GRAN TIERRA ENERGY INC.
Form 10-K
February 29, 2016

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

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

For the fiscal year ended December 31, 2015

or

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

For the transition period from __________ to __________

Commission file number 001-34018

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

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

200, 150 13 Avenue S.W.
Calgary, Alberta, Canada T2R 0V2
(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:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.001 per share	NYSE MKT
	Toronto Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None
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 ý
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 ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $0.8 billion.

On February 23, 2016, the following numbers of shares of the registrant's capital stock were outstanding: 287,129,518 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 3,638,889 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 4,903,177 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

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 2016 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2015.

Gran Tierra Energy Inc.

Annual Report on Form 10-K

Year Ended December 31, 2015

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Annual Report on Form 10-K regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words “believe”, “expect”, “anticipate”, “intend”, “estimate” “project”, “target”, “goal”, “plan”, “objective”, “should”, or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part I, Item 1A “Risk Factors” in this Annual Report on Form 10-K. The information included herein is given as of the filing date of this Form 10-K with the Securities and Exchange Commission (“SEC”) and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Annual Report on Form 10-K to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

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

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

Sales volumes represent production NAR adjusted for inventory changes and losses. Our oil and gas reserves are reported NAR. Our production is also reported NAR, except as otherwise specifically noted as "working interest production before royalties." NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Below are explanations of some commonly used terms in the oil and gas business and in this report.

Developed acres. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. Exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation activities. The process of the recovery of fluids from reservoirs and drilling and development of oil and gas reserves.

Exploration well. An exploration well is a well drilled to find a new field or new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells expressed as whole numbers and fractions of whole numbers.

Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. The SEC provides a complete definition of possible reserves in Rule 4-10(a)(17) of Regulation S-X.

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered. The SEC provides a complete definition of probable reserves in Rule 4-10(a)(18) of Regulation S-X.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. In general, reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each

month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. In general, reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

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

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production and requires the owner to pay a share of the costs of drilling and production operations.

PART I

Items 1 and 2. Business and Properties

General

Gran Tierra Energy Inc. together with its subsidiaries (“Gran Tierra”, "us", "our", or “we”) is an independent international energy company engaged in oil and gas acquisition, exploration, development and production. We are strategically focused on onshore oil and gas properties in Colombia and also own the rights to oil and gas properties in Brazil and Peru. Our Colombian properties represented 87% of our proved reserves NAR at December 31, 2015. The remainder of our proved reserves were attributable to our Brazilian properties.

Our company was incorporated under the laws of the State of Nevada on June 6, 2003, originally under the name Goldstrike Inc. We have acquired oil and gas producing and non-producing assets in Colombia, Peru, and Brazil, with our largest acquisitions being the acquisitions of Argosy Energy International L.P. in 2006, Solana Resources Limited in 2008 and Petrolifera Petroleum Limited in 2011.

All dollar ($) amounts referred to in this Annual Report on Form 10-K are United States (U.S.) dollars, unless otherwise indicated.

2015 Overview

During early 2015, largely as a result of the low commodity price environment and drilling results in Peru, we ceased all development expenditures in the Bretaña Field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. As a result, all probable and possible reserves associated with the field were reclassified as contingent resources.

On May 7, 2015, we entered into an agreement (the “Agreement”) with West Face SPV (Cayman) I L.P. (“West Face”) pursuant to which we settled a proxy contest. Pursuant to the terms of the Agreement, Gary Guidry was appointed as our President and Chief Executive Officer. Mr. Guidry replaced Duncan Nightingale in that role, who was serving as interim Chief Executive Officer since February 2015 and, with the appointment of Mr. Guidry as Chief Executive Officer, was designated as Executive Vice President. Additionally, effective May 11, 2015, Ryan Ellson was appointed as Chief Financial Officer. In connection with our entry into the Agreement, the size of our Board of Directors was expanded, new directors were appointed to fill the newly created vacancies and certain existing directors agreed not to stand for re-election at the 2015 annual meeting of stockholders. In June 2015, our Board of Directors approved a new capital program focusing on development activities in Colombia.

On January 13, 2016, we acquired all of the issued and outstanding shares of Petroamerica Oil Corp ("Petroamerica") for cash consideration of $70.6 million and the issuance of 13,656,719 shares of Gran Tierra common stock. The net purchase price of Petroamerica was $70.4 million, after giving consideration to estimated net working capital of $26.0 million. On January 25, 2016, we acquired all of the issued and outstanding shares of PetroGranada Colombia Limited ("PGC"). The net purchase price of PGC was $19.0 million, after giving consideration to estimated net working capital of $18.7 million. In addition, we agreed to pay an additional $4.0 million if cumulative production from the Putumayo-7 Block plus gross proved plus probable reserves under the Putumayo-7 Block meet or exceed 8 MMbbl in any year prior to January 2021. Combined proved NAR oil and gas reserves of Petroamerica and PGC as at December 31, 2015, were 3.9 MMBOE calculated in compliance with the SEC rules.

2015 Operational Highlights

In the year ended December 31, 2015, we incurred capital expenditures of $159.2 million, including $87.7 million in Colombia, $20.0 million in Brazil, $50.4 million in Peru and $1.1 million in Corporate. In the second half of 2015, after the change in management and substantial change of the board of directors, the majority of capital expenditures (86%) were incurred in Colombia.

The significant elements of our 2015 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Costayaco-25D and Costayaco-26D development wells in the Costayaco Field, and the Moqueta-17 and Moqueta-21D development wells in the Moqueta Field, as oil producers. The Moqueta-19i well was completed as a water injector as planned. We commenced drilling the Costayaco-24D and Costayaco-27i development well and started pre-drilling activities for the

Moqueta-20, 22 and 23 development wells. We also drilled the Moqueta-18i development well and encountered mechanical difficulties. This well is currently suspended.

- On the Garibay Block (50% WI, non-operated) and Tiple Block (owned by two other parties), the unitization of the Jilguero Field was completed and we became a 38.5% WI owner in the newly unitized field. Together with our partners, we drilled and completed three development wells, Jilguero Sur-2, Jilguero-3 and Jilguero-4 as oil producing wells.

- We completed the acquisition of 2-D seismic on the Cauca-7 (100% WI, operated), Sinu-1 (60% WI, operated) and Sinu-3 (51% WI, operated) Blocks and continued activities in preparation for the acquisition of 2-D seismic on the Putumayo-10 Block (100% WI, operated). We also commenced environmental impact assessments ("EIA"s) for future drilling on the Sinu-3 Block.

- We also continued facilities work at the Costayaco and Moqueta Fields on the Chaza Block, and on the Jilguero unitized Field within the Garibay Block.

In Brazil:

- On Blocks REC-T-86, Block REC-T-117 and Block REC-T-118 (100% WI, operated)), we completed the acquisition, processing and interpretation of 3-D seismic.

- On Block REC-T-155 (100% WI, operated), we initiated construction of an infield gas pipeline between the Tiê facilities and 3-GTE-03-BA.

In Peru:

- On Block 95 (100% WI, operated), we completed drilling operations on the Bretaña Sur 95-3-4-1X appraisal well on the L4 lobe in the Bretaña Field, which satisfied our work obligation for the fifth exploration period. We encountered approximately six feet of oil pay above the oil-water contact in the Vivian Sandstone Reservoir. This oil column was less than what we had estimated prior to drilling. As previously discussed, in February 2015, we ceased all further development expenditures in the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security.

- On Blocks 107 and 133 (100% WI, operated), we continued the environmental permitting process. On Block 107, we completed the acquisition, interpretation and processing of 2-D seismic and commenced planning activities for the Osheki-1 exploration well and the refurbishment of the base camp and well location. Both of these planning activities were suspended at the end of February 2015.

2016 Outlook

In January 2016, we announced our 2016 capital budget. Our base 2016 capital program of $107 million consists of: $76 million for Colombia; $8 million for Brazil; $6 million for Peru; and $17 million for other.

In Colombia, our base 2016 capital program includes two water injector wells in the Costayaco Field and three development wells in the Moqueta Field, both on the Chaza Block (100% WI, operated), two exploration wells and a development well in the Putumayo-7 Block (subject to regulatory approval, 100% WI, operated) and an exploration well on the Llanos-10 Block (50% WI, non-operated) with the costs being carried by a third party. Facilities work is also planned for the Chaza Block.

In Peru, the 2016 capital program includes only those activities required for retention of lands and security of assets. In Brazil, the capital program includes only minimal activity to implement water injection for reservoir pressure maintenance and to preserve current production levels. In both Peru and Brazil, operations have been scaled back significantly, with the aim of allowing time to explore and execute on options to maximize shareholder value.

In addition to our base 2016 capital budget, we have a discretionary capital budget of $61 million that we may utilize during 2016 in the event of an increase in commodity prices. If deployed, we expect that our discretionary capital budget would target six exploration wells, five development wells and seismic activities in Colombia.

We expect to finance our 2016 capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions.

Business Strategy

The Company's strategy is to efficiently grow and diversify its portfolio of exploration, development and production opportunities in Colombia. We are taking steps to maintain cash flows from existing assets, and seeking opportunities to leverage our financial strength to expand our Colombian operations and asset base.

Oil and Gas Properties

Colombia

On January 13, 2016, and January 25, 2016, respectively, we completed the acquisitions of all of the issued and outstanding shares of Petroamerica and PGC.

Excluding blocks subject to relinquishment, we have interests in 29 blocks in Colombia and are the operator on 16 of these blocks, including 14 blocks acquired through the acquisitions of Petroamerica and PGC (three operated). These blocks include interests in the Putumayo-7 Block for which assignment of WI is subject to approval, or final approval, by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH"). Relinquishments of our interests in four blocks in Colombia are subject to receipt of final documentation from the ANH. During 2015, unitization of the Jilguero Field on the Garibay and Tiple Block was completed and we became a 38.5% WI owner in the newly unitized field, we executed an Exploration and Production Contract for the Putumayo-4 Block farm-in, received final documentation from the ANH for relinquishment of our interest in the Magangué Block, and our contract on the Santana Block expired.

The following table provides a summary of selected data for our blocks in Colombia as at December 31, 2015, as well as a summary of selected combined data for Petroamerica and PGC as at December 31, 2015:

Block and Field(s)	Basin	WI	Estimated Proved Reserves, NAR	2015 Average Production NAR, BOEPD	Number of Productive Wells at December 31, 2015, Net	End of Production Phase	Acres, Net[1]
Chaza - Costayaco and Moqueta Fields	Putumayo	100% operated	29,375	16,601	28.0	2033 for Costayaco and 2037 for Moqueta	46,676
Guayuyaco - Guayuyaco and Juanambu Fields	Putumayo	70% operated	1,890	727	3.8	2030	36,656
Garibay (50% WI) - Jilguero Field (38.5% WI)	Llanos	50% non-operated	753	739	1.9	2037	19,460
Llanos-22 - Ramiriqui Field	Llanos	45% non-operated	1,672	810	0.9	2038	19,075
11 Other Blocks	Putumayo, Cauca, Catatumbo or Sinu	See below	—	95	—	—	2,652,763
Gran Tierra as at December 31, 2015[1]			33,690	18,972	34.6		2,774,630
Combined Petroamerica and PGC[2]			3,947	3,360	7.6		940,708
Pro forma Gran Tierra as at December 31, 2015[3]			37,637	22,332	42.2		3,715,338

(1) Excludes our interest in three blocks with a total of 0.8 million gross and net acres for which government approval of relinquishments was pending at December 31, 2015.

(2) We acquired Petroamerica and PGC subsequent to December 31, 2015. Estimated proved NAR reserves are based on independent reserves reports prepared by McDaniel with an effective date of December 31, 2015 for Petroamerica and PGC.

(3) Gives pro forma effect to the acquisitions of Petroamerica and PGC as if they had occurred on December 31, 2015.

Status of Exploration Phases

During 2015, the ANH introduced a number of programs which are intended to assist oil and gas companies operating in Colombia during the current low commodity price environment. One program provides an option for companies to apply for a nine month extension to fulfill different commitments and exercise rights during the exploration period (exploration, evaluation, among others). Another program provides an option for companies to apply requesting approval to transfer certain work obligations between blocks. We requested and were granted nine month extensions of the exploration phase on some of our blocks and are considering applying to request approval to transfer certain of our work obligations to other blocks.

Chaza Block (100% WI, operated)

The second additional exploration program ended on January 30, 2016. This exploration phase required one exploration well to be drilled, which was satisfied by the Eslabón Sur Deep-1 exploration well. The exploration period in the Chaza Block has ended and we retain the Moqueta and Costayaco Fields.

Guayuyaco Block (70% WI, operated)

We have completed all of our obligations in relation to this contract. Ecopetrol has the option to back-in to a 30% participation interest in any other new discoveries in the block.

Garibay Block (50% WI, non-operated)

We are in the second additional exploration program. We applied for and were granted an extension of this phase to July 24, 2016. We have an obligation to drill one exploration well in this exploration phase.

Llanos-22 Block (45% WI, non-operated)

We are in a unified first and second additional exploration program which will end on February 3, 2017, but our partner has requested a suspension of this exploration program. This exploration phase requires one exploration well to be drilled and the acquisition of 125 square kilometers of 3-D seismic.

Putumayo Piedemonte Norte Block (70% WI, operated)

We are in the first of six exploration phases, which is currently under suspension. This exploration phase requires the acquisition, processing and interpretation of 70 kilometers of 2-D seismic. We have already acquired 18 kilometers of 2-D seismic on this block.

Putumayo Piedemonte Sur Block (100% WI, operated)

We are in a unified phase two and three of six exploration phases. We applied for and were granted an extension of this phase for nine months to December 5, 2016. This unified phase requires the acquisition of 55 kilometers of 2-D seismic and one exploration well to be drilled. We have satisfied the 2-D seismic work obligation for this phase.

Cauca-6 Block (100% WI, operated)

We are in the exploration phase of this contract, which is currently under suspension. This phase requires the acquisition of 200 kilometers of 2-D seismic and the drilling of one stratigraphic well. We will have 815 days from the date the suspension is lifted to complete the work obligation.

Cauca-7 Block (100% WI, operated)

We are in the exploration phase of this contract. We applied for and were granted an extension of this phase to November 28, 2016. This phase requires the acquisition of 252 kilometers of 2-D seismic and the drilling of one stratigraphic well. We have satisfied the seismic work obligation.

Putumayo-10 Block (100% WI, operated)

We are in the first of two exploration phases. We requested and were granted a suspension of the exploration phase due to community and permitting issues. This phase requires the acquisition of 73 kilometers of 2-D seismic and two exploration wells to be drilled. We will have 20 months from the date the suspension is lifted to complete the work obligation.

Putumayo-1 Block (55% WI, operated)

We are in the first of two exploration phases. We requested and were granted a suspension of the exploration period due to community issues. This phase requires the acquisition of 159 square kilometers of 3-D seismic and one exploration well to be drilled. We have satisfied the seismic work obligation.

Catguas Block (100% WI, operated)

We are in a unified phase two and three of five exploration phases. The contract is under suspension due to community issues. This phase requires three exploratory wells to be drilled, or two exploratory wells and re-entry of an existing well, the acquisition of 80 kilometers of 2-D seismic and the relinquishment of 15% of the block. We have satisfied the seismic work obligation.

Sinu-1 Block (60% WI, operated)

The contract comprises one exploration phase which requires the completion of regional studies, the acquisition of 478 kilometers of 2-D seismic and one stratigraphic well to be drilled by August 13, 2017. We completed the regional studies and the acquisition 478 kilometers of 2-D seismic, but are required to acquire an additional 80 kilometers of 2-D seismic to satisfy the minimum required investment.

Sinu-3 Block (51% WI, operated)

We are in the first exploration phase. We requested and were granted an extension of this exploration phase to June 11, 2017. This phase requires the completion of regional studies, the acquisition of 488 kilometers of 2-D seismic and one exploration well to be drilled. We completed the regional studies and the acquisition 334 kilometers of 2-D seismic.

Putumayo-31 Block (100% WI, operated)

We are in phase zero, the community consultation phase. We requested and were granted an extension of this phase to March 2, 2016. We have requested an additional extension of this phase. Subsequent to year-end, we acquired the remaining 35% WI in this block in the Petroamerica acquisition.

Putumayo-4 Block (70% WI, operated)

We are in the first exploration phase. We requested and were granted an extension of this phase to August 17, 2016. This phase requires the acquisition, processing and interpretation of 143 kilometers of 2-D seismic, and one exploration well to be drilled.

Azar, Magdalena and Sierra Nevada Blocks

We have applied to the ANH to relinquish our interest in these blocks. These relinquishments are subject to receipt of final documentation from ANH.

Blocks acquired in the Petroamerica and PGC Acquisitions

We acquired interests in the following blocks through the acquisitions of Petroamerica and PGC on January 13, 2016, and January 25, 2016, respectively.

Putumayo-7 Block (subject to regulatory approval, 100% WI, operator)

Petroamerica and PGC have each entered into agreements to acquire 50% WI in this block, for a total combined WI of 100%. These WI assignments are subject to regulatory approval. This block is in phase one of two exploration phases, which will end on July 31, 2016. This phase requires the acquisition of 167 square kilometers of 3-D seismic and two explorations well to be drilled.

Putumayo-2 Block (100% WI, operator)

We are in the second exploration phase, which is currently suspended. This phase requires two exploration wells to be drilled and the acquisition of 10 square kilometers of 3-D seismic. The seismic work obligation was satisfied prior to our acquisition of Petroamerica.

Llanos-10 (50% WI, non-operated)

We are in the first of two exploration phases. This phase will end on June 18, 2016, and requires the acquisition of 127 square kilometers of 3-D seismic and one exploration well to be drilled. The seismic work obligation was satisfied prior to our acquisition of Petroamerica.

Llanos-19 (50% WI, non-operated)

We are in the second exploration phase. This phase will end on June 12, 2016, and requires two exploration wells to be drilled. One exploration well was drilled in this exploration phase prior to our acquisition of Petroamerica, which resulted in an oil discovery.

Los Ocarros (50% WI, non-operated)

We are in the second additional exploration program which will end on November 12, 2017. The second additional exploration program required one exploration well to be drilled. This work obligation was satisfied prior to our acquisition of Petroamerica.

CPO-7 (20% WI, non-operated)

We are in the second exploration phase. This phase will end on April 13, 2017, and requires the acquisition of 100 kilometers of 2-D seismic and two explorations well to be drilled. The seismic work obligation was satisfied and one of the two work obligation wells was drilled prior to our acquisition of Petroamerica. We are also in an evaluation program which will end January 1, 2017, and requires the recompletion of a well.

CPO-13 (20% WI, non-operated)

We are in the second exploration phase. This phase will end on July 13, 2017, and requires three exploration wells to be drilled. All of the work obligations in this phase were satisfied prior to our acquisition of Petroamerica. We are also in an evaluation program which will end on September 27, 2016, and requires the interpretation of 106 square kilometers of 3-D seismic inversion processing and a long-term test on a well that was drilled prior to the Petroamerica acquisition.

