivil, Surubi, Valle Morado and Santa Victoria, in November and December 2006. These properties added to our existing portfolio of exploration and development opportunities and expanded our production base in Argentina. Farm-in partners are being sought to participate in drilling one exploration well on the Surubi block in 2008.

- The Chivil field was discovered in 1987. Three wells were drilled; two remain in production. The field has produced 1.5 million barrels of oil to date. The contract for this field expires in 2015 with the option for a ten year extension.

- Valle Morado was first drilled in 1989. Rights to the area were purchased by Shell in 1998, which subsequently completed a 3-D seismic program over the field and constructed a gas plant and pipeline infrastructure. Production began in 1999 from a single well, and was shut-in in 2001 due to water incursion. We are evaluating opportunities to re-establish production from the field.

- Surubi and Santa Victoria are exploration fields and have no production history.

Oil and Gas Properties — Peru

We entered the Peruvian oil and gas industry in 2006 through the award of two frontier exploration blocks.

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Blocks 122 and 128

We were awarded two exploration blocks in Peru in the last quarter of 2006 under a license contract for the exploration and exploitation of hydrocarbons. Block 122 covers 1,217,651 acres and block 128 covers 2,218,389 acres. The blocks are located in the eastern flank of the Maranon Basin in northern Peru, on the crest of the Iquitos Arch. There is a 5-20%, sliding scale, royalty rate on the lands, dependent on production levels. Production less than 5,000 barrels of oil per day attracts a royalty of 5%, for production between 5,000 and 100,000 barrels of oil per day there is a linear sliding scale between 5% and 20%. Production over 100,000 barrels per day has a royalty of 20%.The exploration contracts expire in 2014 and work commitments are defined in four exploration periods spread over seven years. There is a financial commitment of $5 million over the seven years for each block which includes technical studies, seismic acquisition and the drilling of exploration wells. Acquisition of technical data through aero magnetic-gravity studies began in 2007, and is continuing through the first half of 2008. This will be followed by seismic planning work in 2008 and seismic acquisition 2009. The production contract expires in 2037.

Proved Reserves

No estimates of proved reserves comparable to those included herein have been included in a report to any federal agency other than the SEC.

The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. “Risk Factors”. As a result we have developed internal policies for estimating and evaluating reserves, and 100% of our reserves are audited by an independent reservoir engineering firm at least annually.

The SEC definition of proved oil and natural gas reserves, per Regulation S-X, is as follows:

- *Proved oil and natural gas reserves.* Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made as defined in Rule 4-10(a)(2). Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

b) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

· *Proved developed reserves* — Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods as defined in Rule 4-10(a)(3).

· *Proved undeveloped reserves* — Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required as defined in Rule 4-10(a)(4).

The following table sets forth our proved reserves net of all royalties and third party interests as of December 31, 2007. (all quantities in thousands of barrels of oil)

	Proved Developed Reserves	**Proved Undeveloped Reserves**	**Total Proved Reserves**	**Proved Reserves %**
Colombia				
Santana	661	-	661	10.3%
Guayuyaco	212	-	212	3.3%
Juanambu	206	-	206	3.2%
Costayaco	2,365	905	3,270	51.0%
Mecaya	-	34	34	0.5%
Total Colombia	**3,444**	**939**	**4,383**	**68.3%**
Argentina				
Palmar Largo	381	35	416	6.5%
El Chivil	622	181	803	12.5%
Ipaguazu	296	-	296	4.6%
El Vinalar	520		520	8.1%
Nacatimbay	-	-	-	0.0%
Valle Morado	-	-	-	0.0%
Total Argentina	**1.819**	**216**	**2,035**	**31.7%**
Peru	**-**	**-**	-	-
Total	**5,263**	**1,155**	**6,418**	**100.0%**

Our proved developed reserves set forth in the previous table, totaling 5.3 million barrels of oil as at December 31, 2007 consist of proved developed producing reserves and proved developed non-producing reserves. The following table provides additional information regarding our proved developed reserves at December 31, 2007. (all quantities in thousands of barrels of oil)

	Proved Developed Producing	**Proved Developed Non-Producing**	**Total Proved Developed Reserves**
Colombia			
Santana	609	52	661

Guayuyaco	158	54	212
Juanambu	186	20	206
Costayaco	1,192	1,173	2,365
Mecaya	-	-	-
Total Colombia	**2,145**	**1,299**	**3,444**
Argentina			
Palmar Largo	381	-	381
El Chivil	261	361	622
Ipaguazu	-	296	296
El Vinalar	334	186	520
Nacatimbay	-	-	-
Valle Morado	-	-	-
Total Argentina	**976**	**843**	**1,819**
Total Peru	**-**	**-**	-
Total	**3,121**	**2,142**	**5,263**

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Production Revenue and Price History

Certain information concerning oil and natural gas production, prices, revenues (net of all royalties) and operating expenses for the three years ended December 31, 2007 is set forth in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Drilling Activities

The following table summarizes the results of our development and exploration drilling activity for the past three years. Wells labeled as "In Progress", were in progress as of December 31, 2007.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	2.00	0.85	-	-	1.00	0.35
Dry	4.00	1.50	1.00	1.00		
In Progress	-	-	-	-	-	-
Development						
Productive	-	-	-	-	1.00	0.35
Dry	-	-	-	-	-	-
In Progress	1.00	0.50	-	-	-	-
Total Colombia	7.00	2.85	1.00	1.00	2.00	0.70
Argentina						
Exploration						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	-	-	-	-	-	-
Development						
Productive	1.00	0.50	1.00	0.14	1.00	0.14
Dry	-	-				
In Progress	-	-	-	-	-	-
Total Argentina	1.00	0.50	1.00	0.14	1.00	0.14
Peru						
Exploration						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	-	-	-	-	-	-
Development						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	-	-	-	-	-	-
Total Peru	-	-	-	-	-	-
Total	8.00	3.35	2.00	1.14	3.00	0.84

Following are the results as of February 15, 2008 of wells in progress at December 31, 2007:

	Productive		Dry		Still in Progress	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Colombia	1.00	0.50	-	-	-	-
Argentina	-	-	-	-	-	-
Peru	-	-	-	-	-	-
Total	1.00	0.50				

Well Statistics

The following table sets forth our producing wells as of December 31, 2007.

	Oil Wells		Gas Wells		Total Wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Colombia	19.00	6.71	-	-	19.00	6.71
Argentina	18.00	4.96	1.00	1.00	19.00	5.96
Peru	-	-	-	-	-	-
Total	37.00	11.67	1.00	1.00	38.00	12.67

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2007.

	Developed		Undeveloped		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Colombia	53,485	18,720	1,138,013	917,233	1,191,498	935,953
Argentina[1]	782,089	364,228	1,124,330	1,124,330	1,906,418	1,488,558
Peru	-	-	3,436,040	3,436,040	3,436,040	3,436,040
Total	835,574	382,948	5,698,383	5,477,603	6,533,956	5,860,551

[1] Effective January 1, 2008 we relinquished a total of 271,721 acres in Argentina within existing blocks. No blocks were relinquished in their entirety.

Item 3. ***Legal Proceedings***

Ecopetrol and 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 the 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 benefit of Ecopetrol. There has been no agreement between the parties, and the next step for resolution will be legal proceedings. Gran Tierra Colombia is awaiting further action by Ecopetrol in this regard. At this time no amount has been accrued in the financial statements as we do not consider it probable that a loss will be incurred. The estimated value of disputed production is $2,361,188 which possible loss is shared 50% ($1,180,594) with our partner Solana Petroleum Exploration (Colombia) S.A., with the remaining 50% the responsibility of Gran Tierra Colombia. To our knowledge, no other proceeding against us is currently contemplated by any governmental authority.

Item 4. ***Submission of Matters to a Vote of Security Holders***

At the Annual Meeting of Stockholders of Gran Tierra Energy Inc. held on October 10, 2007, the following proposals were adopted.

Proposal I - To elect the following directors to serve for the ensuing year and until their successors are elected:

	Voted For	Withheld	Broker Non-Votes
Dana Coffield	48,066,859	332,436	¾
Jeffrey Scott	48,065,959	333,336	¾
Walter Dawson	48,046,959	352,336	¾
Verne Johnson	48,045,959	353,336	¾
Nadine C. Smith	48,050,659	348,336	¾

Proposal II - To approve our 2007 Equity Incentive Plan, as an amendment and restatement of our 2005 Equity Incentive Plan, including an increase in the aggregate number of shares of common stock authorized for issuance under the plan from 2,000,000 to 9,000,000 shares:

Voted For	Voted Against	Abstain	Broker Non-Votes
35,614,922	2,282,260	339,050	10,163,063

Proposal III - To ratify the selection by the Audit Committee of Deloitte & Touche LLP as the independent registered public accounting firm of Gran Tierra Energy Inc. for the fiscal year ending December 31, 2007:

Voted For	Voted Against	Abstain	Broker Non-Votes
48,112,897	41,106	245,292	¾

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 28, 2008.

Name	**Age**	**Position**
Dana Coffield	49	President and Chief Executive Officer; Director
Martin H. Eden	60	Chief Financial Officer
Max Wei	58	Vice President, Operations
Rafael Orunesu	52	President, Gran Tierra Energy Argentina
Edgar Dyes	62	President, Argosy Energy/Gran Tierra Energy Colombia

Dana Coffield, President, Chief Executive Officer and Director. Before joining Gran Tierra as President, Chief Executive Officer and a Director in May, 2005, Mr. Coffield led the Middle East Business Unit for EnCana Corporation, North America’s largest independent oil and gas company, from 2003 through 2005. His responsibilities included business development, exploration operations, commercial evaluations, government and partner relations, planning and budgeting, environment/health/safety, security and management of several overseas operating offices. From 1998 through 2003, he was New Ventures Manager for EnCana’s predecessor — AEC International — where he expanded activities into five new countries on three continents. Mr. Coffield was previously with ARCO International for ten years, where he participated in exploration and production operations in North Africa, SE Asia and Alaska. He began his career as a mud-logger in the Texas Gulf Coast and later as a Research Assistant with the Earth Sciences and Resources Institute where he conducted geoscience research in North Africa, the Middle East and Latin America. Mr. Coffield has participated in the discovery of over 130,000,000 barrels of oil equivalent reserves.