El Porton (25% WI, non-operated)

Prior to our acquisition of Petroamerica, Petroamerica's two other partners on this block withdrew from the exploration phase of the contract and decided not to continue into the fifth exploration phase. As a result, Petroamerica retains 100% WI of the exploration phase of this block. The fifth exploration phase of the contract ended on January 2, 2016, however, we have applied for an extension of this phase. This phase requires one exploration well to be drilled.

Tinigua (50% WI, operator)

We are in the second of six exploration phases which will end on October 20, 2016. This phase requires one exploration well to be drilled.

Alea 1848-A (50% WI, non-operated)

We are in the unified three and four of five exploration phases, which is currently suspended. This phase requires the reprocessing of 52 kilometers of 2-D seismic, the acquisition of 70 kilometers of 2-D seismic, the acquisition of 52 square kilometers of 3-D seismic and one exploration well to be drilled. The work obligation for the reprocessing of 2-D seismic was satisfied prior to our acquisition of Petroamerica.

Alea 1947-C (49.5% WI, non-operated)

We are in phase two of five exploration phases, which is currently suspended. This phase requires one exploration well to be drilled.

El Eden Block (40% WI, non-operated)

The exploration period in the El Eden Block has ended. We retain the La Casona Evaluation Area. The evaluation period for this area will end on April 17, 2016. All work obligations in relation to this contract were completed prior to our acquisition of Petroamerica.

Suroriente Block (15.8% WI, non-operated)

All work obligations in relation to this contract were completed prior to our acquisition of Petroamerica. This is a “Crude Incremental Production Contract” with Ecopetrol. Under the terms of the contract, the working interests are subject to an “R” factor which can reduce the net WI depending on future investment and cash flow ratios. Although the contract is described as an incremental production contract, in this particular case, the working interest parties share in the entire amount of the crude production with Ecopetrol, due to the base production level being set at zero over the life of the contract, which expires in 2023.

Arjona Block (50% WI, non-operated)

This is a contract for the operation of Ecopetrol undeveloped discovered fields. The evaluation period in the Arjona Block has ended. All work obligations in relation to such evaluation period were completed prior to our acquisition of Petroamerica. We entered into an agreement to transfer our working interest in this block to a third party, but this assignment is subject to Ecopetrol approval.

El Balay

Prior to our acquisition of Petroamerica, Petroamerica applied to the ANH to relinquish its interest in this block. This relinquishment is subject to receipt of final documentation from ANH.

Royalties

Colombian royalties are regulated under laws 756 of 2002 and 1530 of 2012. All discoveries made subsequent to the enactment of law 756 of 2002 have the sliding scale royalty described below. Discoveries made before the enactment of this law have a royalty of 20%. The ANH contracts to which we are a party all have royalties that are based on a sliding scale described in law 756. This royalty works on an individual oil field basis starting with a base royalty rate of 8% for gross production of less than 5,000 bopd. The royalty increases in a linear fashion from 8% to 20% for gross production between 5,000 and 125,000 bopd and is stable at 20% for gross production between 125,000 and 400,000 bopd. For gross production between 400,000 and 600,000 bopd the rate increases in a linear fashion from 20% to 25%. For gross production in excess of 600,000 bopd the royalty rate is fixed at 25%. In addition to the sliding scale royalty, the following blocks have additional x-factor royalties: Llanos-22 and Putumayo-7: 1%; Sinu-1 and Llanos-10: 3%; Putumayo-31: 12%; Sinu-3:17%; CPO-13: 32% and CPO-7: 47%.

For gas fields, the royalty is on an individual gas field basis starting with a base royalty rate of 6.4% for gross production of less than 28.5 MMcf of gas per day. The royalty increases in a linear fashion from 6.4% to 20% for gross production between 28.5 MMcf of gas per day and 3.42 Bcf of gas per day and is stable at 16% for gross production between 712.5 to 2,280 MMcf of gas per day. For gross production between 2.28 to 3.42 Bcf of gas per day the rate increases in a linear fashion from 16% to 20%. For gross production in excess of 3.42 Bcf of gas per day the royalty rate is fixed at 20%.

Pursuant to the Chaza Block exploration and production contract (the "Chaza Contract") between the ANH and Gran Tierra, our production from the Costayaco Exploitation Area is also subject to an additional royalty (the "HPR royalty") that applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. Pursuant to the Chaza Contract, any new Exploitation Area on the Chaza Block will also be subject to the HPR royalty once the production on such Exploitation Area exceeds five MMbbl of cumulative production. The Jilguero Exploitation Area in the Garibay Block will be subject to the HPR royalty once production from such Exploitation Area has reached five MMbbl.

There is a dispute with the ANH as to whether the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area or only after production from the Moqueta Exploitation Area has reached five MMbbl (see Item 3. “Legal Proceedings” and Item 8. "Financial Statements and Supplementary Data", below). On April 30, 2015, total cumulative production from the Moqueta Exploitation Area reached 5.0 MMbbl and Gran Tierra commenced paying the HPR royalty payable on production over that threshold. The estimated compensation which would be payable on cumulative production if the ANH's claims are accepted in the arbitration is $66.3 million plus related interest of $26.5 million. We also disagree with the interest rate that the ANH has used in calculating the interest cost. We assert that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be

three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum.
At December 31, 2015, based on an interest rate of three-month LIBOR plus 4% related interest would be $6.4 million.

For exploration and production contracts awarded in the 2010, 2012 and 2014 Colombia Bid Rounds, the HPR royalty will apply once the production from the area governed by the contract, rather than any particular Exploitation Area designated under the contract, exceeds five MMbbl of cumulative production. We expect that this criterion for the HPR royalty will apply for subsequent bid rounds.

The Guayuyaco Block has the sliding scale royalty but does not have the additional royalty.

In addition to these government royalties, our original interests in the Santana, Guayuyaco, Chaza and Azar Blocks acquired on our entry into Colombia in 2006 are subject to a third party royalty. The additional interests in Guayuyaco and Chaza that we acquired on the acquisition of Solana in 2008 are not subject to this third party royalty. On June 20, 2006, we entered into a participation agreement that would effectively compensate Crosby Capital, LLC ("Crosby") for its share in certain Colombian properties. The compensation is in the form of overriding royalty rights that apply to our original interests in production from the Santana, Guayuyaco, Chaza and Azar Blocks. The overriding royalty rights start with a 2% rate on working interest production less government royalties. For new commercial fields discovered within 10 years of the agreement date and after a prescribed threshold is reached, Crosby reserves the right to convert the overriding royalty rights to a net profit interest ("NPI"). This NPI ranges from 7.5% to 10% of working interest production less sliding scale government royalties, as described above, and operating and overhead costs. No adjustment is made for the HPR royalty. On certain pre-existing fields, Crosby does not have the right to convert its overriding royalty rights to an NPI. In addition, there are conditional overriding royalty rights that apply only to the pre-existing fields. Currently, we are subject to a 10% NPI on 50% of our working interest production from the Costayaco and Moqueta Fields in the Chaza Block and 35% of our working interest production from the Juanambu Field in the Guayuyaco Block, and overriding royalties on our working interest production from the Santana Block and the Guayuyaco Field in the Guayuyaco Block.

The Putumayo-7 Block is also subject to a third party royalty in addition to the government royalties. Pursuant to the terms of the agreement by which the interests in the Putumayo-7 Block were acquired, a 10% royalty on production from the Putumayo-7 Block is payable to Petro Caribbean Resources Ltd. ("PCR"). The terms of the royalty allow for transportation costs, marketing and handling fees, government royalties (including royalties payable to the ANH pursuant to Section 39 of the contract for the Putumayo-7 Block - the "Rights Due to High Prices") and taxes (other than taxes measured by the income of any party, and other than VAT or any equivalent) to be paid in cash or kind to the Government of Colombia (or any federal, state, regional or local government agency) and ANH, and the 1% ’X’ factor payment to be deducted from production revenue prior to the royalty being paid to PCR.

Oil and Gas Properties - Brazil

We have interests in seven blocks in Brazil and are the operator in all of these blocks. Our Brazilian properties are located in the Recôncavo Basin in Eastern Brazil in the State of Bahia.

All of our blocks in Brazil are subject to an 11% royalty, which consists of a 10% crown royalty and a 1% landowner royalty.

Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 (100% WI, operated)

Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 are located approximately 70 kilometers northeast of Salvador, Brazil in the Recôncavo Basin and cover 27,076 gross acres. The Tiê Field on Block 155 includes two productive wells.

In December 2014, the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") issued an injunction specifically related to properties in the Recôncavo Basin covered by Bid Round 12. This injunction placed a moratorium on unconventional activities on the Bid Round 12 blocks, all of which were unconventional exploration targets, until such a time as policies governing unconventional activities are finalized. Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 were granted in Bid Round 9, for which there has not been a similar injunction; however, we expect that the ANP’s injunction may limit our ability to receive permits in the short-term for our blocks with unconventional exploration targets.

The First Appraisal Plan ("PAD") phase for Blocks REC-T-129, REC-T-142 and REC-T-155 ended on May 24, 2015, however we requested and were granted a suspension of the PAD phase until regulatory policies governing unconventional activities are finalized.

The exploration phase of the concession agreement on Block REC-T-224 was due to expire on December 11, 2013; however, we requested and were granted a suspension of the exploration phase of this block. The exploration phase on Block REC-T-224 will end one year after the date an environmental permit is granted. This phase requires one exploration well to be drilled.

Blocks REC-T-86, REC-T-117 and REC-T-118 (100% WI, operated)

Blocks REC-T-86, REC-T-117 and REC-T-118 are located north of our other blocks in the Recôncavo Basin and cover 20,658 gross acres. All three blocks are in the first exploration phase which will end in August 2016. This phase requires the acquisition of a total of 120 square kilometers of 3-D seismic on the three blocks and two exploration wells to be drilled on Block REC-T-117 and three exploration wells on Block REC-T-118. We have satisfied the work obligation for the acquisition, processing and interpretation of 3-D seismic on Block 86. We have requested a rephasing of the work obligations for the exploration commitments on Blocks 117 and 118 that would move the obligations to 2017.

Oil and Gas Properties - Peru

We have a 100% WI in five blocks in Peru and we are the operator in each of the blocks. The following table provides summary information for our blocks in Peru:

Block	Acres, Gross and Net
Block 95	853,210
Block 123	2,323,831
Block 129	1,167,409
Block 107	623,504
Block 133	764,320
	5,732,274

All blocks in Peru are subject to a license agreement with PeruPetro. There is a 5-20% sliding scale royalty rate on the lands, dependent on production levels. Production less than 5,000 bopd is assessed a royalty of 5%. For production between 5,000 and 100,000 bopd there is a linear sliding scale between 5% and 20%. Production over 100,000 bopd has a flat royalty of 20%. This royalty structure applies to all blocks in Peru in which we have an interest. Block 133 has an additional royalty 'X' factor of 15%.

Status of Exploration Phases

Block 95 (100% WI, operated)

As previously discussed, in February 2015, we ceased all further development expenditures in the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security. We applied for and were granted a three year retention period from December 28, 2015, to ring-fence the Bretaña Structure. The obligation during this retention period is to evaluate the economics of the project in order to decide whether to declare commerciality by December 27, 2018. Additionally, we were granted an extension of the exploration period to December 27, 2017. This additional exploration period requires the completion of 176 units of work to move to the next phase or forfeiture with no penalty or commitment.

Block 123 and Block 129 (100% WI, operated)

Both blocks are in the third exploration period of five and are under force majeure. On Block 123, the current exploration period required one exploration well to be drilled or the completion of 300 units of work. This work obligation was satisfied by the acquisition of 318 kilometers of 2-D seismic prior to assuming operatorship. On Block 129, the current exploration period required one exploration well to be drilled or the completion of 204 units of work. This work obligation was satisfied by the acquisition of 252 kilometers of 2-D seismic by our former partners on this block.

Block 107 (100% WI, operated)

We are in the fifth and final exploration period, which is suspended due to delays in the permitting process. A 3-year extension of the fifth exploration phase was granted in April 30th, 2015. This period requires two exploration wells to be drilled. During 2015, we completed the acquisition of 311 kilometers of 2-D seismic as part of the obligation for the fourth exploration period.

Block 133 (100% WI, operated)

We are in the third exploration period of four, which is in force majeure pending the approval of 2-D seismic and drilling EIAs. This period requires one exploration well to be drilled or the completion of 200 units of work.

Administrative Facilities

Our principal executive offices are located in Calgary, Alberta, Canada. The Calgary office lease will expire on December 30, 2018. We also have office space in Colombia, Peru and Brazil.

Estimated Reserves

Our 2015 reserves were independently prepared by McDaniel International Inc. ("McDaniel"), a wholly owned subsidiary of McDaniel & Associates. McDaniel & Associates was established in 1955 as an independent Canadian consulting firm and has been providing oil and gas reserves evaluation services to the world's petroleum industry for the past 60 years. They have internationally recognized expertise in reserves evaluations, resource assessments, geological studies, and acquisition and disposition advisory services. McDaniel’s has offices in Calgary, Canada and Guildford, United Kingdom, The technical person primarily responsible for the preparation of our reserves estimates at McDaniel meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The primary internal technical person in charge of overseeing the preparation of our reserve estimates is the Vice President, Asset Management. He has a B. Eng (Hons) degree in mechanical engineering and is a professional engineer and member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He is responsible for our engineering activities including reserves reporting, asset evaluation, reservoir management and field development. He has over 20 years of experience working internationally in the oil and gas industry.

We have developed internal controls for estimating and evaluating reserves. Our internal controls over reserve estimates include: 100% of our reserves are evaluated by an independent reservoir engineering firm, at least annually; and review controls are followed, including an independent internal review of assumptions used in the reserve estimates and presentation of the results of this internal review to our reserves committee. Calculations and data are reviewed at several levels of the organization to ensure consistent and appropriate standards and procedures. Our policies are applied by all staff involved in generating and reporting reserve estimates including geological, engineering and finance personnel.

The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. “Risk Factors”. The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. Therefore, the accuracy of the reserve estimate is dependent on the quality of the data, the accuracy of the assumptions based on the data and the interpretations and judgment related to the data.

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Estimates of proved reserves are generated through the integration of relevant geological, engineering, and production data, utilizing technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us.

Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

The following table sets forth our estimated reserves NAR as of December 31, 2015.

Reserves Category	Oil (Mbbl)	Natural Gas (MMcf)	Oil and Natural Gas (MBOE)
Proved			
Developed			
Colombia	28,513	1,346	28,737
Brazil	2,303	1,368	2,531
Total proved developed reserves	30,816	2,714	31,268
Undeveloped			
Colombia	4,873	477	4,953
Brazil	2,420	1,437	2,659
Total proved undeveloped reserves	7,293	1,914	7,612
Total proved reserves	38,109	4,628	38,880
Probable			
Developed			
Colombia	7,354	514	7,440
Brazil	651	386	715
Total probable developed reserves	8,005	900	8,155
Undeveloped			
Colombia	5,319	557	5,412
Brazil	1,952	1,159	2,145
Total probable undeveloped reserves	7,271	1,716	7,557
Total probable reserves	15,276	2,616	15,712
Possible			
Developed			
Colombia	6,044	530	6,132
Brazil	563	334	619
Total possible developed reserves	6,607	864	6,751
Undeveloped			
Colombia	3,860	508	3,945
Brazil	1,688	1,002	1,855
Total possible undeveloped reserves	5,548	1,510	5,800
Total possible reserves	12,155	2,374	12,551

Product Prices Used In Reserves Estimates

The product prices that were used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions and/or distance from market. The average realized prices for reserves in the report are:

Oil and NGLs (USD/bbl) - Colombia	$43.96
Natural Gas (USD/Mcf) - Colombia	$3.55
Light/Medium Oil (USD/bbl) - Brazil	$40.57
Natural Gas (USD/Mcf) - Brazil	$1.47

Proved Undeveloped Reserves

At December 31, 2015, we had total proved undeveloped reserves NAR of 7.6 MMBOE (December 31, 2014 - 7.7 MMBOE), including 5.0 MMBOE in Colombia (December 31, 2014 – 6.2 MMBOE) and 2.6 MMBOE in Brazil

(December 31, 2014 –

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1.5 MMBOE). Approximately 53%, 7% and 5% of proved undeveloped reserves, respectively, are located in our Moqueta, Costayaco and Ramiriqui Fields in Colombia and 35% are in the Tiê Field in Brazil. None of our proved undeveloped reserves at December 31, 2015, have remained undeveloped for five years or more since initial disclosure as proved reserves and we have adopted a development plan which indicates that the proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure as proved reserves.

Material changes in proved undeveloped reserves are summarized in the table below:

	Oil Equivalent (MMBOE)
Balance, December 31, 2014	$7.7
Converted to proved producing	(1.3)
Discoveries and extensions	0.6
Technical revisions	0.6
Balance, December 31, 2015	$7.6

In 2015, we converted 1.3 MMBOE, or 17% of year-end 2014 proved undeveloped reserves, to developed status. In 2015, we made investments, consisting solely of capital expenditures, of $34.6 million in Colombia and $0.1 million in Brazil, associated with the development of proved undeveloped reserves.

All of the proved undeveloped reserves conversions occurred in the Costayaco, Moqueta and Jilguero Fields in Colombia. In Colombia, the majority of proved undeveloped conversions occurred as a result of ongoing development activities in the Moqueta and Costayaco Fields, including infill drilling and a pressure maintenance projects in both of these fields.

Discoveries and extensions include proved undeveloped reserves additions in Brazil as a result of the signing of a gas contract and proved undeveloped reserves additions in Colombia at one location in the Ramiriqui Field. Technical revisions include positive revisions resulting from better than expected production performance in the Costayaco and Moqueta Fields. In Brazil, no new wells were drilled, however, our current development plan includes a water injection project and the updated reservoir modeling resulted in a large technical revision to the proved ultimate recovery volumes of the existing wells.

Production, Revenue and Price History

Certain information concerning production, prices, revenues and operating expenses for the three years ended December 31, 2015, is set forth in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and in the Unaudited Supplementary Data provided following our Financial Statements in Item 8, which information is incorporated by reference here.

The following table presents oil and NGL production NAR from our Costayaco and Moqueta Fields for the three years ended December 31, 2015:

	Year Ended December 31,					
	2015		2014		2013	
	Costayaco	Moqueta	Costayaco	Moqueta	Costayaco	Moqueta
Oil and NGL's, bbl	4,053,977	2,005,444	4,194,933	1,690,335	4,692,610	1,283,369
Average sales price of oil and NGL's per bbl	$42.57	$42.10	$83.05	$82.84	$90.13	$97.22
Operating expenses of oil and NGL's per bbl	$14.87	$15.93	$15.50	$12.06	$11.29	$16.58

We prepared the estimate of standardized measure of proved reserves in accordance with the Financial Accounting Standards Board (“FASB”) Accounting Standards Codification 932, “Extractive Activities – Oil and Gas”.