Mr. Coffield graduated from the University of South Carolina with a Masters of Science degree and a doctorate (PhD) in Geology, based on research conducted in the Oman Mountains in Arabia and Gulf of Suez in Egypt, respectively. He has a Bachelor of Science degree in Geological Engineering from the Colorado School of Mines. Mr. Coffield is a member of the AAPG and the CSPG, and is a Fellow of the Explorers Club.

Martin H. Eden, Chief Financial Officer. Mr. Eden joined our company as Chief Financial Officer on January 2, 2007. He has over 26 years experience in accounting and finance in the energy industry in Canada and overseas. He was Chief Financial Officer of Artumas Group Inc., a publicly listed Canadian oil and gas company from April 2005 to December 2006 and was a director from June to October, 2006. He has been president of Eden and Associates Ltd., a financial consulting firm, from January 1999 to present. From October 2004 to March 2005 he was CFO of Chariot Energy Inc., a Canadian private oil and gas company. From January 2004 to September 2004, he was CFO of Assure Energy Inc., a publicly traded oil and gas company listed in the United States. From January 2001 to December 2002, he was CFO of Geodyne Energy Inc., a publicly listed Canadian oil and gas company. From 1997 to 2000, he was Controller and subsequently CFO of Kyrgoil Corporation, a publicly listed Canadian oil and gas company with operations in Central Asia. He spent nine years with Nexen Inc. (1986-1996), including three years as Finance Manager for Nexen’s Yemen operations and six years in Nexen’s financial reporting and special projects areas in its Canadian head office. Mr. Eden has worked in public practice, including two years as an audit manager for Coopers & Lybrand in East Africa. Mr. Eden holds a Bachelor of Science degree in Economics from Birmingham University, England, a Masters of Business Administration from Henley Management College/Brunel University, England, and is a member of the Institute of Chartered Accountants of Alberta and the Institute of Chartered Accountants in England and Wales.

Max Wei, Vice President, Operations. Mr. Wei is a Petroleum Engineering graduate from University of Alberta and has twenty-five years of experience as a reservoir engineer and project manager for oil and gas exploration and production in Canada, the US, Qatar, Bahrain, Oman, Kuwait, Egypt, Yemen, Pakistan, Bangladesh, Russia, Netherlands, Philippines, Malaysia, Venezuela and Ecuador, among other countries. Mr. Wei began his career with Shell Canada and later with Imperial Oil, in Heavy Oil Operations. He moved to the US in 1986 to work with Bechtel Petroleum Operations at Naval Petroleum Reserves in Elk Hills, California and eventually joined Occidental Petroleum in Bakersfield. Mr. Wei returned to Canada in 2000 as Team Leader for Qatar and Bahrain operations with AEC International and its successor, EnCana Corporation, where he worked until 2004. He completed a project management position with Petronas in Malaysia in April, 2005, before joining Gran Tierra in May, 2005.

Mr. Wei is specialized in reservoir engineering, project management, production operations, field acquisition and development, and mentoring. He is a registered Professional Engineer in the State of California and a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Wei has a BSc in Petroleum Engineering from the University of Alberta and Certification in Petroleum Engineering from Southern Alberta Institute of Technology.

Rafael Orunesu, Vice President, Latin America. Mr. Orunesu joined Gran Tierra in March 2005 and brings a mix of operations management, project evaluation, production geology, reservoir and production engineering as well as leadership skills to Gran Tierra, with a South American focus. He was most recently Engineering Manager for Pluspetrol Peru, from 1997 through 2004, responsible for planning and development operations in the Peruvian North jungle. He participated in numerous evaluation and asset purchase and sale transactions covering Latin America and North Africa, incorporating 200,000,000 barrels of oil over a five-year period. Mr. Orunesu was previously with Pluspetrol Argentina from 1990 to 1996 where he managed the technical/economic evaluation of several oil fields. He began his career with YPF, initially as a geologist in the Austral Basin of Argentina and eventually as Chief of Exploitation Geology and Engineering for the Catriel Field in the Nuequén Basin, where he was responsible for drilling programs, workovers and secondary recovery projects.

Mr. Orunesu has a postgraduate degree in Reservoir Engineering and Exploitation Geology from Universidad Nacional de Buenos Aires and a degree in Geology from Universidad Nacional de la Plata, Argentina.

Edgar Dyes, President Argosy Energy / Gran Tierra Energy Colombia. Mr. Dyes joined our company through the acquisition of Argosy Energy International L.P., where he was Executive Vice-President and Chief Operating Officer. His experience in the Colombian oil industry spans twenty-one years, with the last six years in charge of Argosy Energy's planning, management, finance and administration activities. Mr. Dyes began his career with Union Texas Petroleum as a petroleum accountant, where he eventually advanced into supervision and management positions in international operations for the company. He subsequently worked for Quintana Energy Corporation; Jackson Exploration, Inc.; CSX Oil and Gas; and Garnet Resources Corporation, where he held the position of Chief Financial Officer. Mr. Dyes has worked in various financial and management roles on projects located in the United Kingdom, Germany, Indonesia, Oman, Brunei, Egypt, Somalia, Ecuador and Colombia. Mr. Dyes holds a Bachelor's degree in Business Management from Stephen F. Austin State University, with postgraduate studies in accounting.

Our above-listed officers and directors have neither been convicted in any criminal proceeding during the past five years nor been parties to any judicial or administrative proceeding during the past five years that resulted in a judgment, decree or final order enjoining them from future violations of, or prohibiting activities subject to, federal or state securities laws or a finding of any violation of federal or state securities law or commodities law. Similarly, no bankruptcy petitions have been filed by or against any business or property of any of our directors or officers, nor has any bankruptcy petition been filed against a partnership or business association in which these persons were general partners or executive officers.

Our board of directors consists of six directors and includes two committees: an audit committee and a compensation committee. We adhere to the Nasdaq Marketplace Rules in determining whether a director is independent and our board of directors has determined that four of our six directors, Messrs. Scott, Johnson and Dawson and Ms. Smith, are "independent" within the meaning of Rule 4200(a)(15) of the NASD's published listing standards.

PART II

Item 5. *Market for Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our common stock was first cleared for quotation on the OTC bulletin board on November 11, 2005 and has been trading since that time under the symbol "GTRE.OB." On February 19, 2008, our common stock was listed on the Toronto Stock Exchange ("TSX") and is trading under the symbol "GTE".

As of March 6, 2008 there were approximately 410 holders of record of shares of our common stock (including holders of exchangeable shares).

On March 6, 2008, the last reported sales price of our shares on the OTC bulletin board was $3.49. For the periods indicated, the following table sets forth the high and low bid prices per share of common stock. These prices represent inter-dealer quotations without retail markup, markdown, or commission and may not necessarily represent actual transactions.

	High	Low
Fourth Quarter 2007	$ 2.69	$ 1.39
Third Quarter 2007	$ 2.16	$ 1.31
Second Quarter 2007	$ 1.49	$ 0.90
First Quarter 2007	$ 1.64	$ 0.88
Fourth Quarter 2006	$ 1.75	$ 1.10
Third Quarter 2006	$ 3.67	$ 1.47

Second Quarter 2006	$	5.01	$	2.96
First Quarter 2006	$	5.95	$	3.02

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As of March 6, 2008, there are 97,574,024 shares of common stock issued and outstanding, which number includes shares of common stock issuable upon exchange of the exchangeable shares of Goldstrike Exchange Co. issued to former holders of common stock of Gran Tierra Energy Inc, a privately held corporation in Alberta ("Gran Tierra Canada").

Dividend Policy

We have never declared or paid dividends on the shares of common stock and we intend to retain future earnings, if any, to support the development of the business and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including current financial condition, operating results and current and anticipated cash needs. Under the terms of our credit facility with Standard Bank Plc, we are required to obtain the approval of the Bank for any dividend payments made by us exceeding $2 million in any fiscal year.

Unregistered Sales of Equity Securities

None.

Performance Graph

Item 6. ***Selected Financial Data***

The following selected financial data should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the consolidated financial statements and the notes thereto included in Item 8. "Financial Statements and Supplementary Data."

	Period Ended December 31,		
	2007	**2006**	**2005**
Statement of Operations Data			
Revenues and other income			
Oil sales	$ 31,807,641	$ 11,645,553	$ 946,098
Natural gas sales	44,971	75,488	113,199
Interest	425,542	351,872	—
Total revenues	32,278,154	12,072,913	1,059,297
Expenses			
Operating	10,474,368	4,233,470	395,287
Depletion, depreciation and accretion	9,414,907	4,088,437	462,119
General and administrative	10,231,952	6,998,804	2,482,070
Liquidated damages	7,366,949	1,527,988	—
Derivative financial instruments	3,039,690	—	—
Foreign exchange (gain) loss	(77,275)	370,538	(31,271)
Total expenses	40,450,591	17,219,237	3,308,205
Loss before income tax	(8,172,437)	(5,146,324)	(2,248,908)
Income tax	(294,767)	(677,380)	29,228
Net loss	$ (8,467,204)	$ (5,823,704)	$ (2,219,680)
Net loss per common share — basic and diluted	$ (0.09)	$ (0.08)	$ (0.16)
Statement of Cash Flows Data	**(As Restated)(1)**	**(As Restated)(1)**	
Operating activities	$ 8,761,439	$ 2,010,056	$ (1,876,638)
Investing activities	(15,392,705)	(48,206,588)	(9,108,022)
Financing activities	719,303	68,075,856	13,206,116
(Decrease) Increase in cash	$ (5,911,963)	$ 21,879,324	$ 2,221,456
Balance Sheet Data			
Cash and cash equivalents	$ 18,188,817	$ 24,100,780	$ 2,221,456
Working capital (including cash)	8,058,049	14,541,498	2,764,643
Oil and gas properties	63,202,432	56,093,284	7,886,914
Deferred tax asset	2,058,436	444,324	—
Total assets	112,796,561	105,536,957	12,371,131
Deferred tax liability	(11,674,744)	(9,875,657)	—

Other long-term liabilities		(1,986,023)		(633,683)		(67,732)
Shareholders' equity	$	(76,791,855)	$	(76,194,779)	$	(11,039,347)

(1) As discussed in Note 13 to our consolidated financial statements, cash flows from operating activities and cash flows from investing activities has been restated as a result of a misclassification of accounts payable and accrued liabilities between the two categories.

We made our initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005 for a total purchase price of approximately $7 million. Prior to that time we had no revenues. In June 2006, we acquired our Argosy assets for consideration of $37.5 million cash, 870,647 shares of our common stock and overriding and net profit interests in certain assets valued at $1 million.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes thereto. Except for the historical information contained herein, the matters discussed below are forward-looking statements that involve risks and uncertainties, including, among others, the risks and uncertainties discussed below.

Overview

We are an independent international energy company involved in oil and natural gas exploration, development and production. We plan to continually increase our oil and natural gas reserves through a balanced strategy of exploration drilling, development and acquisitions in South America. Initial countries of interest are Argentina, Colombia and Peru.

We took our current form on November 10, 2005 when the former Gran Tierra Energy Inc., a privately-held Alberta corporation, which we refer to as Gran Tierra Canada, was acquired by an indirect subsidiary of Goldstrike Inc, a Nevada corporation. Goldstrike adopted the assets, management, business operations, business plan and name of Gran Tierra Canada. For accounting purposes, the predecessor company in the transaction was the former Gran Tierra Canada, and the financial information of the former Goldstrike was eliminated at consolidation. This transaction is accounted for as a reverse takeover of Goldstrike Inc. by Gran Tierra Canada.

Prior to September 1, 2005, we had no oil and gas interests or properties. In September 2005 and during 2006 we acquired oil and gas interests and properties in Argentina, Colombia and Peru.

We funded acquisitions of our properties in Colombia and Argentina through a series of private placements of our securities that occurred between September 2005 and February 2006 and an additional private placement that occurred in June 2006, described below.

Our operating results for the year ended December 31, 2007 as compared to 2006 are principally impacted by the inclusion in 2007 of a full year's activities from the oil and gas interests in Argentina and Colombia we acquired in the second and fourth quarters of 2006. The 2007 results are also impacted by the 2007 discoveries in the Costayaco area of the Chaza block and the Juanambu area of the Guayuyaco block and the subsequent commencement of production of the first wells in each of these areas in the second half of 2007 and a higher average WTI for 2007. Our production volumes and revenues in Colombia have significantly increased over the prior year.

The operating results for 2006 include a full year of activities at Palmar Largo, two months at Nacatimbay before production was suspended on March 1, 2006 and two months after production was reinstated on November 1, 2006, six months of activities at El Vinalar beginning July 1, 2006 and one month of activities at Chivil, commencing December 1, 2006. We initially held a 14% working interest (WI) in Palmar Largo (oil production), a 50% WI in Nacatimbay (production of natural gas and condensate) and a 50% WI in Ipaguazu (exploration land). During November and December of 2006 we acquired the following additional working interests in Argentina, which further impacted the financial and operational results for the year ended December 31, 2007:

· an additional 50% WI in Nacatimbay;

· an additional 50% WI in Ipaguazu;

· 50% WI in El Vinalar (oil production);

· 100% WI in Chivil (oil production);

· 100% WI in Surubi (exploration land);

· 100% WI in Santa Victoria (exploration land); and,

· 93.2% WI in Valle Morado (exploration land).

The operating results for 2006 were also impacted by our acquisition of Argosy Energy International L.P. (“Argosy”). Prior to June 20, 2006 we did not own any oil or gas properties in Colombia. On June 20, 2006 we acquired Argosy and became the operator of nine blocks in Colombia. The Santana, Guayuyaco and Chaza blocks are currently producing. The Rio Magdalena, Talora, Azar and Mecaya blocks are in their exploration phases. During 2007, we relinquished ownership of the Primavera block and acquired the Putumayo A and B technical evaluation areas.

The operating results and financial position for 2005 reflect our incorporation on January 26, 2005 and the commencement of oil and gas operations in Argentina on September 1, 2005.

Due to a successful exploration program in Colombia, undertaken in the first half of 2007, we made two field discoveries, Costayaco in the Chaza block and Juanambu in the Guayuyaco block. These exploration wells were brought into production in the third quarter of 2007 and have significantly increased our daily production. Average daily production in Colombia in 2007, including our new discovery wells Costayaco-1 and Juanambu-1, increased by 559 barrels per day to 913 barrels per day from 354 barrels per day in 2006.

Our estimate of proved reserves, net of royalties, as of December 31, 2007, stands at 6.4 million barrels of oil primarily due to the new discoveries at Costayaco and Juanambu. This compares to our December 31, 2006 proved reserves of 3.0 million barrels of oil.

Effective February 28, 2007, we entered into a credit facility with Standard Bank Plc. The facility has a three-year term which may be extended by agreement between the parties. The borrowing base is the present value of our petroleum reserves up to maximum of $50 million, with an initial borrowing base of $7 million based on mid-2006 reserves. We have not drawn down any amounts under this facility.

In June, 2006, we sold an aggregate of 50 million units of our securities at a price of $1.50 per unit in a private offering for gross proceeds of $75 million, pursuant to four separate Securities Purchase Agreements, which we refer to collectively as the “2006 Offering”. Each unit comprised one share of Gran Tierra Energy’s common stock and one warrant to purchase one-half of a share of Gran Tierra Energy’s common stock at an exercise price of $1.75 for a period of five years. In connection with the issuance of these securities, Gran Tierra Energy entered into four separate Registration Rights Agreements with the investors pursuant to which Gran Tierra Energy agreed to register for resale the shares and warrants (and shares issuable pursuant to the warrants) issued to the investors in the offering by November 17, 2006, and if we failed to do so we would be obligated to pay liquidated damages. The second registration statement was declared effective by the Securities Exchange Commission (“SEC”) on May 14, 2007. Gran Tierra Energy had accrued $8.6 million in liquidated damages as of that date.

On June 27, 2007, under the terms of the Registration Rights Agreements, we obtained a sufficient number of consents from the signatories to the agreements waiving Gran Tierra Energy’s obligation to pay in cash the accrued liquidated damages. We agreed to amend the terms of the warrants issued in the 2006 Offering by reducing the exercise price of the warrants to $1.05 and extending the life of the warrants by one year, in lieu of a cash payment for liquidated damages. $7.4 million of the liquidated damages has been recorded in 2007 and the remainder had been recorded in 2006.

Gran Tierra Energy has an active development drilling and exploration drilling program budgeted for 2008. This includes seven development wells in oil discoveries made in Colombia in 2007 including Costayaco-2 which commenced drilling in December 2007, and completed testing in February 2008; Costayaco-3 which was drilled in January and February 2008 and is planned for testing in March, 2008; and three oil exploration wells, two in Colombia and one in Argentina. Our exploration success in 2007 is to be further developed in 2008 with the potential to significantly increase our production. Gran Tierra Energy plans to continue with development drilling through 2008 to increase our production capacity, in addition to undertaking additional oil exploration efforts to further define the potential of our acreage in Colombia, Argentina and Peru.

Currently all oil and gas producers in Argentina are operating without sales contracts. A new withholding tax regime was introduced in Argentina without specific guidance as to its application. Producers and refiners of oil in Argentina have been unable to determine an agreed sales price for oil deliveries to refineries. We are receiving $33 per barrel, which is a price offered by Refiner S.A., the purchaser of our crude oil, based on their netback, for production since November 18, 2007, the effective date of the decree. The price we received for November oil deliveries before November 18, 2007 was approximately $48 per barrel. Along with most other oil producers in Argentina, we are continuing deliveries to the refinery and will continue to receive $33 per barrel until the situation around the decree is rectified by the government. The Provincial Governments have also been hurt by these changes as their effective royalty take has been reduced by the lower sales price. We are working with other oil and gas producers in the area, as well as Refiner S.A. and provincial governments, to lobby the federal government for change. There has been a delay in rectifying the situation in Argentina because of a change in government in December 2007, and the months of January and February are generally slow working months due to summer vacations.

Operating in countries in South America exposes our business to risks due to political and economic forces in the countries in which we operate. For example, in March 2008, one of the Ecopetrol pipelines was blown up by guerillas, and we estimate at present that we will have to reduce our current production deliveries to Ecopetrol for approximately one week, perhaps longer, while Ecopetrol completes repairs to their pipeline, which will impact our revenues for the first quarter of 2008. See Item 1A. “Risk Factors” for the risks we face as a result of operating in South America.

Results of Operations for the years ended December 31, 2007 as compared to year ended December 31, 2006

Revenue and Other Income

A summary of selected production, revenue and price information for the years ended December 31, 2007 and 2006 is presented in the following table:

	Year Ended December 31,								
	2007			2006			Change from Prior Year		
	Argentina	Colombia	Total	Argentina	Colombia	Total	Argentina	Colombia	Total
Production, net of royalties (2)									
Oil and NGLs (Bbls)	207,912	333,157	541,069	127,712	129,209	256,921	63%	158%	111%
Gas (Mcf)	26,631	-	26,631	41,447	-	41,447	-36%	-	-36%
Oil, Gas and NGLs (Boe) (1)	209,244	333,157	542,401	129,784	129,209	258,993	61%	158%	109%
Revenue and other income									
Oil and NGLs (Bbls)	$ 8,059,486	$ 23,748,155	$ 31,807,641	$ 5,033,363	$ 6,612,190	$ 11,645,553	60%	259%	173%
Gas	44,971	-	44,971	75,488	-	75,488	-40%	-	-40%
Interest (excluding Corporate)	15,225	222,785	238,010	-	-	-	100%	100%	100%
	$ 8,119,682	$ 23,970,940	$ 32,090,622	$ 5,108,851	$ 6,612,190	$ 11,721,041	59%	263%	174%
Other - Corporate			187,532			351,872			-47%
			$ 32,278,154			$ 12,072,913			167%
Average Prices									
Oil and NGLs (Per Bbl)	$ 38.76	$ 71.28	$ 58.79	$ 39.41	$ 51.17	$ 45.33	-2%	39%	30%
Gas (Per Mcf)	$ 1.69	-	$ 1.69	$ 1.82	-	$ 1.82	-7%	-	-7%

(1) Gas volumes are converted to barrels (“bbl’s”) of oil equivalent ("Boe") at the rate of 20 thousand cubic feet ("Mcf") of gas per barrel of oil based upon the approximate relative values of natural gas and oil. Natural Gas Liquids (NGLs") volumes are converted to Boe’s on a one-to-one basis with oil.