Drilling Activities

The following table summarizes the results of our exploration and development drilling activity for the past three years. Wells labeled as "In Progress" for a year were in progress as of December 31, 2015, 2014 or 2013. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to Gran Tierra of productive wells compared to the costs of dry holes.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	—	—	—	—	3.00	1.60
Dry	1.00	1.00	2.00	2.00	1.00	0.50
In Progress	—	—	1.00	1.00	2.00	2.00
Development						
Productive	7.00	5.16	6.00	6.00	5.00	5.00
Dry	—		—	—	—	—
In Progress	6.00	6.00	3.00	3.00	—	—
Total Colombia	14.00	12.16	12.00	12.00	11.00	9.10
Brazil						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	2.00	2.00	2.00	2.00
In Progress	—	—	—	—	2.00	2.00
Development						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Total Brazil	—	—	2.00	2.00	4.00	4.00
Peru						
Exploration						
Productive	—	—	—	—	1.00	1.00
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Development						
Productive	—	—	—	—	—	—
Service	1.00	1.00	—	—	—	—
Dry	1.00	1.00	—	—	—	—
In Progress	—	—	1.00	1.00	—	—
Total Peru	2.00	2.00	1.00	1.00	1.00	1.00
Argentina[1]						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	3.00	1.70
In Progress	—	—	—	—	—	—
Development						

Productive	—	—	1.00	0.85	4.00	3.35
Dry	—	—	—	—	1.00	0.35
In Progress	—	—	1.00	1.00	1.00	1.00
Total Argentina	—	—	2.00	1.85	9.00	6.40
Total	16.00	14.16	17.00	16.85	25.00	20.50

(1) On June 25, 2014, we sold our Argentina business unit to Madalena Energy Inc. ("Madalena").

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Of the four wells in progress in Colombia as at December 31, 2014, two continued to be in progress (suspended), one was producing and one was dry at December 31, 2015. We had one well in progress in Peru as at December 31, 2014, which was dry at December 31, 2015.

In 2015, we also continued pressure maintenance projects in the Costayaco and Moqueta Fields in Colombia.

Well Statistics

The following table sets forth our productive wells as of December 31, 2015:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia(1)	40.0	34.6	—	—	40.0	34.6
Brazil(2)	2.0	2.0	—	—	2.0	2.0
Peru	1.0	1.0	—	—	1.0	1.0
	43.0	37.6	—	—	43.0	37.6

(1) Includes 9.0 gross and 8.4 net water injector wells and 43.0 gross and 39.5 net wells with multiple completions.
(2) Includes 2.0 gross and net wells with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2015:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia(1)	180,349	121,867	3,216,195	2,652,763	3,396,544	2,774,630
Brazil	1,511	1,511	46,223	46,223	47,734	47,734
Peru	—	—	5,732,274	5,732,274	5,732,274	5,732,274
Gran Tierra as at December 31, 2015(1)	181,860	123,378	8,994,692	8,431,260	9,176,552	8,554,638
Combined Petroamerica and PGC(2)	1,514,477	386,108	794,545	554,600	2,309,022	940,708
Pro forma as at December 31, 2015(3)	1,696,337	509,486	9,789,237	8,985,860	11,485,574	9,495,346

(1) Excluded from acres are three blocks for which government approval of relinquishments was pending as of December 31, 2015. These blocks total 820,189 gross and net acres in Colombia.

(2) We acquired Petroamerica and PGC subsequent to December 31, 2015.

(3) Gives pro forma effect to the acquisitions of Petroamerica and PGC as if they had occurred on December 31, 2015.

At December 31, 2015, our gross undeveloped acreage was located 64% in Peru (39% Blocks 123 and 129) and 36% in Colombia.

Research and Development

We utilize existing technology, industry best practices and continual process improvement to execute our business plan. We have not expended any resources on pursuing research and development initiatives.

Marketing and Major Customers

Colombia

Our oil in Colombia is light oil, with 93% of 2015 production coming from the Putumayo Basin with an average API of approximately 29°.

We have entered into agreements to sell to Ecopetrol the volume of crude oil production produced in the Chaza and Guayuyaco Blocks (the “Putumayo production”). The volume of crude oil does not include the volume of oil corresponding to royalties taken in kind, but does include volumes relating to HPR royalties. These agreements are subject to renegotiation annually and generally contain mutual termination provisions with 30 days notice. These agreements will expire November 30, 2016. We may, but are not obligated to, sell up to 100% of our Putumayo production to Ecopetrol. We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and trucking and through the transportation and logistics assets of Ecopetrol and CENIT Transporte y Logistica de Hidrocarburos S.A.S ("CENIT"), a wholly-owned subsidiary of Ecopetrol.

The point of sale of our Putumayo production to Ecopetrol is the Port of Tumaco on the Pacific coast of Colombia.

We have entered into transportation agreements (the “Transportation Agreements”) with CENIT. These agreements will expire November 30, 2016. Pursuant to the Transportation Agreements we pay a transportation tariff and transportation tax for the transportation of the Putumayo production from the Putumayo Basin to the Port of Tumaco. Pursuant to the Transportation Agreements, each of Gran Tierra Energy Colombia Ltd. and Petrolifera Petroleum (Colombia) Limited have the right to transport up to 10,000 bopd, subject to availability of capacity, of crude oil production from the Chaza and Guayuyaco Blocks in Colombia: (1) from Santana Station to CENIT’s facility at Orito through CENIT’s Mansoya – Orito Pipeline, and (2) from CENIT’s facility at Orito to the Port of Tumaco through CENIT’s Orito – Tumaco Pipeline. We can request that CENIT transport additional crude oil in excess of 20,000 bopd through the pipelines on the same terms, which CENIT may do at its sole discretion.

Generally, under these agreements, CENIT is liable (subject to specified limitations) for pollution clean up costs resulting from incidents during transportation. The cost of oil lost during transportation is shared by the parties that ship oil on the pipeline, in proportion to their share of total volumes shipped.

Currently we have Firm Capacity Transportation Agreements for 6,000 bopd, of which 3,000 bopd are under ship or pay agreements and 3,000 bopd are under ship and pay agreements. These agreements will expire October 31, 2020. The remainder of our Putumayo production is transported through the Transportation Agreements.

In the event that we do not sell all of our production to Ecopetrol, we sell to numerous alternative purchasers. We are under no obligation to sell any oil to our alternative purchasers until we specify for a particular day the amount of oil we wish to sell to them. Oil can be delivered and sold at the Costayaco battery where oil is loaded into trucks, delivered to facilities at Babillas Station and the sales point is the Port of Coveñas upon oil export, or delivered via pipeline to the Port of Esmeraldas, Ecuador and the sales point is when oil is loaded into an export tanker.

The majority of the oil produced is transported by pipeline. Varying amounts of oil are trucked: (1) from Santana Station to Ecopetrol’s storage terminal at Orito, a distance of approximately 46 kilometers; (2) from the Costayaco Field to Ecopetrol’s storage terminal at Neiva (Dina Station), approximately 350 kilometers north of the Chaza Block; (3) from the Costayaco Field to Hocol´s unloading facilities at Neiva (Babillas Station), approximately 350 kilometers north of the Chaza Block; (4) from the Costayaco Field to the Atlántico Oil Terminal in Barranquilla, a distance of approximately 1,500 kilometers; (5) from the Garibay Jilguero Field to facilities at Cusiana Station, a distance of approximately 75 kilometers; and; (6) from the Llanos 22 Ramiriqui Field to facilities at Cusiana Station, a distance of approximately 35 kilometers.

We receive revenues for our Colombian oil sales in U.S. dollars. Oil prices for sales of our crude oil are defined by agreements with the purchasers of the oil and are based generally on an average price for crude oil, such as West Texas Intermediate ("WTI") or Brent, with adjustments such as for quality, specified fees, transportation fees and transportation tax.

Brazil

Petróleo Brasileiro S.A (“Petrobras”) is the main purchaser of our oil production from Block 155 in Brazil. Oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. Oil prices for sales to Petrobras are based on the monthly average Dated Brent price less a refining and quality discount.

Competition

The oil and gas industry is highly competitive. We face competition from both local and international companies in acquiring properties, contracting for drilling and other oil field equipment and securing trained personnel. Many of these competitors, such as Ecopetrol, have financial and technical resources that exceed ours. Others are smaller and we believe our technical and financial capabilities give us a competitive advantage over these companies. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for prospects and resources in the oil and gas industry.

Geographic Information

Information regarding our geographic segments, including information on revenues, assets, expenses and net income, can be found in Note 4 to the Consolidated Financial Statements, Segment and Geographic Reporting, in Item 8 “Financial Statements and Supplementary Data”, which information is incorporated by reference here. 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. "All Other" assets include assets held by our corporate head office in Calgary, Alberta, Canada. Because all of our exploration and development operations are in South America, we face many risks associated with these operations. See Item 1A “Risk Factors” for risks associated with our foreign operations.

Regulation

The oil and gas industry in Colombia, Peru and Brazil 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 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, prior to 2004, Ecopetrol was the administrator of all hydrocarbons and therefore executed contracts with oil companies under different contractual types such as Association Contracts and Shared Risk Contracts. Under an Association Contract, the oil company (“Associate”) assumed all risk during the exploration phase and Ecopetrol had the obligation to reimburse the Associate, if the commerciality was accepted by Ecopetrol, the direct exploration costs which the Associate incurred in proportion to Ecopetrol's working interest. If Ecopetrol did not accept the initial commerciality of a field, the Associate could continue the activities at its sole risk and Ecopetrol would retain the right to back-in later, after Ecopetrol reimbursed the Associate for the initial exploitation work and exploration costs plus certain penalties, depending upon at what stage Ecopetrol later declared commerciality of the field.

Effective June 2003, the regulatory regime in Colombia underwent a significant change with the formation of the ANH. The ANH is now the administrator of the hydrocarbons in the country and therefore is responsible for regulating the Colombian oil and gas industry, including managing all exploration lands. Ecopetrol became a public company owned in majority by the state with the main purpose of exploring and producing hydrocarbons similar to any other oil company. However, Ecopetrol continues to have rights under the existing contracts executed with oil companies before the ANH was created. Ecopetrol continues to be the major purchaser and marketer of oil in Colombia and operates the majority of the oil transportation infrastructure in the country.

In conjunction with this change, the ANH developed a new exploration risk contract that took effect as of June 2004. This Exploration and Production Contract has significantly changed the way the industry views Colombia. In place of the earlier association contracts, 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 tax regulations. Each contract contains an exploration phase and a production phase. The exploration phase will contain a number of exploration periods and each period will have an associated work commitment. The production phase will last a number of years (usually 24) from the declaration of a commercial hydrocarbon discovery.

We operate in Colombia through the following branches - Gran Tierra Energy Colombia Ltd., Petrolifera Petroleum (Colombia) Limited, Petroamerica International Colombia Corp. Sucursal, Petroamerica Energy Colombia Sucursal, Petroamerica P&G Corp Colombia, Southeast Investment Corporation, Petroamerica Colombia, and PetroGranada Colombia Limited Sucursal Colombia. The home offices of Gran Tierra Energy Colombia Ltd., Petrolifera Petroleum (Colombia) Limited, Petroamerica Colombia and Petroamerica Energy Colombia Sucursal are qualified as operators of oil and gas properties by the ANH.

When operating under a contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, except for royalty volumes which are collected by the ANH (or its designee), depending on the type of contract. The contractor can market the hydrocarbons in any manner whatsoever, subject to a limitation in the case of natural emergencies where the law specifies the manner of sale.

Peru

Peru's hydrocarbon legislation, which includes the Organic Hydrocarbon Law No. 26221 enacted in 1993 and the regulations thereunder (the "Organic Hydrocarbon Law"), governs our operations in Peru. This legislation covers the entire range of petroleum operations, defines the roles of Peruvian government agencies which regulate and interact with the oil and gas industry, provides that private investors (either national or foreign) may also make investments in the petroleum sector and provides for the promotion of the development of hydrocarbon activities based on free competition and free access to all economic activities. This law provides that pipeline transportation and natural gas distribution must be handled via concession contracts with the appropriate governmental authorities. All other petroleum activities are to be freely operated subject to complying with applicable regulation, including local safety and environment standards.

Under the Peruvian legal system, Peru is the owner of the hydrocarbons located below the surface in its national territory. However, Peru has given the ownership right to extracted hydrocarbons to PeruPetro S.A. ("PeruPetro"), a state company responsible for promoting and overseeing the investment of hydrocarbon exploration and exploitation activities in Peru. PeruPetro is empowered to enter into contracts for either the exploration and exploitation or just the exploitation of petroleum and natural gas on behalf of Peru, the nature of which are described further below. The Peruvian government also plays an active role in petroleum operations through various entities and agencies, including through the involvement of the Ministry of Energy and Mines(the specialized government department in charge of establishing energy, mining and environmental protection policies, enacting the rules applicable to all these sectors and supervising compliance with such policies and rules),OSINERGMIN (an agency in charge of checking compliance with hydrocarbon regulations) and OEFA (the entity of supervising environmental compliance). We are subject to the laws and regulations of all of these entities and agencies.

The Peruvian Constitution and the Organic Hydrocarbon Law states that a license contract does not provide for a transfer or lease of property over the area of the exploration or exploitation. In accordance with a license contract, a third party acquires the right to explore for or exploit hydrocarbons in a specified area and PeruPetro (the entity that holds the Peruvian state interest) transfers the property right in the extracted hydrocarbons to the third party, who must pay a royalty to the state.

PeruPetro enters into either license contracts or service contracts for hydrocarbon exploration and exploitation. Peruvian law also allows for other contract models, but the investor must propose contract terms compatible with Peru's interests. We only operate under license contracts and do not foresee operating under any service contracts. License and service contracts are approved by supreme decree issued by the Peruvian Ministry of Economy and Finance and the Peruvian Ministry of Energy and Mining, and can only be modified by written agreement signed by the parties. A company must be qualified by PeruPetro to enter into negotiations for hydrocarbon exploration and exploitation contracts in Peru. In order to qualify, the company must meet the standards under the Regulations Governing the Qualifications of Oil Companies. These qualifications generally require the company to have the technical, legal, economic and financial capacity to comply with all obligations it will assume under the contract based on the characteristics of the area requested, the possible investments and the environmental protection rules governing the performance of its operations. When a contractor is a foreign investor, it is required to incorporate a subsidiary company or registered branch in accordance with Peruvian corporate law and appoint Peruvian representatives in accordance with the Organic Hydrocarbon Law who will interact with PeruPetro.

We operate in Peru through Gran Tierra Energy Peru S.R.L. and Petrolifera Petroleum del Peru S.R.L. Gran Tierra Energy Peru S.R.L. has been qualified by PeruPetro with respect to its contracts for Blocks 95, 123 and 129 and Petrolifera has been qualified by PeruPetro with respect to its contracts for Blocks 107 and 133.

When operating under a license contract, the licensee is the owner of the hydrocarbons extracted from the contract area during the performance of operations and pays royalties which are collected by PeruPetro. The licensee can market or export the hydrocarbons in any manner whatsoever, subject to a limitation in the case of national emergency where the law stipulates such manner.

Brazil

In Brazil, Law No. 2004 enacted in 1953 created the state monopoly of the petroleum industry and Petrobras, a state-owned legal entity, which was the sole company conducting exploration and production activities in Brazil. The Brazilian Federal Constitution enacted on October 5, 1988, continued this state monopoly of the petroleum industry.

Amendment No. 9 to the Brazilian Constitution, enacted on November 9, 1995, relaxed the state monopoly and authorized the Brazilian government to contract with state and private companies, with head offices and management located in Brazil, for the exploration and production of oil and natural gas, as well as to grant authorizations for the refining, transportation, import and export of oil, natural gas and its by-products.

The regulatory model is governed by Law No. 9478 of August 6, 1997 (the "Petroleum Law"), as amended, which controls the granting of concessions for carrying out exploration and production activities to Brazilian companies. The Petroleum Law, as amended, also established a legal framework for pre-salt layer areas and strategic areas to be defined by the Brazilian government and which will be subject to the Production Sharing Regime.

In accordance with the Petroleum Law, the acquisition of oil and natural gas property and oil and gas operations by state and private companies is subject to legal, technical and economic standards and regulations issued by the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP"), the agency created by the Petroleum Law and vested with regulatory and inspection authority to ensure adequate operational procedures with respect to industry activities and the supply of fuels throughout the national territory.

The ANP has authority for the implementation of the national oil and natural gas policy in accordance with the National Council of Energy Policy. The ANP conducts bid rounds to award exploration, development and production contracts, as well as to authorize the construction and operation of refineries and gas processing units, transportation facilities (including port terminals), import and export of oil and natural gas, as well as supervision of the activities which integrate the petroleum industry and the general enforcement of the Petroleum Law.

During a public bid procedure, any company evidencing technical, financial and legal standards under the applicable bidding requirements may qualify and apply for particular blocks made available for concession contracts. Qualified companies may compete alone or in association with other companies, including through the formation of "consortia" (unincorporated joint-ventures), provided they agree to comply with all the applicable requirements of Brazilian Corporate Law. Blocks awarded and the duration of the exploration and production periods are defined in the contracts which, besides the usual covenants that can be found in oil concessions, such as exploration and development programs, relinquishment of areas, and unitization, include reversion to the state of certain assets at the end of the concession. Contracts may be assigned or transferred to other Brazilian companies that comply with the technical, financial and legal requirements established by the ANP.

Oil and natural gas resources in Brazil, whether onshore or offshore, belong to the Brazilian government. However, under the Concession Regime, after the discovery of oil and gas reserves, ownership is assigned to the concessionaire. Under the principles of the Federal Constitution, the national territory comprises all land and the continental shelf. Brazil is a signatory of the conventions regulating the economic use of the sea and its subsoil. Brazil is thus entitled to the enjoyment of the resources over the territorial sea and marine platform up to the limits indicated in the pertinent treaties.

Concessionaires are required under Law No. 9,478/97 to pay the government dues and fees, in addition to the charges for sale of pre-bid data and information. The ANP has the power to determine the criteria under which the Government Take will be assessed within the limits established by Federal Decree No. 2,705/98. Government Take comprises (i) signature bonus, (ii) royalties, (iii) special participation and (iv) area rentals. Part of the Government

Take is passed on to States and Municipalities and other government branches according to law.

We operate in Brazil through Gran Tierra Energy Brasil Ltda. (“Gran Tierra Brazil”). Gran Tierra Brazil received approval from the ANP as a Class B operator permitting Grant Tierra Brazil to act as an operator both onshore and in the shallow water offshore Brazil.