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

Crude oil and NGL production for the year ended December 31, 2007 increased 111% to 541,069 barrels from 256,921 barrels for the year ended December 31, 2006. The average price received per barrel of oil increased 30% to $58.79 per barrel for 2007 from $45.33 per barrel in 2006. As a result, revenues and other income for the year ended December 31, 2007 increased 167% to $32,278,154 compared to $12,072,913 for the year ended December 31, 2006. The increase in production is due primarily to the inclusion of a full year of Colombian and Argentine production and the commencement of production at the beginning of the third quarter from the two new discovery wells. The 2006 production included Colombian production subsequent to its acquisition in June 2006. In Argentina, the 2006 results include a full year of activities at Palmar Largo, four months at Nacatimbay, six months of activities at El Vinalar beginning July 1, 2006, and one month of activities at Chivil, commencing December 1, 2006. Natural gas production in 2007 decreased 36% to 26,631 Mcf from 41,447 Mcf in 2006 with the average price also decreasing 7% to $1.69 per Mcf from $1.82 per Mcf. The volume decrease was a result of an operations decision to use the gas production for operating power generation and market only the unused excess.

In Argentina, crude oil and NGL production after 12% royalties for the year ended December 31, 2007 increased 63% to 207,912 barrels compared to 127,712 barrels for 2006. This increased production includes 89,361 barrels from Palmar Largo, 77,971 barrels from El Vinalar and 40,039 barrels from Chivil. Average daily production for the year was 245 barrels from Palmar Largo, 214 barrels from El Vinalar and 110 barrels from Chivil. Natural gas production, after royalties of 12%, at Nacatimbay in 2007 was 26,631 Mcf as compared to 41,447 Mcf in 2006. For 2006, Argentina's crude oil production after 12% royalties was 127,712 barrels, including 118,121 barrels from Palmar Largo, 7,644 barrels from El Vinalar for the period July 1 to December 31, 2006, and 1,947 barrels from Chivil for December 1 to December 31, 2006. Average daily production for these periods in 2006 was 324 barrels from Palmar Largo, 42 barrels from El Vinalar (21 barrels per day for the year) and 63 barrels (5 barrels per day for the year) from Chivil.

In Argentina, net revenue for the year ended December 31, 2007, after deducting royalties at an average royalty rate of 12% of production revenue, and after deducting turnover taxes, increased 60% to $8,059,486 ($38.76 per barrel) for oil and NGLs and decreased 40% to $44,971 ($1.69 per Mcf) for natural gas as compared to $5,033,363 ($39.41 per barrel) and $75,488 ($1.82 per Mcf), respectively, for 2006. Oil and natural gas prices are effectively regulated in Argentina. Although production from most properties has increased due to a full year's production in 2007 as compared to 2006, domestic prices received have decreased due to the impact of increased export taxes levied by the Federal Government.

In Colombia, crude oil and NGL production, after government royalties ranging from 8% to 20% and a third party two percent overriding royalty, for the year ended December 31, 2007 increased 158% to 333,157 barrels as compared to 129,209 barrels for 2006. This increased production includes 112,662 barrels from the Santana block, 60,533 barrels from the Guayuyaco block (excluding the Juanambu area), 38,119 barrels from the Juanambu area and 125,163 barrels from the Chaza block (Costayaco area). The average daily production for the year was 309 barrels per day from the Santana block, 166 barrels per day from the Guayuyaco block (excluding the Juanambu area), and 104 barrels per day from the Juanambu area and 343 per day from the Chaza block. For 2006, Colombia's production and results of operations commenced June 21, 2006 in conjunction with our acquisition of Argosy. Production after royalties was 129,209 barrels for the period from June 21 to December 31, 2006, comprising 65,176 barrels from the Santana block and 64,033 barrels from the Guayuyaco block, representing a combined average production rate of 692 barrels per day for the period (354 barrels per day for the year). The significant increase is as result of a full year of production and two new discoveries, one in the Juanambu area of the Guayuyaco block and the other in the Costayaco area of the Chaza block which came on production in the third quarter of 2007.

In Colombia, crude oil and NGL revenue, net of royalties, for the year ended December 31, 2007 increased 259% to $23,748,155 or $71.28 per barrel as compared to $6,612,190 and $51.17 per barrel for 2006. Besides the increase in production as a result of the new discovery wells and a full year of production from the other areas, revenue increased due to the increased price of oil received based on a higher WTI price in 2007.

Interest income earned on our cash deposits for the year ended December 31, 2007 increased 21% to $425,542 as compared to $351,872 for 2006. Although our cash balances held by corporate from funds raised mid-year 2006 through private placements have decreased, the increase in receipts from crude oil sales throughout 2007 has offset this decrease, resulting in an increase in interest revenue.

Operating Expenses

	Year Ended December 31,								
	2007			2006			Change from Prior Year		
	Argentina	Colombia	Total	Argentina	Colombia	Total	Argentina	Colombia	Total
Operating Expense									
Operating Expense	$ 6,327,276	$ 4,097,336	$ 10,424,612	$ 2,846,705	$ 1,386,765	$ 4,233,470	122%	195%	146%
Other - Corporate - Peru Operations			49,756			-			100%
	$ 6,327,276	$ 4,097,336	$ 10,474,368	$ 2,846,705	$ 1,386,765	$ 4,233,470			147%
Operating expense per Boe	$ 30.24	$ 12.30	$ 19.31	$ 21.93	$ 10.73	$ 16.35	38%	15%	18%

For the year ended December 31, 2007, operating expenses increased 147% to $10,474,368 ($19.31 per Boe) compared to $4,233,470 ($16.35 per Boe) in 2006, reflecting the inclusion in 2007 of a full year of Colombian and Argentine operating activities for those properties. The operations for the new discovery wells at Juanambu and Costayaco commenced in the third quarter of 2007 contributing to the increase in operating costs. In 2006, Argentina's operations included a full year operations at Palmar Largo, four months at Nacatimbay, six months of activities at El Vinalar and one month at Chivil. Colombia's operations commenced June 21, 2006 as a result of the purchase of Argosy.

In Argentina, operating expenses for 2007 increased 122% to $6,327,276 ($30.24 per Boe) as compared to $2,846,705 for 2006 ($21.93 per Boe). The 2007 operating costs are higher than in 2006 due to workovers undertaken in 2007. Argentina's 2007 operating costs include $9.71 per Boe ($2.27 per Boe in 2006) of costs associated with budgeted workover projects undertaken to sustain production.

In Colombia, operating expenses increased 195% to $4,097,336 in 2007 ($12.30 per Boe) as compared to $1,386,765 for the period June 21 to December 31, 2006 ($10.73 per Boe). The 2007 operating costs included $2.69 per Boe ($4.11 per Boe in 2006) of budgeted workover expense mainly carried out in the Guayuyaco block.

Depletion, Depreciation and Accretion ("DD&A")

	Year Ended December 31,	
	2007	2006

	Argentina	Colombia	Total	Argentina	Colombia	Total	Change from Prior Year Argentina	Colombia	Total
DD&A									
DD&A	$ 2,476,834	$ 6,850,086	$ 9,326,920	$ 1,550,544	$ 2,494,317	$ 4,044,861	60%	175%	131%
Other - Corporate			87,987			43,576			102%
			$ 9,414,907			$ 4,088,437			130%
DD&A per Boe	$ 11.84	$ 20.56	$ 17.36	$ 11.95	$ 19.30	$ 15.79	-1%	7%	10%

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Depreciation, depletion and accretion for the year ended December 31, 2007 increased 130% to $9,414,907 from $4,088,437 for 2006. For Argentina, DD&A increased 60% to $2,476,834 from $1,550,544 in 2006. The increase in Argentina is mainly due to decreased proved reserves offset by a decreasing proved depletable cost base resulting in an 1% decrease of the DD&A rate to $11.84 per Boe in 2007 from $11.95 per Boe in 2006. This decreasing proved depletable cost base is a result of the mature nature of the properties held and our 2007 focused capital spending on the Colombian exploration program.

For Colombia, DD&A increased 175% to $6,850,086 from $2,494,317 for 2006. The increase in Colombia is primarily due to the increase in production over the prior year. Though our Colombian proved reserves increased significantly in 2007, Gran Tierra Energy also invested much of its 2007 capital spending on the Colombia exploration program. As a result, our Colombian proved depletable cost base has significantly increased resulting in a 2007 depletion rate of $20.56 per Boe as compared to $19.30 per Boe for 2006.

The 2006 DD&A includes a full year of operations at Palmar Largo, additional Argentina acquisitions in 2006, and the inclusion of Colombia operations in June 2006.

General and Administrative ("G&A")

	Year Ended December 31,								
		2007			2006		Change from Prior Year		
	Argentina	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**
G&A									
G&A	$ 1,704,410	$ 1,695,825	$ 3,400,235	$ 1,122,980	$ 897,494	$ 2,020,474	52%	89%	68%
Other - Corporate			$ 6,831,717			$ 4,978,330			37%
			$ 10,231,952			$ 6,998,804			46%
G&A per Boe	$ 8.15	$ 5.09	$ 18.86	$ 8.65	$ 6.95	$ 27.02	-6%	-27%	-30%

General and administrative costs for the year ended December 31, 2007 increased 46% to $10,231,952 from $6,998,804 for 2006. The increase in G&A was due to the inclusion of a full year of business activities related to the acquisition of the Argosy properties in Colombia and additional properties in Argentina, corporate stewardship costs including Sarbanes Oxley compliance, securities registration related costs and increased stock compensation due to increased option grants. Argentina's G&A cost for the year ended December 31, 2007 increased 52% to $1,704,410 from $1,122,980 in 2006 as a result of the need for increased administration staff and professional costs associated with properties purchased late in 2006. Colombia's G&A for the year ended December 31, 2007 increased 89% to $1,695,825 from $897,494 in 2006 mainly due to 2006 G&A costs include those costs during the period commencing on the date of acquisition of Argosy, to the year end.