Environmental Compliance

Our activities are subject to existing laws and regulations governing environmental quality and pollution control in the countries where we maintain operations. Our activities with respect to exploration, drilling, production and facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil and other products, are subject to stringent environmental regulation by local, provincial, state and federal authorities in Colombia, Peru and Brazil. Such regulations relate to environmental impact studies, the discharge of pollutants into air and water, management of hazardous waste, including its transportation, storage, and disposal, permitting for the construction of facilities, recycling requirements and reclamation standards, and the protection of certain plants and animal species, among others. Risks are inherent in oil and gas exploration, development and production operations, such as blowouts, fires, or spills, and significant costs and liabilities may be incurred in connection with environmental compliance issues. Licenses and permits required for our exploration and production activities may not be obtainable on reasonable terms or on a timely basis, which could result in delays and have an adverse effect on our operations. Spills and releases into the environment of petroleum products can result in investigatory and remedial liabilities. Moreover, violations of environmental laws and regulations can result in the issuance of administrative, civil, or criminal fines and penalties, as well as orders or injunctions prohibiting some or all of our operations in affected areas. In addition, indigenous groups or other local organizations could oppose our operations in their communities, potentially resulting in delays which could adversely affect our operations.

We do not expect that the cost of compliance with local, provincial, state and federal provisions which have been enacted or adopted regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment will be material to us.

We have implemented a company wide web-based reporting system which allows us to better track incidents and respective corrective actions and associated costs. We have a Corporate Health, Safety, and Environmental Management System and follow environmental best practices. We have also implemented an environmental risk management program in place as well as waste management procedures. Air and water testing occur regularly and environmental contingency plans have been prepared for all sites and ground transportation of oil. We have a regular quarterly comprehensive reporting system with a schedule of internal audits and routine checking of practices and procedures. Emergency response exercises were conducted in Colombia, Peru and Brazil. However, despite these measures, we cannot guarantee that our operations will always be able to maintain compliance with applicable environmental laws and regulations in the countries in which we operate.

Employees

At December 31, 2015, we had 301 full-time employees (December 31, 2014 - 473): 58 located in the Calgary corporate office, 193 in Colombia (101 staff in Bogota and 92 field personnel), 28 in Peru (19 office staff in Lima and 9 field staff) and 22 in Brazil (9 office staff in Rio de Janeiro and Salvador and 13 field staff). None of our employees are represented by labor unions and we consider our employee relations to be good.

Available Information

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 Exchange Act 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 www.grantierra.com. 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.

In addition, the SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding us. Any materials we have filed with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street N.E. Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

Item 1A. Risk Factors

Risks Related to Our Business

Guerrilla Activity in Colombia Has Disrupted and Delayed, and Could Continue to Disrupt or Delay, Our Operations and We May Be Unable to Safeguard Our Operations and Personnel in Colombia.

During 2012 and 2013, guerrilla activity in Colombia increased significantly, and the activity level remained high in 2014 and 2015. This increased activity creates a greater risk for our operations and our employees.

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

Negotiations between the government and FARC may lead to a peaceful resolution and may not generate the intended outcome for either party. The impact of these negotiations, or any potential resolution, is not determinable on our operations.

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Catatumbo, Cauca, Llanos, Sinu-San Jacinto, Middle Magdalena and Lower Magdalena Basins. Pipelines have been primary targets of guerrilla activity, because such pipelines cannot be adequately secured due to the sheer length of such pipelines and the remoteness of the areas in which the pipelines are laid. The CENIT S.A ("CENIT")-operated Trans-Andean oil pipeline (the "OTA pipeline”), which transports oil from the Putumayo region to the Port of Tumaco and which is one of our export routes, has been targeted by FARC. Starting in 2008, the OTA pipeline experienced outages of various lengths. Since 2012, the OTA pipeline has been shut down for 784 days (including 166 days as a result of landslides and maintenance works). Such disruptions may continue indefinitely and could harm our business.

Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and dissident guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

We Are Vulnerable to Risks Associated with Geographically Concentrated Operations.

Our producing properties are geographically concentrated in Colombia, and as at December 31, 2015, 87% of our proved reserves were located in Colombia. As a result of this concentration, we may be disproportionately exposed to the impact of, among other things, regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation or guerilla activities, transportation constraints or market limitations.

If We do Not Have the Resources to Execute on Our Business Plan, We May Be Required to Curtail Our Operations.

Our base capital program for 2016 is $107 million to fund our exploration and development, which we intend to fund through cash flows from operations and cash on hand. Funding this program relies in part on oil prices remaining close to current levels or higher and other factors to generate sufficient cash flow. In addition to our base 2016 capital program we have a discretionary capital program of $61 million that we may utilize during 2016 if oil prices strengthen during the year. Oil prices were very volatile in 2014 and 2015 and have remained at low levels in the first part of 2016. Low oil prices affect our debt capacity and the amount of money we can borrow using our oil reserves as collateral, as well as the amount of cash we are able to generate from operations. If cash flows from operations are not sufficient to fund our capital program, we may not be able to execute our business plan which would cause us to further decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

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

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

The majority of our oil in Colombia is shipped through the OTA pipeline owned by CENIT and operated by Ecopetrol. Sales of oil have been and could continue to be disrupted by damage to this pipeline or displaced by Ecopetrol's use of the pipeline itself. In addition, CENIT has a monopoly over pipeline transportation from the area and Ecopetrol over the operation of the port of Tumaco, which limits our ability to negotiate proposed pipeline and port tariff increases and our costs may increase as a result. Under our transportation contract with CENIT, the delivery point for our oil is at the end of this pipeline. This creates a risk of loss of oil due to sabotage by guerrillas or theft from the pipeline which may result in reduced revenues and increased clean-up or third party costs. CENIT and Ecopetrol maintain responsibility for clean-up of any spilled oil and for pipeline repair.

If these pipelines remain down for extended periods of time, our storage facilities may become full, which may cause us to limit producing activities. In addition, there is competition for space in these pipelines, and additional discoveries in our area of operations by other companies could decrease the pipeline capacity available to us. Trucking is an alternative to transportation by pipeline; however, it is generally more expensive and carries higher safety risks for us, our employees and the public.

Significant percentages of our 2014 and 2015 production were transported by alternative means. These alternatives are more expensive and reduce our average realized prices. In addition, these alternative means of transportation may not be sustainable long term. When disruptions are of a long enough duration, our sales volumes may be lower than normal, which will cause our cash flow to be lower than normal, and if our storage facilities become full, we can be forced to reduce production.

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

In the event that our cash flow from existing operations and cash on hand is not sufficient, we may require additional capital to fund our currently planned activities or to expand our exploration and development programs to additional properties. We may be unable to obtain additional capital on favorable terms or at all.

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

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

The Borrowing Base Under Our Revolving Credit Facility May Be Reduced in Light of Recent Commodity Price Declines, Which Could Hinder or Prevent us From Meeting Our Future Capital Needs.

The borrowing base under our revolving credit facility is currently $200 million, and lender commitments under our revolving credit facility are $500 million. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is in May 2016. Our borrowing base may decrease as a result of current oil and natural gas price levels, a further decline in oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to current or further declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital market to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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

We operate our business in Colombia, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as nationalization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. Our production in Brazil was shut in for three weeks in October 2013 as a result of a strike by employees of Petrobras which affected the crude oil receiving terminal we use in the Recôncavo Basin, and we experienced minor delays in trucking operations due to demonstrations and strikes in our operating area during the year ended December 31, 2014 and 2015. We do not know how long any such labor action will last, and if it lasts a significant amount of time, it may affect our ability to meet our production targets.

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

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

Recently, in the Department of Putumayo in Colombia where we operate, despite a company’s compliance with legislative requirements for prior consultation of communities and minority ethnic groups and the receipt of the necessary permits to drill and operate, new ethnic groups have been threatening, and in some cases using, the Judicial Branch of the Government, Superior Court of the Judicial District of Mocoa (the “Local Court”) to require that they be consulted, and thereby obtain benefits from companies operating in the Department of Putumayo as a result of those consultations. The Local Court has the ultimate jurisdiction to determine, upon a writ for protection or tutela, by an ethnic group (i) whether there has been a violation of a fundamental right to prior consultation by act or omission of a public authority or individual and (ii) whether the ethnic group is legitimate. If the Local Court determines that there has been a violation and the ethnic group is legitimate despite receipt by the company of its proper governmental permits, the Local Court has the power to invalidate a company’s permits and force the company to cease operations immediately until such time as the company can successfully appeal to the Supreme Court to overturn the Local Court’s decision or prior consultations are completed and the permits effective once again.
Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government and judicial authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired and, if we are faced with a tutela, our operations in the area(s) governed by a Local Court’s order may be shut down for a period of time thereby

causing significant harm to our business in Colombia.

Recently in Brazil, environmental regulations related to fracture stimulation drilling have been under review by national agencies. In December 2014, the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") issued an injunction specifically related to properties in the Recôncavo Basin covered by Bid Round 12. This injunction placed a moratorium on unconventional activities on the Bid Round 12 blocks, all of which were unconventional exploration targets, until such a time as policies governing unconventional activities are finalized. Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 were granted in Bid Round 9, for which there has not been a similar injunction; however, we expect that the ANP’s injunction may limit our ability to receive permits in the short-term for our blocks with unconventional exploration targets. We acquired Blocks REC-T-86, REC-T-117 and REC-T-118 in Bid Round 11 and these blocks may be affected by the same or a similar injunction as the one placed on blocks acquired in Bid Round 12. Until this situation is resolved, the expansion of our drilling operations in Brazil may be limited which would harm our business in Brazil.

Pending regulations related to emissions and the impact of any changes in climate could adversely impact our business.

Governments around the world have become increasingly focused on regulating greenhouse gas ("GHG") emissions and addressing the impacts of climate change in some manner. Brazil, Peru and Colombia all have enacted legislation related to GHG emissions. For example, in July 2015, Colombia announced that it will seek to reduce the national emission of greenhouse gases by at least 20% over the next 15 years. Colombia has also passed legislation requiring the country to generate 77% of its energy from renewable resources and reduce deforestation in the Amazon to zero by 2020. Peru and Brazil have passed similar climate change-related measures.

GHG emissions legislation is emerging and is subject to change. For example, on an international level, almost 200 nations agreed on December 12, 2015, to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that we produce.

Current GHG emissions legislation has not resulted in material compliance costs, however, it is not possible at this time to predict whether proposed legislation or regulations will be adopted, and any such future laws and regulations could result in additional compliance costs or additional operating restrictions. If we are unable to recover a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse impact on our business, financial condition and results of operations. Further, to the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of or access to capital.

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

At December 31, 2015, 92% of our cash and cash equivalents was held by subsidiaries and partnerships outside of Canada and the United States. This cash is generally not available to fund domestic or head office operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay taxes in certain jurisdictions on the distribution of accumulated earnings.

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

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

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

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

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

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

Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations

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

As discussed in Note 11 to the Consolidated Financial Statements in Part II, Item 8 below, our production from the Costayaco Exploitation Area is subject to the HPR royalty, which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which we contested because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. We also believe that the evidence shows that the Costayaco and Moqueta Fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. We supplemented our claim on May 30, 2013. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that we breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. We filed a response to the ANH's counterclaim and filed our comments on the ANH defense to our claim. The ANH filed an amended counterclaim and we filed a response to the ANH's amended counterclaim. In April 2015, total cumulative production from the Moqueta Exploitation Area exceeded 5.0 MMbbl and we commenced paying the HPR royalty. The estimated compensation which would be payable on cumulative production prior to that date if the ANH is successful in the arbitration is $66.3 million plus related interest of $26.5 million. We also disagree with the interest rate that the ANH has used in calculating the interest cost. We assert that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum. At December 31, 2015, based on an interest rate of three-month LIBOR plus 4% related interest would be $6.4 million. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as we do not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH's interpretation is correct could be up to $44.8 million as at December 31, 2015. 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.

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

Our operations have a significant effect on the areas in which we operate. Maintaining good community relationships is an essential aspect of operating in the oil and gas industry. Communities have demonstrated an ability and willingness to halt operations or delay approvals.

To enjoy the support and trust of local populations and governments, we must demonstrate a commitment to: providing local employment, training and business opportunities; a high level of environmental performance; open and transparent communication; a willingness to discuss and address community issues including community development investments that are carefully selected, not unduly costly and bring lasting social and economic benefits to the community and the area. Improper management of these relationships could lead to a delay in operations, loss of license or major impact to our reputation in these communities, which could adversely affect our business.

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

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

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

Our success will depend in large measure on the abilities, expertise, judgment, discretion, integrity and good faith of our executive team and other personnel in conducting our business. The loss of any of these individuals or our inability to attract suitably qualified individuals to replace any of them could materially adversely impact our business.

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

The Acquisitions of Petroamerica and PGC May Not Generate the Results Expected and Could be Difficult to Integrate.

In January 2016, we acquired all of the issued and outstanding shares of Petroamerica and PGC. There can be no assurance that these acquisitions will generate the expected returns and other projected results we anticipate. For example, we may not be able to achieve the anticipated synergies of the acquisitions, including expected increases in revenue and cost savings. If we fail to effectively integrate Petroamerica and PGC, our business and financial results may be adversely affected.

Foreign Currency Exchange Rate Volatility May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. We are also exposed to transaction risk on settlement of payables and receivables denominated in foreign currency. Between January 1, 2014 and February 23, 2016, exchange rates between the Colombian peso and U.S. dollar have varied between 1,844 pesos to one U.S. dollar to 3,440 pesos to one U.S. dollar, a fluctuation of approximately 87%. Production in Brazil is invoiced and paid in Brazilian Reals. Between January 1, 2014 and February 23, 2016, the exchange rate of the

Brazilian Real has varied between 2.19 Reals to one U.S. dollar to 4.18 Reals to the U.S. dollar, a variance of 91%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the Colombian peso weakened by 32% against the U.S. dollar in the year ended December 31, 2015, resulting in a foreign exchange gain.

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

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

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

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

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

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

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

Tax law changes can impact the after tax profits available for expatriation. For example, in the fourth quarter of 2014 the Colombian government approved tax legislation increasing the rate of tax applicable to ordinary income from 34% in 2014 to 39% for 2015, 40% for 2016, 42% for 2017 and 43% for 2018. In the same legislation, the Colombian government also instituted a new “wealth tax” payable on the net equity of our Colombia business units at a rate of 1.15% for 2015, 1% for 2016 and 0.4% for 2017.

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

Peru held a national election in June 2011 after which a new political regime was elected on a left-populist platform. The government has said that the past decade prioritized the strengthening of democracy with economic growth, while the current government will enhance social inclusion to benefit the neediest. This political regime may adopt new policies, laws and regulations that are more hostile toward foreign investment which may result in the imposition of additional taxes, the adoption of regulations that limit price increases, termination of contract rights, or the expropriation of foreign-owned assets. Such actions by the elected political regime could limit the amount of our future revenue in that country and affect our results of operations. The next general elections in Peru will be held on April 10, 2016 and the current incumbent President, Ollanta Humala, will not seek to run again for presidency in this election.

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

The Shining Path Guerilla group has been active in Peru since the early 1980’s and, at one point, was active throughout the country. Recently, the group’s activity has been confined to small areas of Peru and operations have been hampered by the capture of many high profile leaders and membership has fallen dramatically. During April 2012, 30 people working on the Camisea natural gas project in central Peru were kidnapped. Most of the workers were released after a short period of time, and the remainder were freed within a few days. The kidnapping was attributed to the Shining Path Guerilla group. Camisea is a very large, high profile project in an area where the group continues to be active. Our operations in Peru are in a different region, with no known activity by the group. Other groups may be active in other areas of the country and possibly our operational areas. Recently there have been security incidents and incidents of social unrest in and around our operating areas, including Block 107, and activities in the areas surrounding the block are to be considered with caution due to the eradication of illegal farms by the government.

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

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

- expand our systems effectively or efficiently or in a timely manner;
- allocate our human resources optimally;
- identify and hire qualified employees or retain valued employees; or
- incorporate effectively the components of any business that we may acquire in our effort to achieve growth. If we are unable to manage our growth and our operations our financial results could be adversely affected by inefficiencies, which could diminish our profitability.

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

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

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

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

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

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

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

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

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

Our employees have been and will continue to be targeted by parties using fraudulent “spoof” and “phishing” emails to misappropriate information or to introduce viruses or other malware through “trojan horse” programs to our computers. These emails appear to be legitimate emails sent by us but direct recipients to fake websites operated by the sender of the email or request that the recipient send a password or other confidential information through email or download malware. Despite our efforts to mitigate “spoof” and “phishing” emails through education, “spoof” and “phishing” activities remain a serious problem that may damage our information technology infrastructure.

Risks Related to Our Industry

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

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

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs.

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

Estimates of probable and possible reserves are inherently imprecise. When producing an estimate of the amount of oil that is recoverable from a particular reservoir, probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of probable and possible reserves are by their nature much more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

In addition, the quantity and value of our reserves directly effects our ability to access certain kinds of external financing that uses our reserves as collateral. Low oil prices diminish the value of our oil reserves, thus diminishing not only current cash flow, but debt capacity and access to other forms of capital as well. This could impair our ability to carry out the exploration and development activity required to replace our reserves.

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

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. Spot prices for West Texas Intermediate ("WTI") declined from approximately $106 per bbl in June 2014 to less than $30 per bbl in January 2016. The spot price for Brent oil declined from approximately $115 per bbl in June 2014 to less than $30 per bbl in January 2016.

Given the current economic environment and unstable conditions in the Middle East, North Africa, China, and Eastern Europe and the current supply of oil in world markets, the oil price environment is unpredictable and unstable. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations, financing available to us, and quantities of reserves recoverable on an economic basis.

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

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 or at a commercially viable cost. 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. The target location may be drilled again in the future with a revised drilling plan. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations. In addition, changes in the price of oil can affect the commercial success of our exploration activity. If the oil price declines drastically, such as it did at the end of 2014 and beginning of 2015, some projects that were previously considered commercially successful may not be at low oil price levels and may be deferred, which means that our short to medium term production and cash flow may be lower than previously anticipated.

If Oil and Natural Gas Prices Decrease, or Our Operating Results are Different Than We Expect, We May Be Required to Take Write-Downs of the Carrying Value of Our Oil and Natural Gas Properties.

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

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

We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. In addition, environmental and social evaluation demands have increased in Colombia, causing permit processing to take longer than previously experienced in the areas where we operate and, in some areas where we operate, such as the Department of Putumayo, despite the receipt of the proper permits, there are new procedures being utilized by new ethnic communities to make further economic demands on operators to continue to operate in the region, such as the use of the Local Court to obtain a tutela, or writ of protection. These delays and demands are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations.

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

We make estimates of oil and natural gas reserves, upon which we will base our financial projections. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Wells that are drilled may not achieve the results expected from interpretation of geological data. Economic factors beyond our control, such as world oil prices, interest rates and exchange rates, will also impact the value of our reserves. The process of estimating oil and gas reserves is complex, and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

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

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

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

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

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

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 used or 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 likely to 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 force us to curtail our production as a result of restrictions imposed by government regulators, or increase the costs of our production, development or exploration activities because of increased compliance costs.

Penalties We May Incur Could Impair Our Business.

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

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

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

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

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

Challenges to Our Properties May Impact Our Financial Condition.

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

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

If our property rights are reduced, whether by governmental action or third party challenges, our ability to conduct our exploration, development and production may be impaired. See the risk factor "Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations" for a description of our dispute with the ANH regarding royalties payable on our Chaza Block and the resulting challenge to our contract for that block.

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

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

Risks Related to Our Common Stock

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

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

- dilution caused by our issuance of additional shares of Common Stock and other forms of equity securities, which we expect to make in connection with acquisitions of other companies or assets;
- announcements of new acquisitions, reserve discoveries or other business initiatives by our competitors;
- fluctuations in revenue from our oil and natural gas business;
- changes in the market and/or WTI or Brent price for oil and natural gas commodities and/or in the capital markets generally, or under our credit agreement;
-

changes in the demand for oil and natural gas, including changes resulting from the introduction or expansion of alternative fuels;

- changes in the social, political and/or legal climate in the regions in which we will operate;

- changes in the valuation of similarly situated companies, both in our industry and in other industries;

- changes in analysts’ estimates affecting us, our competitors and/or our industry;

- changes in the accounting methods used in or otherwise affecting our industry;

- changes in independent reserve estimates related to our oil and gas properties;

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

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

- quarterly variations in our revenues and operating expenses; and
- additions and departures of key personnel.
- updated reserve estimates by independent parties.

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

As discussed above (see “Royalties”, above, in Item 1), Gran Tierra’s production from the Costayaco Exploitation Area is subject to the HPR royalty, which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta Fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. Gran Tierra supplemented its claim on May 30, 2013. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH defense to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. On April 30, 2015, total cumulative production from the Moqueta Exploitation Area reached 5.0 MMbbl and Gran Tierra commenced paying the HPR royalty payable on production over that threshold. The estimated compensation which would be payable on cumulative production if the ANH's claims are accepted in the arbitration is $66.3 million plus related interest of $26.5 million. We also disagree with the interest rate that the ANH has used in calculating the interest cost. We assert that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum. At December 31, 2015, based on an interest rate of three-month LIBOR plus 4% related interest would be $6.4 million. At this time, no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $44.8 million as at December 31, 2015. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 23, 2016.

Name	Age	Position
Gary S. Guidry	60	President and Chief Executive Officer, Director
Ryan Ellson	40	Chief Financial Officer
Adrian Coral	42	President, Gran Tierra Energy Colombia
James Evans	50	Vice President, Corporate Services
David Hardy	61	Vice-President, Legal, Secretary and General Counsel
Alan Johnson	44	Vice President, Asset Management
Lawrence West	59	Vice President, Exploration

Gary Guidry, Chief Executive Officer and President. Mr. Guidry has been Gran Tierra's Chief Executive Officer and President since May 7, 2015. Mr. Guidry was the Chief Executive Officer of Onza Energy Inc. from January 2014, until May 2015. From July 2011 to July 2014, Mr. Guidry served as President and Chief Executive Officer of Caracal Energy Inc. Mr. Guidry also served as President and CEO of Orion Oil & Gas Corp. from October 2009 to July 2011, Tanganyika Oil Corp. from May 2005 to January 2009, and Calpine Natural Gas Trust from October 2003 to February 2005. As chief executive officer of these companies, Mr. Guidry was responsible for overseeing all aspects of the respective company's business. Mr. Guidry currently sits on the boards of Africa Oil Corp. (since April 2008) and Shamaran Petroleum Corp. (since February 2007), where he also serves as a member of each company's Audit Committee. From September 2010 to October 2011, Mr. Guidry also served on the Board of Zodiac Exploration Corp., and from October 2009 to March 2014, he served on the board of TransGlobe Energy Corp. Prior to these positions, Mr. Guidry served as Senior Vice President and subsequently President of Alberta Energy Company International, and President and General Manager of Canadian Occidental Petroleum's Nigerian operations. Mr. Guidry has directed exploration and production operations in Yemen, Syria and Egypt and has worked for oil and gas companies around the world in the U.S., Colombia, Ecuador, Venezuela, Argentina and Oman. Mr. Guidry is an Alberta-registered professional engineer (P. Eng.) and holds a B.Sc. in petroleum engineering from Texas A&M University.

Ryan Ellson, Chief Financial Officer. Mr. Ellson has been Gran Tierra's Chief Financial Officer since May 2015. Mr. Ellson has 15 years of experience in a broad range of international corporate finance and accounting roles. Mr. Ellson was CFO of Onza Energy Inc. from January 2015 to May 2015. From July 2014 until December 2014 Mr. Ellson was Head of Finance for Glencore E&P (Canada) and prior thereto Vice President, Finance at Caracal Energy, a London Stock Exchange listed company with operations in Chad, Africa from August 2011 until July 2014. Prior to Caracal, Mr. Ellson was Vice President of Finance at Sea Dragon Energy from April 2010 until August 2011. In these positions, Mr. Ellson oversaw financial and accounting functions, implemented and oversaw internal financial controls, secured a reserve based lending facility and was involved in multiple capital raises. Mr. Ellson has held management and executive positions with companies operating in Chad, Egypt, India and Canada. Mr. Ellson is a Chartered Accountant and holds a Bachelor of Commerce and a Master of Professional Accounting from the University of Saskatchewan.

Adrian Coral, President, Gran Tierra Energy Colombia. Mr. Coral joined Gran Tierra in August 2006 as an operations engineer in Gran Tierra Energy Colombia, Ltd., and served in that capacity until February 2007. Mr. Coral rejoined Gran Tierra in August 2008 as Operations Director of Gran Tierra Energy Colombia, Ltd. He served in that capacity until September 2011, when he was promoted to Production Manager of Gran Tierra Energy Colombia, Ltd. Mr. Coral was promoted to Senior Operations Manager of Gran Tierra Energy Colombia, Ltd. in April 2013. On August 1, 2014, Mr. Coral was promoted to President, Gran Tierra Energy Colombia. Mr. Coral has a total of 18 years of experience as an engineer or manager in the oil and gas industry. Mr. Coral graduated from the Universidad de América – Bogotá D.C. with a degree as a Petroleum Engineer and from the School of Business Management – Bogotá D.C with degree in Project Management.

James Evans, Vice President, Corporate Services. Mr. Evans has been Gran Tierra's Vice President, Corporate Services, since May 2015. Mr. Evans has over 20 years of experience including working the last 10 years in the international oil and gas industry. Most recently, Mr. Evans was the Head of Compliance & Corporate Services for Glencore E&P (Canada) from July 2014 to December 2014, and prior thereto Vice President of Compliance & Corporate Services at Caracal Energy from July

2011 to June 2014, in each case where he oversaw the execution of corporate strategy and goals, developed and implemented a robust corporate compliance program, and managed all aspects of IT, document control, security and administration. Mr. Evans also managed the recruitment, training and retention of staff in both Calgary and Chad. He oversaw the growth of Caracal Energy from seven employees to in excess of 400 as Caracal Energy exceeded 20,000 barrels of oil per day at the time of sale to Glencore. Prior to Caracal, Mr. Evans held senior management and executive positions at Orion Oil and Gas and Tanganyika Oil, with operating experience in Egypt, Syria and Canada. Mr. Evans is a Certified General Accountant and holds a Bachelor of Commerce degree from the University of Calgary.

David Hardy, Vice President, Legal, and Secretary and General Counsel. Mr. Hardy joined Gran Tierra as General Counsel, Vice President Legal and Secretary on March 1, 2010. He has more than 25 years' experience in the legal profession. Before joining Gran Tierra, he worked for Encana Corporation and for Encana Corporation's predecessor, Pan Canadian, from 2000 through 2009 where he held various positions, including: Vice President Divisional Legal Services, Integrated Oil and Canadian Plains Divisions; Vice President Regulatory Services, Corporate Relations Division; and Associate General Counsel, Offshore and International Division. For four of his eight years in the Offshore and International Division of Encana, Mr. Hardy led the Legal and Commercial Negotiations Group, where he was responsible for providing strategic legal, commercial and negotiation advice and support to the offshore and international business units. This included dealing with new venture activities and operational, joint venture and host government issues relating to projects in various countries, including Australia, Brazil, Chad, Libya, Oman, Qatar and Yemen. Prior to joining Encana, Mr. Hardy spent over 10 years in private practice and was a partner in a law firm in Calgary, Alberta. He holds a Juris Doctor Degree from the University of Calgary (converted from an LL.B Degree in 2011) and is a member of the Law Society of Alberta and the Association of International Petroleum Negotiators.

Alan Johnson, Vice President, Asset Management. Mr. Johnson has been Gran Tierra's Vice President, Asset Management, since May 2015. Mr. Johnson is a professional engineer with more than 20 years experience working internationally in the oil and gas industry. His experience includes varied technical, managerial and executive roles in drilling, production, reservoir, reserves, corporate planning and asset management. Most recently Mr. Johnson was Head of Asset Management for Glencore E&P (Canada) from April 2014 to April 2015, where he was responsible for all development activities in Chad and prior thereto Director of Asset Management at Caracal Energy from August 2011 to March 2014, where he was responsible for development activities in the Doba basin in Chad, Africa. Mr. Johnson was instrumental in developing oil and gas assets in remote areas of southern Chad, achieving first production in less than 18 months. Mr. Johnson started his E&P career with Shell International in the Dutch North Sea. He then held positions of increasing responsibility with Shell Canada, APF Energy, Rockyview Energy, Delphi Energy and BG Australia. Mr. Johnson graduated with a 1st Class B. Eng (Hons) from Heriot Watt University in Scotland. Mr. Johnson is a Chartered Engineer in the UK and a Professional Engineer in Alberta.

Lawrence West. Vice President, Exploration. Mr. West has been Gran Tierra's Vice President, Exploration, since May 2015. Mr. West has thirty-five years of experience as an executive, explorationist, and geologist. Most recently, Mr. West was Vice President, Exploration at Caracal Energy from July 2011 to June 2014. Mr. West built a multi-disciplinary team to assess resources and grow reserves in the interior rift basins within Chad and led a successful exploration program. During his tenure he successfully executed two large 2D/3D seismic shoots in remote frontier basins, on time and on budget. Prior to Caracal he has been involved in starting and growing several public and private companies, including Reserve Royalty Corp., Chariot Energy, Auriga Energy and Orion Oil and Gas. Lawrence worked at Alberta Energy Company (AEC), where he was on the team that merged with Conwest. He built and led the AEC East team to the Rocky Mountain USA basins. His career began with Imperial Oil working on prospect and reservoir characterization, in multi-disciplinary teams, and as a technical mentor to exploration teams. Lawrence has an Honours Bachelor of Science in Geology from McMaster University and an MBA, specializing in economics, from the University of Calgary.

PART II

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

Shares of our Common Stock trade on the NYSE MKT and on the Toronto Stock Exchange ("TSX") under the symbol “GTE”. In addition, the exchangeable shares in one of our subsidiaries, Gran Tierra Exchangeco, are listed on the TSX and are trading under the symbol “GTX”.

As of February 23, 2016, there were approximately: 35 holders of record of shares of our Common Stock and 287,129,518 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately four holders of record of 3,638,889 exchangeable shares which may be exchanged on a 1-for-1 basis into shares of our Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing sixteen holders of record of 4,903,177 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into shares of our Common Stock.

For the quarters indicated from January 1, 2014, through the end of the fourth quarter of 2015, the following table shows the high and low closing sale prices per share of our Common Stock as reported on the NYSE MKT.

	High	Low
Fourth Quarter 2015	$2.91	$2.01
Third Quarter 2015	$2.92	$1.91
Second Quarter 2015	$3.87	$2.72
First Quarter 2015	$3.93	$2.10
Fourth Quarter 2014	$5.43	$3.11
Third Quarter 2014	$8.04	$5.54
Second Quarter 2014	$8.12	$6.97
First Quarter 2014	$7.74	$6.82

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Issuer Purchases of Equity Securities

	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid per Share [2]	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs[3]
July 1-31, 2015	—	—	—	13,831,866
August 1-31, 2015	2,575,996	2.18	2,575,996	11,255,870
September 1-30, 2015	424,800	2.30	424,800	10,831,070
October 1-31, 2015	485,100	2.24	485,100	10,345,970
November 1-30, 2015	—	—	—	10,345,970
December 1-31, 2015	1,081,240	2.12	1,081,240	9,264,730
Total	4,567,136	2.19	4,567,136	9,264,730

(1) Based on settlement date.

(2) Exclusive of commissions paid to the broker to repurchase the common shares.

(3) On July 22, 2015, we announced that we intended to implement a share repurchase program or normal course issuer bid (the “2015 Program”) through the facilities of the Toronto Stock Exchange ("TSX"), the NYSE MKT and eligible alternative trading platforms in Canada and the United States. We received regulatory approval from the TSX to commence the 2015 Program on July 27, 2015. We are able to purchase at prevailing market prices up to 13,831,866 shares of Common Stock, representing 4.98% of our issued and outstanding shares of Common Stock as of July 21, 2015. The average daily trading volume of shares of Common Stock over the six calendar month period prior to July 28, 2015, was 946,386 meaning that we are entitled to purchase, on any trading day, up to 236,596 shares of Common Stock. Shares of Common Stock purchased pursuant to the 2015 Program will be canceled. The 2015 Program will expire on July 29, 2016, or earlier if the 4.98% share maximum is reached. The 2015 Program may be terminated by us at any time, subject to compliance with regulatory requirements. As such, there can be no assurance regarding the total number of shares that may be repurchased under the 2015 Program. Shareholders may obtain a copy of the Notice of Intention to Make A Normal Course Issuer Bid filed with the TSX detailing the 2015 Program free of

charge by writing or telephoning us at the address or phone number on the cover page of this Annual Report.

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, would be at the discretion of our Board of Directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility and, if the Company is not in default, it is required to obtain bank approval for dividend payments to shareholders outside of the credit facility group.

Performance Graph

The information in this Form 10-K appearing under the heading "Performance Graph" is being "furnished" pursuant to Item 2.01 (e) of Regulation S-K under the Securities Act and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01 (e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act and shall not be deemed incorporated by reference into any filing under the Securities Act of the Exchange Act except to the extent that we specifically request that it be treated as such.

Item 6. Selected Financial Data
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

Statement of Operations Data

	Year Ended December 31,				
	2015	2014	2013	2012	2011
Oil and natural gas sales	$276,011	$559,398	646,955	$503,467	$548,175
Operating expenses	75,565	89,753	91,223	65,562	51,690
Transportation	40,204	24,196	18,949	26,645	7,731
Depletion, depreciation and accretion	176,386	185,877	200,851	130,370	143,696
Asset impairment	323,918	265,126	2,000	20,200	42,000
G&A expenses	32,353	51,249	41,115	46,659	52,344
Severance expenses	8,990	—	—	—	—
Equity tax	3,769	—	—	—	8,271
Foreign exchange (gain) loss	(17,242)	(39,535)	(18,693)	28,727	(255)
Financial instruments loss (gain)	2,027	4,722	—	—	(1,354)
Other loss	—	—	4,400	—	—
Other gain	(502)	(2,000)	—	(9,336)	—
Gain on acquisition	—	—	—	—	(21,699)
	645,468	579,388	339,845	308,827	282,424
Interest income	1,369	2,856	2,174	1,709	1,124
(Loss) income from continuing operations before income taxes	(368,088)	(17,134)	309,284	196,349	266,875
Current income tax (expense) recovery	(15,383)	(92,865)	(157,126)	(69,453)	(134,018)
Deferred income tax recovery (expense)	115,442	(34,350)	28,865	(26,814)	18,728
	100,059	(127,215)	(128,261)	(96,267)	(115,290)
(Loss) income from continuing operations	(268,029)	(144,349)	181,023	100,082	151,585
Loss from discontinued operations, net of income taxes	—	(26,990)	(54,735)	(423)	(24,668)
Net income (loss)	$(268,029)	$(171,339)	126,288	$99,659	$126,917
INCOME (LOSS) PER SHARE BASIC					
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.94)	$(0.51)	$0.64	$0.35	$0.55
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	—	(0.09)	(0.19)	—	(0.09)
NET INCOME (LOSS) DILUTED	$(0.94)	$(0.60)	$0.45	$0.35	$0.46

(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.94)	$(0.51)	$0.63	$0.35	$0.54

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LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	—	(0.09)	(0.19)	—	(0.09)
NET INCOME (LOSS)	$(0.94)	$(0.60)	$0.44	$0.35	$0.45

Balance Sheet Data

	As at December 31,				
	2015	2014	2013	2012	2011
Cash and cash equivalents	$145,342	$331,848	$428,800	$212,624	$351,685
Working capital (including cash)[(1)]	160,449	239,312	244,764	220,288	210,071
Oil and gas properties	780,360	1,117,931	1,250,070	1,196,661	1,036,850
Deferred tax asset - long-term[(1)]	3,241	2,153	3,663	3,918	7,776
Total assets	1,146,118	1,714,050	1,904,550	1,732,875	1,626,780
Deferred tax liability - long-term[(1)]	34,592	176,364	178,275	225,532	186,799
Total long-term liabilities	70,485	213,039	209,270	250,396	207,633
Shareholders’ equity	1,001,642	1,276,685	1,429,908	1,291,431	1,174,318

[(1)] In accordance with generally accepted accounting principles in the United States of America ("GAAP") and as discussed further in Note 2, "Significant Accounting Policies" of our consolidated financial statements for the three years ended December 31, 2015, we retrospectively reclassified deferred tax assets and liabilities as long-term assets and liabilities in our consolidated financial statements.

On June 25, 2014, we sold our Argentina business unit to Madalena Energy Inc. ("Madalena") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares. In accordance with GAAP, we met the criteria to classify our Argentina business unit as discontinued operations in the second quarter of 2014. As such, the results of operations for our Argentina business unit are reflected as loss from discontinued operations, net of income taxes and discussed further in Note 3, "Discontinued Operations," of our consolidated financial statements for the three years ended December 31, 2015. Amounts for 2012 and 2011 have been reclassified to conform to this presentation. The reclassifications had no effect on net income or loss.

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

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

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements and Supplementary Data" as set out in Part II, Item 8 of this Annual Report on Form 10-K.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our principal business activity is in Colombia and we also have business activities in Peru and Brazil. For the year ended December 31, 2015, 97% (year ended December 31, 2014 - 95%; year ended December 31, 2013 - 96%) of our revenue and other income was generated in Colombia. We are headquartered in Calgary, Alberta, Canada.

During early 2015, largely as a result of the low commodity price environment and drilling results in Peru, we ceased all development expenditures in the Bretaña Field on Block 95 in Peru other than what was necessary to maintain tangible asset integrity and security. As a result, all probable and possible reserves associated with the field were reclassified as contingent resources.