Liquidated Damages

	Year Ended December 31, 2007	2006	Change from Prior Year
Liquidated Damages	$ 7,366,949	$ 1,527,988	382%

Liquidated damages expensed in 2007 relates to liquidated damages payable to our stockholders as a result of the registration statement for 50 million units sold in the second quarter of 2006 not becoming effective within the period specified in the share registration rights agreements for those securities. This registration statement became effective on May 14, 2007.

On June 27, 2007, under the terms of the Registration Rights Agreements, we obtained a sufficient number of consents from the signatories to the agreements waiving our obligation to pay in cash the accrued liquidated damages. We agreed to amend the terms of the warrants issued in the 2006 offering by reducing the exercise price of the warrants from $1.75 to $1.05 and extending the life of the warrants by one year.

The amendment to the terms of the warrants has been reflected as an increase of $8.6 million in the value of warrants recorded on the consolidated balance sheet.

Financial Derivative Loss

Financial Derivative Loss		**Year Ended December 31, 2007**
Realized financial derivative loss	$	391,345
Current portion of unrealized financial derivative Loss	$	1,593,629
Long-term portion of unrealized financial derivative loss	$	1,054,716
Total unrealized financial derivative loss	$	2,648,345
Financial derivative loss	$	3,039,690

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As required under the terms of the Credit Facility with Standard Bank Plc, in February of 2007, we entered into a derivative instrument for the purpose of obtaining protection against fluctuations in the price of oil in respect of at least 50% of the June 30, 2006 Independent Reserve Evaluation Report projected aggregate net share of Colombian production after royalties for the three-year term of the Facility. In accordance with the terms of the Facility, Gran Tierra Energy is required to maintain compliance with specified financial and operating covenants.

Foreign Exchange Loss

	Year Ended December 31, 2007	2006	Change from Prior Year
Foreign Exchange (Gain) Loss	$ (77,275)	$ 370,538	121%

The foreign exchange gain for the year ended December 31, 2007 increased to $77,275 from a loss of $370,538 for 2006. The foreign exchange gain resulted from the increase in 2007 of the value of the Colombian peso as compared to the US dollar.

Income Tax

	Year Ended December 31, 2007	2006	Change from Prior Year
Income Tax	$ 294,767	$ 677,380	-56%

The income tax expense for the year ended December 31, 2007 decreased 56% to $294,767 from $677,380 for 2006. The Colombia operations generated a net income before tax of $11,484,448 in 2007, which resulted in a local income tax liability, offset by a 2007 income tax recovery arising from losses of $2,740,990 incurred in Argentina. In Colombia, we have used available prior period loss carryforwards and Colombian income tax investment incentives, which permit additional tax deductions associated with capital investment in producing oil and natural gas properties, to decrease our current income tax otherwise payable.

Net Income (Loss) Available to Common Shares

	Year Ended December 31, 2007				2006				Cha
	Argentina	**Colombia**	**Corporate**	**Total**	**Argentina**	**Colombia**	**Corporate**	**Total**	**Argentina**
Net Loss									
Net loss (income) before income tax	$ 2,474,990	$ (11,484,448)	$ 17,181,895	$ 8,172,437	$ 411,028	$ (1,486,075)	$ 6,221,371	$ 5,146,324	502%
Income tax			-	294,767				677,380	
Net Loss				$ 8,467,204				$ 5,823,704	
Loss per share - Basic and Diluted									
				95,096,311				72,443,501	

Weighted Average Outstanding Common Shares - Basic and Diluted		
Loss per share - Basic and Diluted	$ 0.09	$ 0.08

The net loss for the year ended December 31, 2007 increased 45% to $8,467,204 or $0.09 per share from a loss of $5,823,704, or $0.08 per share in 2006. This loss includes a full year of operating activities for Colombia versus just over six months in 2006. The primary reason for the increase is due to the liquidated damages, as explained above, corporate stewardship costs including Sarbanes Oxley compliance, securities registration related costs and increased stock compensation due to increased option grants. Argentina’s 2007 operating segment loss increased 502% to $2,474,990 from a loss of $411,028 in 2006 primarily due to the increase in budgeted workover costs required to maintain production levels. Colombia increased its 2007 operating segment income by 673% to $11,484,448 from $1,486,075 in 2006 is a result to the increased production realized from the new discovery wells and the increase in price received for all production in 2007 versus 2006.

Results of Operations for the years ended December 31, 2006 as compared to period ended December 31, 2005

Revenue and Other Income
A summary of selected production, revenue and price information for the year ended December 31, 2006 and the period ended December 31, 2005 is presented in the following table:

	Year Ended December 31, 2006			Periods Ended December 31, 2005			Change from Prior Period		
	Argentina	Colombia	Total	Argentina	Colombia	Total	Argentina	Colombia	Total
Production, net of royalties (2)									
Oil and NGLs (Bbls)	127,712	129,209	256,921	25,132	-	25,132	408%	100%	922%
Gas (Mcf)	41,447	-	41,447	180,320	-	180,320	-77%	-	-77%
Oil, Gas and NGLs (Boe) (1)	129,784	129,209	258,993	34,148	-	34,148	280%	100%	658%
Revenue and other income									
Oil and NGLs (Bbls)	$ 5,033,363	$ 6,612,190	$ 11,645,553	$ 946,098	-	$ 946,098	432%	100%	1,131%
Gas	75,488	-	75,488	113,199	-	$ 113,199	-33%	-	-33%
	$ 5,108,851	$ 6,612,190	$ 11,721,041	$ 1,059,297	-	$ 1,059,297	382%	100%	1,006%
Other - Corporate			$ 351,872			-			100%
			$ 12,072,913			$ 1,059,297			1,040%
Average Prices									
Oil and NGLs (Per Bbl)	$ 39.41	$ 51.17	$ 45.33	$ 37.65	-	$ 37.65	5%	100%	20%
Gas (Per Mcf)	$ 1.82	-	$ 1.82	$ 0.63	-	$ 0.63	189%	-	189%

(1) Gas volumes are converted to barrels ("bbl's") of oil equivalent ("Boe") at the rate of 20 thousand cubic feet ("Mcf") of gas per barrel of oil based upon the approximate relative values of natural gas and oil. Natural Gas Liquids (NGLs") volumes are converted to Boe's on a one-to-one basis with oil.

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

Crude oil and NGL production for the year ended December 31, 2006 increased 922 % to 256,921 barrels from 25,132 barrels for the year ended December 31, 2005. The average price received per barrel of oil increased 20% to $45.33 per barrel for 2006 from $37.65 per barrel in 2005. As a result, revenue and other income for the year ended December 31, 2006 increased 1,040% to $12,072,913 compared to $1,059,297 for the year ended December 31, 2005. The 2006 production included Colombian production subsequent to the acquisition of Argosy in June 20, 2006. Also, in Argentina, the 2006 results include a full year of activities at Palmar Largo, four months at Nacatimbay, six months of activities at El Vinalar beginning July 1, 2006, and one month of activities at Chivil, commencing December 1, 2006. Revenues in 2005 reflect only the Argentina operations for a four month period from September 1, 2005, the date of acquisition of the Palmar Largo and Nacatimbay properties. Natural gas production in 2006 decreased 77% to 41,447 Mcf from 180,320 Mcf in 2006 with the average price increasing 189% to $1.82 per Mcf from $0.63 per Mcf. The volume decrease was a result of an operations decision to use the gas production for operating power generation and market only the unused excess.

In Argentina, crude oil and NGL production after 12% royalties for the year ended December 31, 2006 increased 408% to 127,712 barrels compared to 25,132 barrels for 2005. This increased production includes 118,121 barrels from Palmar Largo, 7,644 barrels from El Vinalar for the period July 1 to December 31, 2006, and 1,947 barrels from Chivil for December 1 to December 31, 2006. Average daily production for these periods in 2006 was 324 barrels from Palmar Largo, 42 barrels from El Vinalar (21 barrels per day for the year) and 63 barrels (5 barrels per day for the year) from Chivil. Oil sales at Palmar Largo during 2005 were 25,132 barrels, or an average of 206 barrels per day for the period (69 barrels per day for the year), due to severe weather conditions in Northern Argentina, as extreme rainfall and poor road conditions curtailed tanker truck traffic through November and December 2005. Natural gas sales, after royalties of 12%, at Nacatimbay in 2006 were 41,447 Mcf as compared to 180,320 Mcf in 2005.

In Argentina, net revenue for the year ended December 31, 2006, after deducting royalties at an average royalty rate of 12% of production revenue, and after deducting turnover taxes, increased 432% to $5,033,363 ($39.41 per barrel) for oil and NGLs and decreased 33% to $75,488 ($1.82 per Mcf) for natural gas as compared to $946,098 ($37.65 per barrel) and $113,199 ($0.63 per Mcf), respectively, for 2005. Increased production from most properties due to a full year's production in 2006 as compared to a partial year's production in 2005 and increased prices received due to increased world oil prices in 2006 as compared to 2005 have resulted in the increase in net revenue. Oil and natural gas prices are effectively regulated in Argentina.

In Colombia, crude oil and NGL production, after royalties ranging from 10% to 22% (including a 2 percent overriding royalty), for the year ended December 31, 2006 increased 100% to 129,209 barrels as compared to nil production for 2005. Colombia's production and results of operations began June 21, 2006 in conjunction with our acquisition of Argosy. Production after royalties was comprised of 65,176 barrels from the Santana block and 64,033 barrels from the Guayuyaco block, representing a combined average production rate of 692 barrels per day for the period (354 barrels per day for the year).

In Colombia, crude oil and NGL revenue, net of royalties, for the year ended December 31, 2006 increased 100% to $6,612,190 and $51.17 per barrel as compared to no revenue for 2006.

Interest income earned on our cash deposits was $351,872 for the year ended December 31, 2006 and none in 2005.

Operating Expenses

	Year Ended December 31, 2006			Period Ended December 31, 2005			Change from Prior Year		
	Argentina	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**
Operating Expense									
Operating Expense	$ 2,846,705	$ 1,386,765	$ 4,233,470	$ 395,287	$ -	$ 395,287	620%	100%	971%
Operating Expense per Boe	$ 21.93	$ 10.73	$ 16.35	$ 11.58		$ 11.58	89%	100%	41%

For the year ended December 31, 2006, operating expenses increased 971% to $4,233,470 ($16.35 per Boe) compared to $395,287 ($11.58 per Boe) in 2005, reflecting the inclusion in Argentina of operations for a full year at Palmar Largo, four months at Nacatimbay, six months of activities at El Vinalar and one month at Chivil. Colombia's operations commenced June 21, 2006 as a result of the purchase of Argosy. Operating expenses totaled $395,287 for the period from incorporation on January 26, 2005 to December 31, 2005, representing four months of operations in Argentina.

In Argentina, operating expenses for 2006 increased 620% to $2,846,705 ($21.93 per Boe) as compared to $395,287 for 2005 ($11.58 per Boe). The current year operating costs are higher than in the same periods of 2006 due to workovers undertaken in the current year, and 2005 contains only four months of operations commencing from the initial purchase of Argentine assets.

In Colombia, operating expenses were $1,386,765 ($10.73 per Boe) for the period June 21 to December 31, 2006. Colombia's 2006 operating costs included $4.11 per Boe of budgeted workover expense carried out in the Guayuyaco and Santana blocks.

Depletion, Depreciation and Accretion

	Year Ended December 31, 2006			Period Ended December 31, 2005			Change from Prior Period		
	Argentina	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**
DD&A									

DD&A	$ 1,550,544	$ 2,494,317	$ 4,044,861	$ 453,022	$ -	$ 453,022	242%	100%	793%
Other - Corporate			$ 43,576			$ 9,097			379%
			$ 4,088,437			$ 462,119			785%
DD&A per Boe	$ 11.95	$ 19.30	$ 15.79	$ 13.27	-	$ 13.53	-10%	100%	17%

Depreciation, depletion and accretion for the year ended December 31, 2006 increased 785% to $4,088,437 from $462,119 for 2005. The 2006 DD&A includes a full year of operations at Palmar Largo, additional Argentina acquisitions in 2006, and the inclusion of Colombia operations in June 2006. Depreciation, depletion and accretion recorded in 2005 primarily relates to the depletion of the acquisition cost for the Argentina properties.

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General and Administrative

	Year Ended December 31, 2006			Period Ended December 31, 2005			Change from Prior Period		
	Argentina	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**	**Argentina**	**Colombia**	**Total**
G&A									
G&A	$ 1,122,980	$ 897,494	$ 2,020,474	$ 331,033	$ -	$ 331,033	239%	100%	510%
Other - Corporate			$ 4,978,330			$ 2,151,037			131%
			$ 6,998,804			$ 2,482,070			182%
G&A per Boe	$ 8.65	$ 6.95	$ 27.02	$ 9.69		$ 72.69	-11%	100%	-63%

General and administrative costs for the year ended December 31, 2006 increased 182% to $6,998,804 from $2,482,070 for 2006. The incremental increase in general and administrative costs in 2006 was primarily due to operating fully-staffed branch offices in Colombia and Argentina, the increased level of activity related to our expansion of operations, which resulted from acquisition of the Argosy assets in Colombia and properties in Argentina, and costs related to the registration of our securities.

Liquidated Damages

	Year Ended December 31, 2006	Period Ended December 31, 2005	Change from Prior Period
Liquidated Damages	$ 1,527,988	$ -	100%

Liquidated damages of $1,527,988 recorded in 2006 relate to liquidated damages payable to our stockholders as a result of the registration statements for our securities issued in 2005 and 2006 not becoming effective within the periods specified in the share registration rights agreements for those securities. The amount expensed includes $269,923 related to 15,047,606 units issued in the fourth quarter of 2005 and first quarter of 2006 and $1,258,065 related to 50 million units sold in the second quarter of 2006. We did not have any liquidated damages in 2005.

Foreign Exchange Loss

	Year Ended December 31, 2006	Period Ended December 31, 2005	Change from Prior Period
Foreign Exchange (Gain) Loss	$ 370,538	$ (31,271)	1,285%

The foreign exchange loss for the year ended December 31, 2006 increased to $370,538 from a gain of $31,271 for 2005. The loss arose primarily from translation of local currency denominated transactions in our South American operations into US dollars.

Income Tax

	Year Ended December 31, 2006	Period Ended December 31, 2005	Change from Prior Period
Income Tax Expense (Recovery)	$ 677,380	$ (29,228)	2,418%

The income tax expense for the year ended December 31, 2006 increased 2,418% to $677,380 from a recovery of $29,228 for 2005. The Colombia operations generated a net income before tax of $2.4 million dollars, which resulted in a local income tax liability, offset by income tax assets arising from losses incurred in Argentina.

Net Income (Loss) Available to Common Shares

	Year Ended December 31, 2006				Period Ended December 31, 2005				Change from Prior		
	Argentina	**Colombia**	**Corporate**	**Total**	**Argentina**	**Colombia**	**Corporate**	**Total**	**Argentina**	**Colombia**	**Corporate**
Net Loss											
Net loss (income) before income tax	$ 411,028	$ (1,486,075)	$ 6,221,371	$ 5,146,324	$ 112,445	$ -	$ 2,136,463	$ 2,248,908	266%	100%	191%
Income tax				677,380				(29,228)			
Net Loss				$ 5,823,704				$ 2,219,680			
Loss per share - Basic and Diluted											
Weighted Average Outstanding Common Shares - Basic and Diluted				72,443,501				13,538,149			
Loss per share - Basic and Diluted				$ 0.08				$ 0.16			

The net loss for the year ended December 31, 2006 increased 162% to $5,823,704 or $0.08 per share from a loss of $2,219,680, or $0.16 per share in 2005. This loss includes a full year of operating activities at Palmar Largo and six months plus ten days of operations in Colombia, and costs related to the share registration statements. The net loss for the period from incorporation on January 26, 2005 to December 31, 2005 reflect four months of operating activity in Argentina, twelve months of business activity and significant costs relating to the November 10, 2005 share exchange transactions.

Liquidity and Capital Resources

During 2007, we relied upon cash provided by operations and the proceeds of 2006 private placements to fund ongoing operations and our capital investment program. As of December 31, 2007, our cash and cash equivalents balance was $18,188,817 million and our current assets (including cash and cash equivalents balance) less current liabilities were $8,058,049, compared to cash and cash equivalents of $24,100,780 and current assets (including cash and cash equivalents balance) less current liabilities of $14,541,498 million at December 31, 2006. We also have a credit facility with a bank that provides for borrowing in an amount based on the present value of our petroleum reserves, up to a maximum of $50 million, described below.

Effective February 28, 2007, we entered into a credit facility with Standard Bank Plc. The facility has a three-year term which may be extended by agreement between the parties. The borrowing base is the present value of our petroleum reserves up to maximum of $50 million. The initial borrowing base is $7 million and the borrowing base will be re-determined semi-annually based on reserve evaluation reports. As a result of Standard Bank Plc's review of our Mid-Year 2007 Independent Reserve Audit, we have received preliminary approval to increase our borrowing base to $20 million. The facility includes a letter of credit sub-limit of up to $5 million. Amounts drawn down under the facility bear interest at the Eurodollar rate plus 4%. A stand-by fee of 1% per annum is charged on the un-drawn amount of the borrowing base. The facility is secured primarily by our Colombian assets. Under the terms of the facility, we are required to maintain compliance with specified financial and operating covenants. We were required to enter into a derivative instrument for the purpose of obtaining protection against fluctuations in the price of oil in respect of at least 50% of the June 30, 2006 Independent Reserve Evaluation Report projected aggregate net share of Colombian production after royalties for the three-year term of the Facility. As of December 31, 2007, no amounts have been drawn-down under the facility. In accordance with the terms of the credit facility with Standard Bank Plc, we entered into a costless collar hedging contract for crude oil based on West Texas Intermediate ("WTI") price, with a floor of $48.00 and a ceiling of $80.00, for a three-year period, for 400 barrels per day from March 2007 to December 2007, 300 barrels per day from January 2008 to December 2008, and 200 barrels per day from January 2009 to February 2010. For the year ended December 31, 2007, we recorded a loss of $3,039,690 on derivative financial instruments.

During the year ended December 31, 2007, we reduced our cash balances by $5,911,963 as compared to an increase in 2006 of $21,879,324. Net cash provided by operating activities for the year ended December 31, 2007 increased to $8,761,439 as compared to $2,010,056 for 2006. The increase was mainly due to the significant increase in oil production and the associated sales price received offset by costs associated with budgeted workovers in both Colombia and Argentina, G&A expenditures associated with increased stewardship costs, including Sarbanes Oxley related expenditures, and securities registration issues, as further explained above in our review of the results of operations. Net cash used in investing activities for the year ended December 31, 2007 decreased 68% to $15,392,705 from $48,206,588 in 2006. During 2007, we expended $15,796,332 (net of changes in non-cash working capital related to capital expenditures of $232,822) in oil and gas property expenditures relating to our drilling and other oilfield activities primarily in Colombia as compared to $10,274,139 (net of changes in non-cash working capital expenditures of $8,026,375) for 2006. In 2006, we expended $36,911,959 related to the purchase of Argosy. Net cash provided by financing activities for the year ended December 31, 2007 was $719,303 as a result of the issuance of common shares upon exercise of warrants. In 2006, net cash provided by financing activities was $68,075,856 mainly as a result of the issuance of common shares through private placements.