On May 7, 2015, we entered into an agreement (the “Agreement”) with West Face SPV (Cayman) I L.P. (“West Face”) pursuant to which we settled a proxy contest. Pursuant to the terms of the Agreement, Gary Guidry was appointed as our

President and Chief Executive Officer. Mr. Guidry replaced Duncan Nightingale in that role, who was serving as interim Chief Executive Officer since February 2015 and, with the appointment of Mr. Guidry as Chief Executive Officer, was designated as Executive Vice President until February 19, 2016, when he ceased performing this role. Additionally, effective May 11, 2015, Ryan Ellson was appointed as Chief Financial Officer. In connection with our entry into the Agreement, the size of our Board of Directors was expanded, new directors were appointed to fill the newly created vacancies and certain existing directors agreed not to stand for re-election at the 2015 annual meeting of stockholders. In June 2015, our Board of Directors approved a new capital program focusing on development activities in Colombia.

As of December 31, 2015, we had estimated proved reserves NAR of 38.9 MMBOE, approximately 98% oil, of which 80% were proved developed reserves. Our primary source of liquidity is cash generated from our operations and cash on hand.

On January 13, 2016, we acquired all of the issued and outstanding shares of Petroamerica Oil Corp ("Petroamerica") for cash consideration of $70.6 million and the issuance of 13,656,719 shares of Gran Tierra common stock with a value of $25.8 million. On January 25, 2016, we acquired all of the issued and outstanding shares of PetroGranada Colombia Limited ("PGC") for a net purchase price of $19.0 million, after giving consideration to estimated net working capital of $18.7 million. In addition, we agreed to pay contingent consideration of $4.0 million if cumulative production from the Putumayo-7 Block plus gross proved plus probable reserves under the Putumayo-7 Block meet or exceed 8 MMbbl. Combined proved NAR oil and gas reserves of Petroamerica and PGC as at December 31, 2015, were 3.9 MMBOE.

Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand imbalance and many other market factors outside of our control. Oil prices started falling in July 2014 and fell dramatically during the period December 2014 to March 2015. Prices have remained low and volatile. During 2015, the average price realized for our oil was $41.56 per bbl (2014 - $83.22; 2013 - $92.31). Average Brent oil price for the year ended December 31, 2015, was $52.35 per bbl compared with $99.02 per bbl in 2014 and $108.64 in 2013. Average West Texas Intermediate ("WTI") oil price for the year ended December 31, 2015, was $48.78 per bbl compared with $93.00 per bbl in 2014 and $97.97 in 2013.

Highlights

	Year Ended December 31,				
	2015	% Change	2014	% Change	2013
Estimated Proved Oil and Gas Reserves, NAR, at December 31 (MMBOE)	38.9	5	37.0	(12)	42.1
Estimated Probable Oil and Gas Reserves, NAR, at December 31 (MMBOE)	15.7	16	13.5	(81)	69.8
Estimated Possible Oil and Gas Reserves, NAR, at December 31 (MMBOE)	12.6	(18)	15.4	(79)	72.0
Volumes (BOE)					
Working Interest Production Before Royalties	8,541,393	(7)	9,191,467	(2)	9,357,967
Royalties	(1,428,088)	(34)	(2,153,013)	(10)	(2,397,037)
Production NAR	7,113,305	1	7,038,454	1	6,960,930
Change in Inventory	(448,562)	62	(277,485)	(553)	61,217
Sales[(1)]	6,664,743	(1)	6,760,969	(4)	7,022,147
Average Daily Volumes (BOEPD)					
Working Interest Production Before Royalties	23,401	(7)	25,182	(2)	25,638
Royalties	(3,912)	(34)	(5,899)	(10)	(6,567)
Production NAR	19,489	1	19,283	1	19,071
Change in Inventory	(1,229)	62	(760)	(552)	168
Sales[(1)]	18,260	(1)	18,523	(4)	19,239
Oil and Gas Sales ($000s)	276,011	(51)	559,398	(14)	646,955
Operating Expenses ($000s)	(75,565)	(16)	(89,753)	(2)	(91,223)
Transportation expenses	(40,204)	66	(24,196)	28	(18,949)
Operating Netback ($000s)[(2)]	160,242	(64)	445,449	(17)	536,783
General and Administrative Expenses ("G&A")					
G&A Expenses Before Stock-Based Compensation, Gross	$66,251	(33)	$98,474	21	$81,498
Stock-Based Compensation	2,573	(58)	6,134	(18)	7,474
Capitalized G&A and Overhead Recoveries	(36,471)	(32)	(53,359)	11	(47,857)
	$32,353	(37)	$51,249	25	$41,115
EBITDA[(3)]	$132,216	(70)	$433,869	(15)	$512,135
Adjusted EBITDA[(3)]	$114,974	(71)	$394,334	(20)	$493,442
Net Income (Loss) ($000s)	$(268,029)	56	$(171,339)	(236)	$126,288
Funds Flow From Continuing Operations ($000s) [(4)]	$108,320	(66)	$319,614	(8)	$347,963
Net Capital Expenditures for Continuing Operations ($000s) [(5)]	$159,226	(62)	$416,232	41	$295,315

	As at December 31,				
	2015	% Change	2014	% Change	2013
Cash & Cash Equivalents ($000s)	$145,342	(56)	$331,848	(23)	$428,800
Working Capital (including cash & cash equivalents) ($000s)	$160,449	(33)	$239,312	(2)	$244,764

As previously discussed, all probable and possible reserves associated with the Bretaña Field on Block 95 in Peru were reclassified as contingent resources in a report with an effective date of January 31, 2015. These reserves are excluded from the table above. Estimated proved, probable and possible oil and gas reserves, NAR, as at December 31, 2013, included 4.4, 2.1 and 10.3 MMBOE, respectively, in Argentina.

With the exception of reserves and net income, the 2014 and 2013 amounts in the table above exclude amounts relating to discontinued operations. Oil and gas production NAR associated with discontinued operations was nil BOEPD for the year ended December 31, 2015 (2014 - 1,361 BOEPD; 2013 - 3,028 BOEPD). Argentina production for the December 31, 2014, was calculated to the date of sale of June 25, 2014.

(1) Sales volumes represent production NAR adjusted for inventory changes and losses.

Non-GAAP measures

Operating netback, EBITDA, adjusted EBITDA and funds flow from continuing operations are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Investors are cautioned that these measures should not be construed as alternatives to net income or loss or other measures of financial performance as determined in accordance with GAAP. Our method of calculating these measures may differ from other companies and, accordingly, may not be comparable to similar measures used by other companies.

(2) Operating netback as presented is oil and gas sales net of royalties and operating and transportation expenses. Management believes that netback is a useful supplemental measure for management and investors to analyze operating performance and provide an indication of the results generated by our principal business activities prior to the consideration of other income and expenses.

(3) EBITDA, as presented, is net income or loss adjusted for loss from discontinued operations, net of income taxes, depletion, depreciation and accretion ("DD&A") expenses, asset impairment and income tax recovery or expense. Adjusted EBITDA is EBITDA adjusted for foreign exchange gains. Management uses these financial measures to analyze performance and income or loss generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that these financial measures are also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income or loss to EBITDA and adjusted EBITDA is as follows:

	Year Ended December 31,		
EBITDA - Non-GAAP Measure ($000s)	2015	2014	2013
Net income (loss)	$(268,029)	$(171,339)	$126,288
Adjustments to reconcile net income (loss) to EBITDA			
Loss from discontinued operations, net of income taxes	—	26,990	54,735
DD&A expenses	176,386	185,877	200,851
Asset Impairment	323,918	265,126	2,000
Income tax (recovery) expense	(100,059)	127,215	128,261
EBITDA	$132,216	$433,869	$512,135
Foreign exchange gain	(17,242)	(39,535)	(18,693)

Adjusted EBITDA	$114,974	$394,334	$493,442

(4) Funds flow from continuing operations, as presented, is net income or loss adjusted for loss from discontinued operations, net of income taxes, DD&A expenses, asset impairment, deferred tax recovery or expense, non-cash stock-based compensation, financial instrument loss, unrealized foreign exchange gains, cash settlement of foreign currency derivatives, other gains and losses and equity tax. During the three months ended September 30, 2015, our new management changed our method of calculating funds flow from continuing operations to be more consistent with our peers. Funds flow from continuing operations is no longer net of cash settlement of asset retirement obligation. Additionally, foreign exchange losses on cash and cash equivalents have been excluded from funds flow. Comparative information has been reclassified to be calculated on a consistent basis. Management uses this financial measure to analyze performance and income or loss generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income or loss to funds flow from continuing operations is as follows:

Funds Flow From Continuing Operations - Non-GAAP Measure ($000s)	Year Ended December 31, 2015	2014	2013
Net income (loss)	$(268,029)	$(171,339)	$126,288
Adjustments to reconcile net income (loss) to funds flow from continuing operations			
Loss from discontinued operations, net of income taxes	—	26,990	54,735
DD&A expenses	176,386	185,877	200,851
Asset impairment	323,918	265,126	2,000
Deferred tax (recovery) expense	(115,442)	34,350	(28,865)
Non-cash stock-based compensation	2,091	5,451	8,002
Financial instruments loss	2,027	4,722	—
Unrealized foreign exchange gain	(8,380)	(30,941)	(16,103)
Cash settlement of foreign currency derivatives	(3,749)	4,661	—
Other loss	—	—	4,400
Other gain	(502)	(2,000)	—
Equity tax	—	(3,283)	(3,345)
Funds flow from continuing operations	$108,320	$319,614	$347,963

(5) In 2013, capital expenditures are net of proceeds of $54.0 million relating to termination of a farm-in agreement in Brazil; and $1.5 million relating to the sale of our working interest of a block in Colombia.

Business Environment Outlook

Our revenues are significantly affected by the continuing fluctuations in oil prices and pipeline disruptions in Colombia. Oil prices are volatile and unpredictable and are influenced by concerns about the quantity of world supply and demand, market competition between large suppliers to the market for market share, political influences, financial markets and the impact of the worldwide economy on oil supply and demand growth.

We believe that our current operations and 2016 capital expenditure program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including additional pipeline delivery restrictions in Colombia or continued downturn in oil and gas prices, we would consider financing our capital expenditure program with borrowings under our revolving credit facility, proceeds from the disposition of assets or capital markets transactions, or a combination thereof, or we would consider reducing our capital expenditure program. Given the current economic environment and unstable conditions in the Middle East, North Africa, and Eastern Europe and the current over supply of oil in world markets, the oil price environment is unpredictable and unstable. We are unable to determine the impact, if any, these events may have on oil prices and demand. The timing and execution of our capital expenditure program are also affected by the availability of services from third party oil field contractors and our ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities. Any delay may affect our ability to execute our capital expenditure program.

The credit markets, including the high yield bond market and other debt markets that provide capital to oil and gas companies have experienced adverse conditions. We have not been materially impacted by these conditions; however, continuing volatility in oil prices may continue to contribute to these adverse conditions, which could increase costs associated with renewing or issuing debt or affect our ability to access those markets.

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

For over 40 years, the Colombian government has been engaged in a conflict with two main Marxist guerrilla groups: the Revolutionary Armed Forces of Colombia ("FARC") and the National Liberation Army ("ELN"). Both of these groups have been designated as terrorist organizations by the United States and the European Union. Another threat comes from criminal gangs formed from the former members of the United Self-Defense Forces of Colombia militia, a paramilitary group that originally sprouted up to combat FARC and ELN, which the Colombian government successfully dissolved. We operate principally in the Putumayo Basin in Colombia. Pipelines have been primary targets because such pipelines cannot be adequately secured due to the sheer length of such pipelines and the remoteness of the areas in which the pipelines are laid. The CENIT S.A-operated Trans-Andean oil pipeline (the "OTA pipeline") which transports oil from the Putumayo region and which is one of our export routes, has been targeted by these guerrilla groups. In 2015, the OTA pipeline was shutdown for approximately 213 days, which included 117 days as a result of a landslide.

While peace talks continue between the Colombian government and the FARC, peace process negotiations between the government and FARC may not generate the intended outcome for both parties, though the Colombian government has stated that a resolution is expected to be reached during the first quarter of 2016. The impact of such a peace process is not determinable on our operations. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

Consolidated Results of Operations

	Year Ended December 31,				
	2015	% Change	2014	% Change	2013
(Thousands of U.S. Dollars)					
Oil and natural gas sales	$276,011	(51)	$559,398	(14)	$646,955
Operating expenses	75,565	(16)	89,753	(2)	91,223
Transportation expenses	40,204	66	24,196	28	18,949
DD&A expenses	176,386	(5)	185,877	(7)	200,851
Asset impairment	323,918	22	265,126	—	2,000
G&A expenses	32,353	(37)	51,249	25	41,115
Severance expenses	8,990	—	—	—	—
Equity tax	3,769	—	—	—	—
Foreign exchange gain	(17,242)	56	(39,535)	(111)	(18,693)
Financial instruments loss	2,027	(57)	4,722	—	—
Other loss	—	—	—	(100)	4,400
Other gain	(502)	75	(2,000)	—	—
	645,468	11	579,388	70	339,845
Interest income	1,369	(52)	2,856	31	2,174
(Loss) income from continuing operations before income taxes	(368,088)	(2,048)	(17,134)	(106)	309,284
Current income tax expense	(15,383)	(83)	(92,865)	(41)	(157,126)
Deferred income tax recovery (expense)	115,442	(436)	(34,350)	219	28,865
	100,059	(179)	(127,215)	(1)	(128,261)
(Loss) income from continuing operations	(268,029)	(86)	(144,349)	(180)	181,023
Loss from discontinued operations, net of income taxes	—	(100)	(26,990)	(51)	(54,735)
Net income (loss)	$(268,029)	(56)	$(171,339)	(236)	$126,288
Sales Volumes[(1)]					
Oil and NGL's, bbl	6,611,680	(1)	6,706,083	(4)	7,006,657
Natural gas, Mcf	318,379	(3)	329,312	254	92,942
Total sales volumes, BOE	6,664,743	(1)	6,760,968	(4)	7,022,147
Average Prices					
Oil and NGL's per bbl	$41.56	(50)	$83.22	(10)	$92.31
Natural gas per Mcf	$3.80	(16)	$4.52	24	$3.64

Consolidated Results of Operations per BOE Sales Volumes

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Oil and natural gas sales	$41.41	(50)	$82.74	(10)	$92.13
Operating expenses	11.34	(15)	13.28	2	12.99
Transportation expenses	6.03	68	3.58	33	2.70
DD&A expenses	26.47	(4)	27.49	(4)	28.60
Asset impairment	48.60	24	39.21	—	0.29
G&A expenses	4.85	(36)	7.58	29	5.86
Severance expenses	1.35	—	—	—	—
Equity tax	0.57	—	—	—	—
Foreign exchange gain	(2.59)	56	(5.85)	(120)	(2.66)
Financial instruments loss	0.30	(57)	0.70	—	—
Other loss	—	—	—	(100)	0.63
Other gain	(0.08)	73	(0.30)	—	—
	96.84	13	85.69	77	48.41
Interest income	0.21	(50)	0.42	35	0.31
(Loss) income from continuing operations before income taxes	(55.22)	(2,083)	(2.53)	(106)	44.03
Current income tax expense	(2.31)	(83)	(13.74)	(39)	(22.38)
Deferred income tax recovery (expense)	17.32	(441)	(5.08)	224	4.11
	15.01	(180)	(18.82)	(3)	(18.27)
(Loss) income from continuing operations	$(40.21)	(88)	$(21.35)	(183)	$25.76

With the exception of net income and loss from discontinued operations, the 2014 and 2013 amounts in the table above exclude amounts relating to discontinued operations. Oil and gas production NAR associated with discontinued operations was nil BOEPD for the year ended December 31, 2015 (2014 - 1,361 BOEPD; 2013 - 3,028 BOEPD). Argentina production for the year ended December 31, 2014, was calculated to the date of sale of June 25, 2014.

(1) Sales volumes represent production NAR adjusted for inventory changes and losses.

Consolidated Results of Continuing Operations for the Year Ended December 31, 2015, Compared with the Results for the Years Ended December 31, 2014 and 2013

Oil and Gas Production and Sales Volumes, BOEPD

	Year Ended December 31,		
Average Daily Volumes (BOEPD) - Colombia	2015	2014	2013
Working Interest Production Before Royalties	22,794	24,128	24,811
Royalties	(3,822)	(5,749)	(6,460)
Production NAR	18,972	18,379	18,351
(Increase) Decrease in Inventory	(1,231)	(760)	233
Sales	17,741	17,619	18,584

	Year Ended December 31,		
Average Daily Volumes (BOEPD) - Brazil	2015	2014	2013
Working Interest Production Before Royalties	607	1,054	827
Royalties	(90)	(150)	(107)
Production NAR	517	904	720
(Increase) Decrease in Inventory	2	—	(65)
Sales	519	904	655

	Year Ended December 31,		
Average Daily Volumes (BOEPD) - Total	2015	2014	2013
Working Interest Production Before Royalties	23,401	25,182	25,638
Royalties	(3,912)	(5,899)	(6,567)
Production NAR	19,489	19,283	19,071
(Increase) Decrease in Inventory	(1,229)	(760)	168
Sales	18,260	18,523	19,239

Oil and gas production NAR for the year ended December 31, 2015, increased by 1% to 19,489 BOEPD compared with 19,283 BOEPD in 2014.

In 2015 in Colombia, production from new wells in the Moqueta Field in the Chaza Block and increased production from the Jilguero Field in the Garibay Block, as a result of the unitization of that field and new wells coming on stream, was offset by the impact of normal field production declines in the Costayaco Field in the Chaza Block and the Juanambu Field in the Guayuyaco Block. Production during the year ended December 31, 2015, reflected approximately 213 days of OTA pipeline disruptions in Colombia compared with 180 days in 2014. Despite the OTA pipeline being down for 213 days we did not have to shut in any production in 2015 due to the different routes available to transport our crude oil.

In Brazil, our operations in the Tiê Field were suspended by the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") from March 11, 2015, to May 15, 2015, due to alleged non-compliance with certain requirements regarding the health and safety management system identified during a safety and operational audit conducted by the ANP in early 2015. Clearance to resume production was received on May 15, 2015. However, during the second half of 2015, our production in Brazil was limited by a temporary capacity reduction at a third party's shipping facility due to an integrity issue with one of their oil receiving tanks. The operator of the facility has advised that it expects to have this tank repaired and operational by the end of the first quarter of 2016.

Oil and gas production NAR for the year ended December 31, 2014, increased by 1% to 19,283 BOEPD compared with 19,071 BOEPD in 2013. In 2014 in Colombia, production from new wells in the Moqueta Field in the Chaza Block and a new well in the Llanos-22 Block were partially offset by the impact of well downtime for workovers and a water cut increase in the Costayaco Field in the Chaza Block. Production during the year ended December 31, 2014, reflected approximately 180 days of OTA pipeline disruptions in Colombia compared with 229 days in 2013.

Oil and gas sales volumes for the year ended December 31, 2015, decreased by 1% to 18,260 BOEPD compared with 18,523 BOEPD in 2014. During the year ended December 31, 2015, an oil inventory increase accounted for 0.4 MMbbl, or 1,229 bopd, of reduced sales compared with an oil inventory increase in 2014 which accounted for 0.3 MMbbl, or 760 bopd, reduced sales. Oil inventory changes are primarily in Colombia.