During the year ended December 31, 2006, we increased our cash balances by $21,879,324 and funded our capital expenditures and operating expenditures from proceeds of a series of private placements of our securities. Cash inflows comprised $2,010,056 from operating activities and $68,075,856 from financing activities, offset by cash outflows of $48,206,588 for investing activities. Proceeds from private placements included $75,000,000, less issue costs of $6,303,699, from the sale of 50,000,000 units of our securities in June 2006, $610,000 from the sale of 762,500 units in the first quarter of 2006, and proceeds from the exercise of warrants to purchase common stock. However, of the amount raised, $1,280,951 was held in escrow at December 31, 2006, and the holders of those units had the right to return the units to us and receive their purchase price back under the terms of the escrow agreement because we were unable to obtain a securities laws exemption for those holders by a specified date. At December 31, 2006, we were in discussions with those stockholders regarding whether or not they would exercise that right.

During 2005, we funded the majority of our capital expenditures from funds received through three private placements of our securities. Cash inflows from financing activities were $13,206,116, offset by cash outflows of $2,277,065 from operating activities and $8,707,595 for investing activities. Proceeds from private placements included $11,428,084 from the sale of 14,285,106 units of our securities in the fourth quarter of 2005.

Capital expenditures for the year ended December 31, 2006 were $47,186,098 (net of changes in non-cash working capital related to capital expenditures of $8,026,375) and were primarily related to the Argosy purchase in Colombia, the purchase of the El Vinalar and CGC properties in Argentina, development activity at Palmar Largo, drilling activities in Colombia, and office equipment and leasehold improvements in both Calgary and Argentina. During 2005, capital expenditures for the period from incorporation on January 26, 2005 to December 31, 2005, were $8,707,595, predominantly for the acquisition cost of the Palmar Largo, Nacatimbay and Ipaguazu interests in Argentina.

During the year ended December 31, 2007, we spent $15,976,332 (net of changes in non-cash working capital related to capital expenditures of $232,822) on capital projects. During 2007, we drilled seven wells, conducted several workovers of existing wells, and conducted technical studies on our existing acreage.

In Argentina, capital expenditures for the year ended December 31, 2007, were $1,679,305, including $222,932 of accrued expenditures at December 31, 2007. We incurred costs of $659,704 to complete the Puesto Climaco-2 sidetrack well in the Vinalar Block which was drilled in December 2006. Capital expenditures also include the acquisition and reprocessing of seismic in several areas, facility upgrades in Parma Largo and non-cash capitalized stock-based compensation expense.

In Colombia, capital expenditures for the year ended December 31, 2007, were $14,214,835, including $7,984,841 of accrued expenditures at December 31, 2007. In Colombia, we drilled six new wells in 2007. We drilled the Laura-1 exploration well in the Talora Block in January 2007, the Caneyes-1 exploration well in the Rio Magdalena Block in February 2007, and the Soyona-1 and Cachapa-1 exploration wells in the Primavera Block in April and March 2007, respectively. These wells were plugged and abandoned. We drilled the Caneyes-1 well at a net cost to us of $1,669,888 and the drilling costs for the three other wells were paid by our partners.

We drilled successful wells in the Chaza and Guayayaco areas. We drilled the Juanambu-1 well in March 2007 and encountered hydrocarbon shows in four zones. Testing established the presence of a significant oil accumulation. We drilled and tested the Costayaco-1 well, which also indicated a significant accumulation of oil in a number of zones. Consequently, our proven reserves in Colombia have substantially increased. We put these wells on production in the third quarter of 2007. We drilled the Juanambu-1 and Costayaco-1 wells and commenced drilling of Costayaco-2 for a net cost of $7,598,626. We incurred costs of $4,946,321 on other projects in Colombia during 2007 including $1,673,349 for completion of a 3-D seismic program in Costayaco and $1,162,923 related to a 2-D seismic program in the Rio Magdalena block.

We expect to incur additional development costs as facilities are upgraded in both locations to facilitate production. In addition, we initiated drilling of Costayaco-2 in December 2007 and completed drilling and cased the well in January 2008. We commenced drilling Costayaco-3 in January 2008. We are planning further field development in these areas as a result of the Costayaco and Juanambu discoveries. We completed a new 3-D seismic data acquisition program over the Costayaco structure to optimize positioning of future drilling locations.

In Peru, operations in 2007 included technical studies of Block 122 and Block 128 and the initiation of an aero magnetic and gravity survey over both blocks. This program commenced in the fourth quarter of 2007 and we expect it to be completed in 2008. Expenditures in 2007 were $656,244, with estimated expenditures to complete the work in 2008 of $1.5 million.

Plans for 2008 include the drilling of two exploration wells (at no cost to Gran Tierra Energy) and six development wells (approximately 48% of the cost to be paid by Gran Tierra Energy) in Colombia and one exploration well (50% of the cost to be paid by Gran Tierra Energy) in Argentina along with related facility and pipeline infrastructure for a total capital expenditure budget of $56.8 million. We contemplate several well workovers for wells on existing producing and shut-in fields. In addition to current budgeted projects, we may pursue new ventures in South America, in areas of current activity and in new regions or countries. There is no assurance additional opportunities will be available, or if we participate in additional opportunities that those opportunities will be successful. Based on projected production, prices and costs, we believe that our current operations and capital expenditure program can be maintained from cash flow from existing operations, cash on hand, and our credit facility, barring unforeseen events or a severe downturn in oil and gas prices. Should our operating cash flow decline, we would examine measures such as reducing our capital expenditure program, issuance of debt, or issuance of equity.

Future growth and acquisitions will depend on our ability to raise additional funds through equity, warrant exercises and/or debt markets. During 2005 and 2006 we completed financing initiatives to support acquisition initiatives, which have also brought additional production and cash flow into our company. Increases in the borrowing base under our credit facility are dependent on our success in increasing oil and gas reserves and on future oil prices. Additional funds will be provided to us as holders of our warrants to purchase common shares decide to exercise the warrants.

Our initiatives to raise debt or equity financing to fund capital expenditures or other acquisition and development opportunities 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 stockholders, and this dilution would be exacerbated by a decline in 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 that are not currently pledged under our existing credit facility.

Off-Balance Sheet Arrangements

As at December 31, 2007 and 2006, we had no off-balance sheet arrangements.

Contractual Obligations

Gran Tierra Energy holds three categories of operating leases: office, vehicle and housing. We pay monthly costs of $57,638 for office leases, $4,791 for vehicle leases, $9,400 for a compressor and $2,561 for certain employee accommodation leases in Colombia.

We entered into four capital leases in 2006 for office equipment in Calgary, Canada. The leases expire between 2008 and 2011. As of December 31, 2007 capital assets were valued at $21,841 (net of amortization of $17,870). Total rent expense for 2007 was $291,975 (2006 - $221,477; 2005 - $26,904).

Capital lease agreements contain interest rates between 4.75 and 20.5 percent and mature over one to four years. Interest expense incurred under these capital leases to December 31, 2007 was $2,657 (2006 - $2,346).

We have contracted with a third party to provide catering services for our field operations in Colombia. The contract ends January 14, 2009. The remaining contractual commitment is $280,771 to be incurred evenly over the remaining duration of the contract.

We have contracted with a third party to provide a helicopter for field transportation for our Colombia field operations. The contract ends September 30, 2008. The minimum obligation under the contract is for 30 flight hours per month at a rate of $880 per hour. The remaining nine month obligation is $237,600.

Future lease payments and other contractual obligations at December 31, 2007 are as follows:

	Payments Due in Period				
	Total	Less than 1 year	1-3 Years	3-5 years	more than 5 years
Catering contract obligation	$ 280,771	$ 269,540	$ 11,231	$ -	$ -
Helicopter contract obligation	237,600	237,600	-	-	-
Operating lease obligations	2,581,233	833,799	1,460,629	286,805	-
Capital lease obligations	20,056	9,991	10,065	-	-
Total	$ 3,119,660	$ 1,350,930	$ 1,481,925	$ 286,805	$ -

Critical Accounting Estimates

Use of Estimates

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP"). The preparation of financial statements in accordance with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements, and revenues and expenses during the reporting period.

The critical accounting policies used by management in the preparation of our consolidated financial statements are those that are important both to the presentation of our financial condition and results of operations and require significant judgments by management with regards to estimates used. Our critical accounting policies and significant judgments and estimates related to those policies are discussed below. We have reviewed these critical accounting policies with the Audit Committee of the Board of Directors.

Oil and Gas Accounting-Reserves Determination

We follow the full cost method of accounting for our investment in oil and natural gas properties, as defined by the SEC, as described in note 2 to our consolidated financial statements. Full cost accounting depends on the estimated reserves we believe are recoverable from our oil and gas reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geo-physical, engineering and economic data.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the US as prescribed by the Society of Petroleum Engineers. Reserve estimates are audited at least annually by independent qualified reserves consultants, Gaffney, Cline & Associates Inc.

Our board of directors oversees the annual review of our oil and gas reserves and related disclosures. The Board meets with management periodically to review the reserves process, results and related disclosures and appoints and meets with the independent reserves consultants to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

Reserves estimates are critical to many of our accounting estimates, including:

· Determining whether or not an exploratory well has found economically producible reserves.

- Calculating our unit-of-production depletion rates. Proved reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense.

- Assessing, when necessary, our oil and gas assets for impairment. Estimated future cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Oil and Gas Accounting and Impairment

The accounting for and disclosure of oil and gas producing activities requires that we choose between GAAP alternatives. We use the full cost method of accounting for our oil and natural gas operations. Under this method, separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration and development activities) are capitalized. The sum of net capitalized costs and estimated future development costs of oil and natural gas properties for each full cost center are depleted using the units-of-production method. Changes in estimates of proved reserves, future development costs or asset retirement obligations are accounted for prospectively in our depletion calculation.

Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties the costs of which are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, these properties are grouped for purposes of assessing impairment. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter on a country-by-country basis. The ceiling limits these pooled costs to the aggregate of the after-tax, present value, discounted at 10%, of future cash flows attributable to proved reserves, known as the standardized measure, plus the lower of cost or market value of unproved properties less any associated tax effects. Cash flow estimates for our impairment assessments require assumptions about two primary elements — constant prices and reserves. It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserves estimate and the estimated discounted cash flows is complex because of the necessary assumptions that need to be made regarding period end production rates, period end prices and costs. If these capitalized costs exceed the ceiling, we will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expense in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling. Due to the complexity of the calculation, we are unable to provide a reasonable sensitivity analysis of the impact that a reserves estimate decrease would have on our assessment of impairment. A reduction in oil and natural gas prices and/or estimated quantities of oil and natural gas reserves would reduce the ceiling limitation and could result in a ceiling test write-down.