Oil and gas sales volumes for the year ended December 31, 2014, decreased by 4% to 18,523 BOEPD compared with 19,239 BOEPD in 2013. During the year ended December 31, 2014, an oil inventory increase in 2014 accounted for 0.3 MMbbl, or 760 bopd, of reduced sales compared with an oil inventory decrease in 2013 which accounted for 0.1 MMbbl, or 168 bopd, of increased sales.

Operating Netbacks

Colombia	Year Ended December 31,		
(Thousands of U.S. Dollars)	2015	2014	2013
Oil and Gas Sales	$269,035	$532,196	$624,410
Transportation Expenses	(40,083)	(23,704)	(18,522)
	228,952	508,492	605,888
Operating Expenses	(69,323)	(83,397)	(84,339)
Operating Netback(1)	$159,629	$425,095	$521,549
(U.S. Dollars per BOE)			
Oil and Gas Sales	$41.55	$82.76	$92.05
Transportation Expenses	(6.19)	(3.69)	(2.73)
	35.36	79.07	89.32
Operating Expenses	(10.71)	(12.97)	(12.43)
Operating Netback(1)	$24.65	$66.10	$76.89

Brazil	Year Ended December 31,		
(Thousands of U.S. Dollars)	2015	2014	2013
Oil and Gas Sales	$6,976	$27,202	$22,545
Transportation Expenses	(121)	(492)	(427)
	6,855	26,710	22,118
Operating Expenses	(6,242)	(6,356)	(6,884)
Operating Netback(1)	$613	$20,354	$15,234
(U.S. Dollars per BOE)			
Oil and Gas Sales	$36.84	$82.42	$94.31
Transportation Expenses	(0.64)	(1.49)	(1.79)
	36.20	80.93	92.52
Operating Expenses	(32.97)	(19.26)	(28.80)
Operating Netback(1)	$3.23	$61.67	$63.72

Total	Year Ended December 31,		
(Thousands of U.S. Dollars)	2015	2014	2013
Oil and Gas Sales	$276,011	$559,398	$646,955
Transportation Expenses	(40,204)	(24,196)	(18,949)
	235,807	535,202	628,006
Operating Expenses	(75,565)	(89,753)	(91,223)
Operating Netback(1)	$160,242	$445,449	$536,783
(U.S. Dollars per BOE)			
Oil and Gas Sales	$41.41	$82.74	$92.13
Transportation Expenses	(6.03)	(3.58)	(2.70)
	35.38	79.16	89.43
Operating Expenses	(11.34)	(13.28)	(12.99)
Operating Netback(1)	$24.04	$65.88	$76.44

U.S. Dollars Per BOE			
Brent	$52.35	$99.02	$108.64
WTI	$48.78	$93.00	$97.97

(1) Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to non-GAAP measures disclosure above regarding this measure.

Oil and gas sales for the year ended December 31, 2015, decreased to $276.0 million from $559.4 million in 2014 primarily as a result of the effect of decreased realized prices. Average realized prices decreased by 50% to $41.41 per BOE for the year ended December 31, 2015, from $82.74 per BOE for 2014 primarily due to lower benchmark oil prices. Average Brent oil prices for the year ended December 31, 2015, were $52.35 per bbl compared with $99.02 per bbl in 2014. WTI oil prices for the year ended December 31, 2015, were $48.78 per bbl compared with $93.00 per bbl in 2014.

During periods of OTA pipeline disruptions we have multiple transportation alternatives. Each transportation route has varying effects on realized prices and transportation costs. During the year ended December 31, 2015, 62% of our oil and gas volumes sold in Colombia were through alternative transportation routes alternatives compared with 52% in 2014.

Oil and gas sales for the year ended December 31, 2014, decreased to $559.4 million from $647.0 million in 2013 as a result of the combined effect of decreased sales and realized prices. Average realized prices decreased by 10% to $82.74 per BOE for the year ended December 31, 2014, from $92.13 per BOE for 2013. Average Brent oil prices for the year ended December 31, 2014, were $99.02 per bbl compared with $108.64 per bbl in 2013. WTI oil prices for the year ended December 31, 2014, were $93.00 per bbl compared with $97.97 per bbl in 2013. Additionally, beginning July 1, 2014, the port operations fee component of the OTA pipeline pricing structure increased by $2.94 per bbl resulting in a reduction of realized oil prices by this amount on sales delivered through the OTA pipeline. During the year ended December 31, 2014, 52% of our oil and gas volumes sold in Colombia were through alternative transportation routes alternatives compared with 64% in 2013.

Transportation expenses for the year ended December 31, 2015, were $40.2 million, or $6.03 per BOE, compared with $24.2 million, or $3.58 per BOE, in 2014. On a per BOE basis, transportation expenses increased by 68%. The increase in transportation expenses per BOE was primarily due to the alternative transportation routes used during periods of OTA pipeline disruptions. During 2015, we used new alternative transportation routes which carried higher transportation costs, but higher realized prices compared with other customers.

Transportation expenses for the year ended December 31, 2014, were $24.2 million, or $3.58 per BOE, compared with $18.9 million, or $2.70 per BOE, in 2013. On a per BOE basis, transportation expenses increased by 33%. The increase in transportation expenses per BOE was primarily due to higher transportation costs associated with higher sales using the OTA pipeline which carried higher transportation costs instead of the realized price reductions that we incurred with some alternative customers in 2013.

Operating expenses for the year ended December 31, 2015, were $75.6 million, or $11.34 per BOE, compared with $89.8 million, or $13.28 per BOE in 2014. On a per BOE basis, operating expenses decreased by 15%. The decrease in operating expenses per BOE in 2015 was primarily due to Colombian operating cost savings and the effect of the strengthening of the U.S. dollar against local currencies in South America. In Brazil, in the year ended December 31, 2015, we incurred $1.7 million, or $8.98 per bbl based on volumes sold in Brazil, of one-time penalties relating to alleged non-compliance with certain requirements regarding the health and safety management system, identified during a safety and operational audit conducted by the ANP in early 2015.

Operating expenses for the year ended December 31, 2014, were $89.8 million, or $13.28 per BOE, compared with $91.2 million, or $12.99 per BOE, in 2013. Operating expenses per BOE increased in 2014 primarily due to increased workover expenses.

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DD&A Expenses

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, U.S. Dollars Per BOE	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, U.S. Dollars Per BOE
Colombia	$167,701	$25.90	$174,063	$27.07
Brazil	6,183	32.66	9,932	30.09
Peru	789	—	690	—
Corporate	1,713	—	1,192	—
	$176,386	$26.47	$185,877	$27.49

	Year Ended December 31, 2013	
	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, U.S. Dollars Per BOE
Colombia	$184,697	$27.23
Brazil	14,761	61.75
Peru	362	—
Corporate	1,031	—
	$200,851	$28.60

DD&A expenses for the year ended December 31, 2015, decreased to $176.4 million from $185.9 million in 2014. On a per BOE basis, the depletion rate decreased by 4% to $26.47 from $27.49. On a per BOE basis, the decrease was due to lower costs in the depletable base and increased proved reserves at year end.

DD&A expenses for the year ended December 31, 2014, decreased to $185.9 million from $200.9 million in 2013. On a per BOE basis, the depletion rate decreased by 4% to $27.49 from $28.60. Increased proved reserves, were only partially offset by increased costs in the depletable base.

Asset Impairment

We follow the full cost method of accounting for our oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated “ceiling”. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year and it should not be assumed that estimates of future net revenues represent the fair market value of our reserves. We used an average Brent price of $54.08 per bbl for the purposes of the December 31, 2015, ceiling test calculations.

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2015	2014	2013
Impairment of oil and gas properties			
Colombia	$232,436	$—	$—
Brazil	46,933	—	2,000
Peru	41,916	265,126	—

	321,285	265,126	2,000
Impairment of inventory	2,633	—	—
	$323,918	$265,126	$2,000

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In the year ended December 31, 2015, ceiling test impairment losses in our Colombia and Brazil cost centers and inventory impairment losses were primarily due to lower oil prices. The ceiling test impairment loss in our Brazil cost center was recognized during the first three quarters of 2015. As a result of a technical evaluation of the Brazil cost center reserves completed during the fourth quarter of 2015, an upward technical revision in proved reserves resulted in no ceiling test impairment loss during that quarter. Impairment losses in our Peru cost center related to costs incurred on Block 95.

In the year ended December 31, 2014, impairment losses in our Peru cost center related to costs incurred on Block 95, and in the year ended December 31, 2013, ceiling test impairment losses in our Brazil cost center related to lower realized prices and an increase in operating costs.

G&A Expenses

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2015	2014	2013
G&A Expenses Before Stock-Based Compensation, Gross	$66,251	$98,474	$81,498
Stock-Based Compensation	2,573	6,134	7,474
Capitalized G&A and Overhead Recoveries	(36,471)	(53,359)	(47,857)
	$32,353	$51,249	$41,115
U.S. Dollars Per BOE			
G&A Expenses Before Stock-Based Compensation, Gross	$9.94	$14.57	$11.61
Stock-Based Compensation	0.39	0.91	1.06
Capitalized G&A and Overhead Recoveries	(5.47)	(7.90)	(6.82)
	$4.86	$7.58	$5.85

G&A expenses for the year ended December 31, 2015, of $32.4 million decreased by 37% from $51.2 million in 2014. These decreases were mainly due to reductions in the number of our employees as part of our cost saving measures, a focus on reductions of our other G&A expenses and the effect of the strengthening of the U.S. dollar against local currencies in South America and Canada, which resulted in savings for costs denominated in local currency. Additionally, G&A expenses in the year ended December 31, 2015, were net of a credit of $2.6 million relating to the reversal of stock-based compensation expense for unvested options and RSUs associated with terminated employees. These G&A expense reductions were partially offset by lower allocations to capital projects due to lower capital activity and deferred financing fees expensed as a result of the cancellation of our previous credit facility. G&A expenses per BOE in the year ended December 31, 2015, of $4.85 were 36% lower compared with $7.58 in 2014 for the same reasons, partially offset by lower sales.

G&A expenses for the year ended December 31, 2014, of $51.2 million increased by 25% from $41.1 million in 2013. The increase was primarily due to higher salary and consulting expenses associated with increased activity for expanded operations in Peru in 2014.

Severance Expenses

For the year ended December 31, 2015, severance expenses were $9.0 million compared with nil in 2014 and 2013. During the year ended December 31, 2015, we reduced the number of our employees and contractors.

Equity Tax Expense

For the year ended December 31, 2015, equity tax expense of $3.8 million represented a Colombian tax which was calculated based on our Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. The legal obligation for each year's equity tax liability arises on January 1 of each year, therefore, we recognized the 2015 annual equity tax amount in our consolidated statement of operations during the first quarter of 2015.

Foreign Exchange Gains

For the years ended December, 2015, 2014 and 2013, we had foreign exchange gains of $17.2 million, $39.5 million and $18.7 million, respectively. Under U.S. GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation was the main source of the foreign exchange gains. The following table presents the change in the Colombian peso against the U.S. dollar for the three years ended December 31, 2015:

	Year Ended December 31,		
	2015	2014	2013
Change in the Colombian peso against the U.S. dollar	weakened by 32%	weakened by 24%	weakened by 9%

Financial Instrument Gains and Losses

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2015	2014	2013
Trading securities loss	$ 1,335	$ 6,326	$ —
Foreign currency derivatives loss (gain)	692	(1,604)	—
	$ 2,027	$ 4,722	$ —

Trading securities losses related to unrealized losses on the Madalena Energy Inc. ("Madalena") shares we received in connection with the sale of our Argentina business unit in June 2014.

Foreign currency derivative gains and losses related to our Colombian peso non-deliverable forward contracts. We purchased these contracts for purposes of fixing the exchange rate at which we would purchase or sell Colombian pesos to settle our income tax installments and payments. At December 30, 2015, we did not have any open foreign currency derivative positions.

Other Gains and Losses

Other gains and losses in the three years ended December 31, 2015, related to a contingent loss accrued in connection with a legal dispute. In 2013, we received an adverse legal judgment and the amount awarded in the legal judgment was denominated in bbl of oil. We filed an appeal against the judgment. Other gains in the year ended December 31, 2014, related to a reduction in the value of this contingent loss due to lower oil prices. During the three months ended December 31, 2015, we received an adverse legal judgment from the appeal court. We paid $1.9 million, the amount awarded by the appeal court, during the fourth quarter of 2015 and a gain was recognized as a result of a reduction in the in the value of the previously recognized contingent loss.

Income Tax Expense and Recovery

Income tax recovery was $100.1 million for the year ended December 31, 2015 ($15.4 million current income tax expense and $115.4 million deferred income tax recovery), compared with income tax expense of $127.2 million in 2014 ($92.9 million current income tax expense and $34.4 million deferred income tax expense). Current income tax expense was lower in 2015 as a result of lower taxable income in Colombia. The deferred tax recovery for the year ended December 31, 2015, included $91.7 million associated with the ceiling test impairment loss in Colombia. In 2014, deferred income tax recovery associated with impairment losses in Peru was offset by a full valuation allowance

Our effective tax rate was 27% for the year ended December 31, 2015. In the year ended December 31, 2014, we had income tax expense despite having losses from continuing operations. In 2014, our loss before income taxes was primarily due to impairment losses in Peru which were fully offset by an increase in the valuation allowance. The increase in the effective tax rate for the year ended December 31, 2015, compared with 2014 was primarily due to a smaller increase in the valuation allowance as a result of lower impairment losses in Peru where there is a full valuation allowance and an increase in foreign currency translation adjustments. Additionally, our income tax expense in 2014 reflected the impact of future income tax rate changes in Colombia on our deferred tax liability. In 2014, tax legislation was enacted in Colombia which increased the 2015 to 2018 tax rates resulting in an increase of the Colombian deferred tax liability of approximately $31.0 million.

For the year ended December 31, 2015, the difference between the effective tax rate of 27% and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance, non-deductible third party royalty in Colombia and other local taxes, partially offset by the impact of foreign taxes, foreign currency translation adjustments and other permanent differences.

Income tax expense was $127.2 million for the year ended December 31, 2014, compared with $128.3 million in 2013. The decrease was primarily due to lower taxable income in Colombia and lower taxes in Brazil, partially offset by the impact of future tax rate changes on the Colombian deferred tax liability, as discussed above. In 2013 in Brazil, a net payment of $54.0 million from a third party in connection with the termination of a farm-in agreement resulted in a current tax expense of approximately $10.4 million.

In the year ended December 31, 2014, we had income tax expense despite having loss from continuing operations, compared with an effective tax rate of 41% in 2013. For the year ended December 31, 2014, the difference between the effective tax rate and the 35% U.S. statutory rate was primarily a result of a loss before income taxes caused by the 2014 impairment loss in Peru which was fully offset by an increase in the valuation allowance. Other factors that affected the effective tax rate in 2014 were the change in the Colombian future tax rate, a non-deductible third party royalty in Colombia, the impact of other local taxes, and stock-based compensation, partially offset by foreign currency translation adjustments and other permanent differences.

The variance from the 35% U.S. statutory rate for the year ended December 31, 2013, was primarily attributable to an increase in the valuation allowance, a non-deductible third party royalty in Colombia, the impact of local taxes, and stock-based compensation, partially offset by other permanent differences, foreign currency translation adjustments and the foreign tax rate differential.

Loss from Discontinued Operations

On June 25, 2014, we sold our Argentina business unit to Madalena for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares. In accordance with generally accepted accounting principles in the United States of America ("GAAP"), we met the criteria to classify our Argentina business unit as discontinued operations in the second quarter of 2014. As such, the results of operations for our Argentina business unit are reflected as loss from discontinued operations, net of income taxes and discussed further in Note 3, "Discontinued Operations," of our consolidated financial statements for the three years ended December 31, 2015.

Funds Flow From Continuing Operations

For the year ended December 31, 2015, funds flow from continuing operations decreased by 66% from $319.6 million to $108.3 million primarily due to decreased oil and natural gas sales, higher transportation, severance and equity tax expenses and cash outflow on settlement of foreign currency derivatives, partially offset by decreased operating, G&A and income tax expenses and higher realized foreign exchange gains.

For the year ended December 31, 2014, funds flow from continuing operations decreased by 8% from $348.0 million to $319.6 million primarily due to decreased oil and natural gas sales, increased transportation and G&A expenses and lower realized foreign exchange gains, partially offset by decreased operating and income tax expenses and cash inflows on settlement of foreign currency derivatives.

2016 Capital Program

In January 2016, we announced our 2016 capital budget. Our base 2016 capital program of $107 million consists of: $76 million for Colombia; $8 million for Brazil; $6 million for Peru; and $17 million for other.

In Colombia, our base 2016 capital program includes two water injector wells in the Costayaco Field and three development wells in the Moqueta Field, both on the Chaza Block (100% WI, operated), two exploration wells and a development well in the Putumayo-7 Block (subject to regulatory approval, 100% WI, operated) and an exploration well on the Llanos-10 Block (50% WI, non-operated) with the costs being carried by a third party. Facilities work is also planned for the Chaza Block.

In Peru, the 2016 capital program includes only those activities required for retention of lands and security of assets. In Brazil, the capital program includes minimal activity to implement water injection for reservoir pressure maintenance, and to preserve current production levels. In both Peru and Brazil, operations have been scaled back significantly, with the aim of allowing time to explore and execute on options to maximize shareholder value.

In addition to our 2016 base capital budget, we have a discretionary capital budget of $61 million that we may utilize during 2016 in the event of an increase in commodity prices. If deployed, we expect that our discretionary capital budget would target six exploration wells, five development wells and seismic activities in Colombia.

We expect to finance our 2016 capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the year ended December 31, 2015, were $87.7 million, including drilling of $60.5 million, facilities of $13.6 million, seismic expenditures of $6.2 million and $7.4 million of other expenditures.

The significant elements of our 2015 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Costayaco-25D and Costayaco-26D development wells in the Costayaco Field, and the Moqueta-17 and Moqueta-21D development wells in the Moqueta Field, as oil producers. The Moqueta-19i well was completed as a water injector as planned. We commenced drilling the Costayaco-24D and Costayaco-27i development well and started pre-drilling activities for the Moqueta-20, 22 and 23 development wells. We also drilled the Moqueta-18i development well and encountered mechanical difficulties. The well is currently suspended.

- On the Garibay Block (50% WI, non-operated) and Tiple Block (owned by two other parties), the unitization of the Jilguero Field was completed and we became a 38.5% WI owner in the newly unitized field. Together with our partners, we drilled and completed three development wells, Jilguero Sur-2, Jilguero-3 and Jilguero-4 as oil producing wells.

- We completed the acquisition of 2-D seismic on the Cauca-7 (100% WI, operated), Sinu-1 (60% WI, operated) and Sinu-3 (51% WI, operated) Blocks and continued activities in preparation for the acquisition of 2-D seismic on the Putumayo-10 Block (100% WI, operated). We also commenced environmental impact assessments ("EIA"s) for future drilling on the Sinu-3 Block.