We assessed our oil and gas properties for impairment as at December 31, 2007, 2006 and 2005 and found no impairment write-downs were required based on our assumptions. Estimates of standardized measure of our future cash flows from proved reserves were based on realized crude oil prices of $90.01 in Colombia and $42.00 for our Argentina properties as at December 31, 2007. A future reduction in oil prices and/or quantities of proved reserves would reduce the ceiling limitation and may result in a ceiling test write-down.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future asset retirement obligations requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record asset retirement obligations in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities and chemical plants. In arriving at amounts recorded, we make numerous assumptions and judgments with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations we have recorded result in an increase to the carrying cost of our property, plant and equipment. The obligations are accreted with the passage of time. A change in any one of our assumptions could impact our asset retirement obligations, our property, plant and equipment and our net income.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results. We are confident, however, that our assumptions are reasonable.

Goodwill

Goodwill represents the excess of purchase price of business combinations over the fair value of net assets acquired and we test for impairment at least annually. The impairment test requires allocating goodwill and all other assets and liabilities to reporting units. We estimate the fair value of each reporting unit and compare it to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, we write down the goodwill to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for our reporting units, we estimate the fair values of the reporting units based upon estimated future cash flows of the reporting unit. The goodwill on our financial statements was a result of the Argosy acquisition, and relates entirely to the Colombia reporting segment.

Deferred Income Taxes

We follow the liability method of accounting for income taxes whereby we recognize future income tax assets and liabilities based on temporary differences in reported amounts for financial statement and tax purposes. We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have made adequate provision for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. As of December 31, 2007, we had no deferred tax assets for which management considers realization is more likely than not.

Share-Based Payment Arrangements

We record share-based payment arrangements in accordance with SFAS 123 (revised 2004), “Share-Based Payment” (“SFAS 123R”) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including employee stock options based on estimated fair values.

SFAS 123R requires companies to estimate the fair value of share-based payment awards on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in our Consolidated Statement of Operations.

Under SFAS 123R, share-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Compensation expense is recognized using the accelerated method. As share-based compensation expense recognized in the Consolidated Statements of Operations is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. SFAS 123R requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

Under SFAS 123 R, we utilized a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. Our determination of fair value of share-based payment awards on the date of grant using an option-pricing model is affected by our stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, our expected stock price volatility over the term of the awards, and actual and projected employee stock option exercise behaviors.

Option-pricing models were developed for use in estimating the value of traded options that have no vesting or hedging restrictions and are fully transferable. Because (1) our employee stock options have certain characteristics that are significantly different from traded options, and (2) changes in the subjective assumptions can materially affect the estimated value, in management's opinion, the existing valuation models may not provide an accurate measure of the fair value of our employee stock options. Although the fair value of employee stock options is determined in accordance with SFAS No. 123R using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction. We are responsible for determining the assumptions used in estimating the fair value of its share-based payment awards.

Warrants

We follow the fair-value method of accounting for warrants issued to purchase our common stock. The change of $8.6 million in the fair value of warrants issued in the 2006 Offering, arising from the amendment to the terms of the warrants in connection with the settlement of the liability for liquidated damages, was determined using a Black-Scholes warrant pricing model based on a 25% volatility rate, which reflects a typical volatility rate used to value this type of financial instrument.

New Accounting Pronouncements

In July 2006, the FASB issued FIN 48 (FASB Interpretation Number) *Accounting for Uncertainty in Income Taxes* with respect to FAS 109 *Accounting for Income Taxes* regarding accounting for and disclosure of uncertain tax positions. This guidance seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation requires that we recognize the impact of a tax position in the financial statements if that position is more likely than not of being sustained on audit, based on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. In accordance with the provisions of FIN 48, any cumulative effect resulting from the change in accounting principle is to be recorded as an adjustment to the opening balance of accumulated deficit. This interpretation is effective for fiscal years beginning after December 15, 2006 and its adoption on January 1, 2007 did not have a material impact on our consolidated financial statements and did not require us to record any amounts in the financial statements.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements.* SFAS 157 defines fair value, establishes a framework for measuring fair value under US generally accepted accounting principles and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. The provisions of SFAS 157 are to be applied prospectively, except for the initial impact in certain situations, which are required to be recorded as an adjustment to the opening balance of retained earnings in the year of adoption. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In December 2006, the FASB issued Staff Position (FSP) EITF 00-19-2, *Accounting for Registration Payment Arrangements.* FSP EITF 00-19-2 specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be separately recognized and measured in accordance with SFAS No. 5, *Accounting for Contingencies*. This FSP is effective for fiscal years beginning after December 15, 2006. We early adopted this FSP during the year ended December 31, 2006 and recorded $1,258,065 in liquidated damages as an expense in the consolidated statement of operations and deficit and the same amount in accrued liabilities at December 31, 2006. For the year ended December 31, 2007, we expensed an additional amount of $7,366,949. As at December 31, 2007, we had an accumulated expense for liquidated damages of $8,625,014. Pursuant to an amendment of terms of Registration Rights Payments with respect to the associated shareholder agreement, our shareholders waived the right to settle the liquidated damages in cash and in lieu agreed to an amendment of the exercise price of the warrants from $1.75 to $1.05 on June 27, 2007, and an extension of one year in the term for the warrants. The settlement of the liquidated damages is reflected as an increase to the value of the warrants included in the shareholders' equity section of the consolidated balance sheet.

In February 2007, the FASB issued SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities". SFAS 159 permits an entity to elect fair value as the initial and subsequent measurement attribute for many financial assets and liabilities. Entities electing the fair value option would be required to recognize changes in fair value in earnings. Entities electing the fair value option are required to distinguish on the face of the statement of financial position, the fair value of assets and liabilities for which the fair value option has been elected and similar assets and liabilities measured using another measurement attribute. SFAS 159 is effective for our fiscal year 2008. The adjustment to reflect the difference between the fair value and the carrying amount would be accounted for as a cumulative-effect adjustment to retained earnings as of the date of initial adoption. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In December 2007, the FASB issued SFAS 141 (R), "*Business Combinations*", and SFAS 160, "*Noncontrolling Interests in Consolidated Financial Statements*". SFAS 141 (R) requires an acquirer to measure the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their fair values on the acquisition date, with goodwill being the excess value over the net identifiable assets acquired. SFAS 160 clarifies that a noncontrolling interest in a subsidiary should be reported as equity in the consolidated financial statements. The calculation of earnings per share will continue to be based on income amounts attributable to the parent. SFAS 141 (R) and SFAS 160 are effective for financial statements issued for fiscal years beginning after December 15, 2008. Early adoption is prohibited and the provisions are applied prospectively. We have not yet determined the effect on our consolidated financial statements, if any, upon adoption of SFAS 141 (R) or SFAS No. 160.

Item 7A. ***Quantitative and Qualitative Disclosure about Market Risk***

Our principal market risk relates to oil prices. We have not hedged these risks in the past. Essentially 100% of our revenues are from oil sales at prices which are defined by contract relative to West Texas Intermediate and adjusted for transportation and quality, for 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.

In accordance with the terms of the credit facility with Standard Bank Plc, which we entered into on February 28, 2007, we entered into a costless collar hedging contract for crude oil based on West Texas Intermediate ("WTI") price, with a floor of $48.00 and a ceiling of $80.00, for a three-year period, for 400 barrels per day from March 2007 to December 2007, 300 barrels per day from January 2008 to December 2008, and 200 barrels per day from January 2009 to February 2010. At December 31, 2007, the value of this costless collar was a loss of $2,648,346. A hypothetical 10% increase in WTI price on December 31, 2007 would cause the loss to increase by approximately $1,475,168, and a hypothetical 10% decrease in WTI price on December 31, 2007 would cause the loss to decrease by approximately $1,258,675.

We consider our exposure to interest rate risk to be immaterial. Interest rate exposures relate entirely to our investment portfolio, as we do not have short-term or long-term debt. However, if we draw down amounts under our credit facility with Standard Bank Plc, we will incur interest rate risk with respect to the amounts drawn down and outstanding. 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 issuers at overnight rates. We do not hold any of these investments for trading purposes. We do not hold equity investments.

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. price of West Texas intermediate oil. In Colombia, we receive 75% of oil revenues in U.S. dollars and 25% in Colombian pesos at current exchange rates. The majority of our capital expenditures in Colombia are in U.S. dollars and the majority of local office costs are in local currency. As a result, the 75%/25% allocation between U.S. dollar and peso denominated revenues is approximately balanced between U.S. and peso expenditures, providing a natural currency hedge. In Argentina, reference prices for oil are in U.S. dollars and revenues are received in Argentine pesos according to current exchange rates. The majority of capital expenditures within Argentina have been in U.S. dollars with local office costs generally in pesos. While we operate in South America exclusively, the majority of our spending since our inauguration has been for acquisitions. The majority of these acquisition expenditures have been valued and paid in U.S. dollars.

Item 8. ***Financial Statements and Supplementary Data.***

Report of Independent Registered Chartered Accountants

To the Board of Directors and Shareholders of Gran Tierra Energy Inc.

We have audited the accompanying consolidated balance sheets of Gran Tierra Energy Inc. and subsidiaries (the “Company”) as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years then ended, and for the period from incorporation on January 26, 2005 to December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the two years then ended and for the period from incorporation on January 26, 2005 to December 31, 2005 in accordance with accounting principles generally accepted in the United States of America.

As discussed in Note 13, the accompanying 2007 and 2006 consolidated financial statements have been restated. We therefore withdraw our previous report dated March 7, 2008 on those financial statements, as originally filed.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 7, 2008 (May 12, 2008 as to the effects of the material weakness), expressed an adverse opinion on the Company’s internal control over financial reporting because of a material weakness.