- We also continued facilities work at the Costayaco and Moqueta Fields on the Chaza Block, and on the Garibay Block.

Outlook - Colombia

Our base 2016 capital program in Colombia is $76 million and includes two water injector wells in the Costayaco Field and three development wells in the Moqueta Field, both on the Chaza Block (100% WI, operated), two exploration wells and a development well in the Putumayo-7 Block (subject to regulatory approval, 100% WI, operated) and an exploration well in the Llanos-10 Block (50% WI, non-operated). The Llanos-10 exploration well is being drilled by an industry partner and our share of the cost is expected to be less than $0.5 million. Facilities work is also planned for the Chaza Block.

Capital Program – Brazil

Capital expenditures in our Brazilian segment during the year ended December 31, 2015, were $20.0 million, including drilling of $0.8 million, facilities of $5.6 million, seismic of $10.1 million and $3.5 million of other expenditures.

Our 2015 capital program in Brazil included:

- On Blocks REC-T-86, Block REC-T-117 and Block REC-T-118 (100% WI, operated)), we completed the acquisition, processing and interpretation of 3-D seismic.

- On Block REC-T-155 (100% WI, operated), we initiated construction of an infield gas pipeline between the Tiê facilities and 3-GTE-03-BA.

Outlook – Brazil

Our base 2016 capital program in Brazil is $8 million and includes minimal activity to implement water injection for reservoir pressure maintenance, and to preserve current production levels.

Capital Program – Peru

Capital expenditures in our Peruvian segment for the year ended December 31, 2015, were $50.4 million. Capital expenditures in 2015 included $39.4 million on Block 95 and $11.0 million on our other blocks in Peru, and consisted of drilling of $21.3 million, seismic expenditures of $5.4 million, facilities expenditures of $16.6 million and other expenditures of $7.1 million.

The significant elements of our 2015 capital program in Peru were:

- On Block 95 (100% WI, operated), we completed drilling operations in the Bretaña Sur 95-3-4-1X appraisal well on the L4 lobe in the Bretaña Field, which satisfied our work obligation for the fifth exploration period. We encountered approximately six feet of oil pay above the oil-water contact in the Vivian Sandstone Reservoir. This oil column was less than what we had estimated prior to drilling. As previously discussed, in February 2015, we ceased all further development expenditures in the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security. Prior to the decision to cease further development expenditures in the Bretaña Field, we continued construction of the long-term test facilities, continued the FEED study for full field development and completed a workover on the water disposal well Bretaña Norte 95-2-1XD ST on this field.

- On Blocks 107 and 133 (100% WI, operated), we continued the environmental permitting process. On Block 107, we completed the acquisition, interpretation and processing of 2-D seismic and commenced planning activities for the Osheki-1 exploration well and the refurbishment of the base camp and well location. Both of these planning activities were suspended at the end of February 2015.

Outlook - Peru

Our base 2016 capital program in Peru is $6 million and includes only those activities required for retention of lands and security of assets.

Liquidity and Capital Resources

At December 31, 2015, we had cash and cash equivalents of $145.3 million compared with $331.8 million at December 31, 2014, and $428.8 million at December 31, 2013.

We believe that our cash resources, including cash on hand and cash generated from operations, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2016, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank in interest earning current accounts or are invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At December 31, 2015, 92% of our cash and cash equivalents were held by subsidiaries and partnerships outside of Canada and the United States. This cash was generally not available to fund domestic or head office operations unless funds were repatriated. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

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

We have a credit facility with a syndicate of lenders. Availability under the credit facility is determined by a proven reserves-based borrowing base, and remains subject to the satisfaction of conditions precedent set forth in the credit agreement. Loans under the credit agreement will mature on September 18, 2018. The initial borrowing base is $200 million and the borrowing base will be re-determined semi-annually based on reserve evaluation reports, subject to a maximum of $500 million. The borrowing base for the credit facility is supported by the present value of the petroleum reserves of two of our subsidiaries with operating branches in Colombia. The credit agreement includes a letter of credit sub-limit of up to $100 million. Amounts drawn down under the facility bear interest, at our option, at the USD LIBOR rate plus a margin ranging from 2.00% and

3.00% per annum, or an alternate base rate plus a margin ranging from 1.00% per annum to 2.00% per annum, in each case based on the borrowing base utilization percentage. Undrawn amounts under the credit facility bear interest at 0.75% per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure. Under the terms of the credit facility, we are required to maintain compliance with certain financial and operating covenants which include: the maintenance of a ratio of debt, including letters of credit, to earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses ("EBITDAX") not to exceed 4.00 to 1.0; the maintenance of a ratio of senior secured obligations to EBITDAX not to exceed 3.00 to 1.00; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5 to 1.0. As at December 31, 2015, we were in compliance with all financial and operating covenants in our credit agreement. No amounts have been drawn on this facility. This credit facility was entered into and became effective on September 18, 2015, and replaced our previous credit facility which was canceled on this date. Under the terms of the credit facility, we cannot pay any dividends to our shareholders if we are in default under the facility and, if we are not in default, we are required to obtain bank approval for dividend payments to shareholders outside of the credit facility group.

Cash Flows

During the year ended December 31, 2015, our cash and cash equivalents decreased by $186.5 million as a result of cash used in investing activities of $233.0 million, cash used in financing activities of $9.3 million and foreign exchange loss on cash and cash equivalents of $6.5 million, partially offset by cash provided by operating activities of $62.3 million.

During the year ended December 31, 2014, our cash and cash equivalents decreased by $97.0 million as a result of cash used in investing activities of $316.8 million (including $30.4 million cash used in investing activities of discontinued operations) and foreign exchange loss on cash and cash equivalents of $7.5 million, partially offset by cash provided by operating activities of $216.2 million (including $4.8 million of cash used in operating activities of discontinued operations) and cash provided by financing activities of $11.1 million.

During the year ended December 31, 2013, our cash and cash equivalents increased by $216.2 million as a result of cash provided by operating activities of $523.6 million (including $31.1 million of cash provided by operating activities of discontinued operations) and cash provided by financing activities of $3.8 million, partially offset by cash used in investing activities of $308.5 million (including $18.8 million cash used in investing activities of discontinued operations) and foreign exchange loss on cash and cash equivalents of $2.7 million.

Cash provided by operating activities in the year ended December 31, 2015, was primarily affected by decreased oil and natural gas sales, higher transportation, severance and equity tax expenses, cash outflow on settlement of foreign currency derivatives, partially offset by decreased operating, and G&A and income tax expenses and higher realized foreign exchange gains. The main changes in assets and liabilities from operating activities were as follows: accounts receivable decreased by $44.4 million primarily due to lower oil and gas sales; inventory increased by $1.6 million primarily due to higher inventory volumes as a result of OTA pipeline disruptions, partially offset by lower inventory costs per bbl; accounts payable and accrued liabilities decreased by $34.5 million due to the timing of payments for drilling activity; and net taxes payable decreased by $48.3 million primarily due to lower current income taxes for 2015 in Colombia.

Cash provided by operating activities of continuing operations in the year ended December 31, 2014, was primarily affected by
decreased oil and natural gas sales, increased transportation and G&A expenses and lower realized foreign exchange gain, partially offset by decreased operating and income tax expenses and cash inflows on settlement of foreign currency derivatives. The main changes in assets and liabilities from operating activities were as follows: accounts

receivable increased by $34.5 million primarily due to an increase in the number of days of sales outstanding in Colombia as a result of a higher portion of sales being to Ecopetrol which has longer payment terms than our other significant customers; inventory increased by $2.9 million primarily due to the timing of recognition of oil sales to a customer in Colombia where the sale is not recognized until the customer exports oil; accounts payable and accrued liabilities increased by $0.6 million due to the timing of payments for drilling activity and higher accruals for trucking costs; and net taxes payable decreased by $61.1 million primarily due to payment of 2013 income taxes in Colombia and lower current income taxes for 2014 in Colombia.

Cash provided by operating activities of continuing operations in the year ended December 31, 2013, was primarily affected by increased oil and natural gas sales, decreased G&A expenses, decreased realized foreign exchange losses and a $146.6 million change in assets and liabilities from operating activities. These increases were partially offset by increased operating and income tax expenses. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets decreased by $59.0 million primarily due to a reduction in the number of days of sales outstanding in Colombia which resulted from a larger portion of sales in 2013 being to a customer with more favorable payment terms; inventory decreased by $14.2 million primarily due to the reduced oil inventory in the OTA pipeline and associated Ecopetrol operated facilities in the Putumayo Basin and reduced oil inventory related to the timing of recognition of oil sales to a short-term customer in Colombia; accounts payable and accrued liabilities decreased by $8.8 million due to the timing of payments for drilling activity; and net taxes payable increased by $84.7 million due to increased taxable income in Colombia and the reimbursement of value added tax receivable in Colombia.

Cash outflows from investing activities in the year ended December 31, 2015, included capital expenditures of $156.6 million and $76.8 million of net cash outflows related to changes in assets and liabilities associated with investing activities, partially offset by a decrease in restricted cash of $0.5 million. Cash outflows from investing activities of continuing operations in the year ended year ended December 31, 2014, included capital expenditures of $391.5 million and an increase in restricted cash of $0.1 million, partially offset by $44.5 million of net cash inflows related to changes in assets and liabilities associated with investing activities. Cash outflows from investing activities of continuing operations in the year ended December 31, 2013, included capital expenditures of $345.9 million, and an increase in restricted cash of $1.6 million, partially offset by $2.3 million of net cash inflows related to changes in assets and liabilities associated with investing activities and proceeds from sale of oil and gas properties of $55.5 million.

Cash used in financing activities in the year ended December 31, 2015, related to the repurchase of shares of our Common Stock pursuant to a normal course issuer bid, partially offset by proceeds from issuance of shares of our Common Stock upon the exercise of stock options Cash provided by financing activities of continuing operations in the years ended December 31, 2014 and 2013 related to proceeds from issuance of shares of our Common Stock upon the exercise of stock options.

Off-Balance Sheet Arrangements

As at December 31, 2015, 2014 and 2013 we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2015:

Contractual Obligations	Total	Less than 1 Year	1 to 3 Years	4 to 5 Years	More than 5 Years
(Thousands of U.S. Dollars)					
Oil transportation services	$18,441	$3,650	$7,280	$7,280	$231
Drilling, completions and seismic	7,572	2,918	4,654	—	—
Operating leases	7,140	3,103	4,036	1	—
Software and telecommunication	479	351	128	—	—
Total	$33,632	$10,022	$16,098	$7,281	$231

The above table does not reflect estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties and other long-term liabilities, as we cannot determine with accuracy the timing of such payments. Information regarding our asset retirement obligation can be found in Note 8 to the Consolidated Financial Statements, Asset Retirement Obligation, in Item 8 “Financial Statements and Supplementary Data”,

At December 31, 2015, we had provided promissory notes totaling $76.5 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

As is customary in the oil and gas industry, we may at times have commitments in place to reserve or earn certain acreage positions or wells. If we do not meet such commitments, the acreage positions or wells may be lost and associated penalties may be payable.

Critical Accounting Policies and Estimates

The preparation of financial statements under GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as well as the revenues and expenses reported and disclosure of contingent liabilities. Changes in these estimates related to judgments and assumptions will occur as a result of changes in facts and circumstances or discovery of new information, and, accordingly, actual results could differ from amounts estimated.

On a regular basis we evaluate our estimates, judgments and assumptions. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material. The areas of accounting and the associated critical estimates and assumptions made are discussed below.

Full Cost Method of Accounting, Proved Reserves, DD&A and Impairments of Oil and Gas Properties

We follow the full cost method of accounting for our oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 to our annual consolidated financial statements. Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations ("ARO"), and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

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. The ceiling test limits pooled costs to the aggregate of the discounted estimated after-tax future net revenues from proved oil and gas properties, plus the lower of cost or estimated fair value of unproved properties less any associated tax effects.

If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expenses in future periods. The ceiling limitation is imposed separately for each country in which we have oil and gas properties. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Our estimates of proved oil and gas reserves are a major component of the depletion and full cost ceiling calculations. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the amount and timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data.

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 United States as prescribed by the Society of Petroleum Engineers. Reserve estimates are evaluated at least annually by independent qualified reserves consultants.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and distance from market. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2015, ceiling tests were based on wellhead prices per BOE as of the first day of each month within that twelve month period of $43.51 for Colombia and $37.72 for Brazil.

Because the ceiling test calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. Historical oil and gas prices for any particular 12-month period can be either higher or lower than our price forecast. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Our Reserves Committee 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.

We assessed our oil and gas properties for impairment as at December 31, 2015, and recorded ceiling test impairment losses of $232.4 million in our Colombia cost center, and $46.9 million in our Brazil cost center, related to lower oil prices. In the year ended December 31, 2015, we also recorded impairment losses in our Peru cost center of $41.9 million, related to costs incurred on Block 95. In the year ended December 31, 2014, we recorded an impairment loss of unproved properties in our Peru cost center of $265.1 million due to the lack of continued investment planned for Block 95. In the year ended December 31, 2013, we recorded a ceiling test impairment loss of $2.0 million in our Brazil cost center as a result of lower realized prices and increased operating costs.

Holding all factors constant other than benchmark oil prices, it is reasonably likely that we will experience ceiling test impairment losses in our Brazil and Colombia cost centers in the first quarter of 2016. The calculation excludes the effect of our acquisitions of Petroamerica and PGC which closed subsequent to year end.

It is difficult to predict with reasonable certainty the amount of expected future impairment losses given the many factors impacting the asset base and the cash flows used in the prescribed U.S. GAAP ceiling test calculation. These factors include, but are not limited to, future commodity pricing, royalty rates in different pricing environments, operating costs and negotiated savings, foreign exchange rates, capital expenditures timing and negotiated savings, production and its impact on depletion and cost base, upward or downward reserve revisions as a result of ongoing exploration and development activity, and tax attributes. Subject to these factors and inherent limitations, we believe that ceiling test impairment losses in the first quarter of 2016 could exceed $8 million in Brazil and $131 million in Colombia. The calculation of the impact of lower commodity prices on our estimated ceiling test calculation was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of benchmark oil prices. Therefore, this calculation strictly isolates the impact of commodity prices on the prescribed GAAP ceiling test. This calculation was based on pro forma Brent oil price of $48.82 per bbl for the 12 months ended March 31, 2016. These pro forma oil prices were calculated using a 12-month unweighted arithmetic average of oil prices, and included the oil prices on the first day of the month for the nine months ended December 2015, and, for the three months ended March 2016, estimated oil prices using the forward price curve forecast for the first quarter of 2015 of our independent reserves evaluator dated January 1, 2016.

As noted above, actual cash flows may be materially affected by other factors. For example, in Colombia, cash royalties are levied at lower rates in low oil price environments and foreign exchange rates can materially impact the deferred tax component of the asset base, operating costs, and the income tax calculation. In Brazil, foreign exchange rates can materially impact operating costs and the income tax calculation.

Holding all factors constant other than benchmark oil prices and related royalty rates, we do not expect any downward adjustment to our consolidated NAR reserve volumes during the first quarter of 2016. This disclosure is based on a pro forma Brent oil price of $48.82 per bbl for the 12 months ended March 31, 2016, calculated as described above.

Unproved properties

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. Unproved properties, the costs of which are individually significant, are assessed individually by considering seismic data, plans or requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans and political, economic and market conditions. 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. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to amortization. The transfer of costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, seismic evaluations, the assignment of proved reserves, availability of capital and other factors. For countries where a reserve base has not yet been established, the impairment is charged to earnings.

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 ARO 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 ARO in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities. In arriving at amounts recorded, we make numerous assumptions and judgments with respect to the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements, inflation factors, credit-adjusted risk-free discount rates and changes in legal, regulatory, environmental and political environments. Because costs typically extend many years into the future, estimating future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A.
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.

Allocation of Consideration Transferred in Business Combinations

The acquisition of properties in Brazil in 2012 was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recorded at their fair values at the acquisition date. The fair value of the consideration transferred was equal to the fair value of the net assets acquired and no gain or goodwill was recorded on acquisition. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, was subject to estimates which include various assumptions including the fair value of proved and unproved reserves of the assets acquired as well as future production and development costs and future oil and gas prices.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both oil and gas properties and non-oil and gas properties, the lower future net income will be as a result of higher future DD&A expenses. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling write down in the event that future oil and gas prices drop below the price forecast used to originally determine fair value.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over net identifiable assets acquired and liabilities assumed. The goodwill on our balance sheet resulted from the Solana Resources Limited and Argosy Energy International L.P. acquisitions, in 2008 and 2006 respectively, and relates entirely to the Colombia reporting unit.

At each reporting date, we assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. Changes in our future cash flows, operating results, growth rates, capital expenditures, cost of capital, discount rates, stock price or related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

The two-step goodwill impairment test would require a comparison of the fair value of each reporting unit 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 would write down the goodwill to the implied fair value of the goodwill through a charge to expense. The most significant judgments involved in estimating the fair values of our reporting units would relate to the valuation of our property and equipment. A lower goodwill value decreases the likelihood of an impairment charge. Unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

At December 31, 2015, we performed a valuation of our Colombia reporting unit and passed the first step of the goodwill impairment test at each of the low, medium, and high valuation cases. Ceiling test impairment losses in our Colombian cost center of $232.4 million net of the associated deferred tax recovery of $91.7 million reduced the carrying value of the reporting unit in 2015 by $140.7 million. Additionally, forward curve oil prices as at December 31, 2015, were higher after the first two years of cash flows than those used in the ceiling test impairment calculation. This reduction in carrying value combined with increased reserves and forward curve oil prices as at December 31, 2015, resulted in no impairment of goodwill.

Income Taxes

We follow the liability method of accounting for income taxes whereby we recognize deferred income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

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, we consider 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.

Our effective tax rate is based on pre-tax income and the tax rates applicable to that income in the various jurisdictions in which we operate. An estimated effective tax rate for the year is applied to our quarterly operating results. In the event that there is a significant unusual or discrete item recognized, or expected to be recognized, in our quarterly operating results, the tax attributable to that item would be separately calculated and recorded at the same time as the unusual or discrete item. We consider the resolution of prior-year tax matters to be such items. Significant judgment is required in determining our effective tax rate and in evaluating our tax positions. We establish reserves when it is more likely than not that we will not realize the full tax benefit of the position. We adjust these reserves in light of changing facts and circumstances.

We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts.

Legal and Other Contingencies

A provision for legal and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management’s judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. Management closely monitors known and potential legal and other contingencies and periodically determines when we should record losses for these items based on information available to us.

Stock-Based Compensation

Our stock-based compensation cost is measured based on the fair value of the award on the grant date. The compensation cost is recognized net of estimated forfeitures over the requisite service period. GAAP requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

We utilize the Black-Scholes option pricing model to measure the fair value of all of our stock options. The use of such models requires substantial judgment with respect to expected life, volatility, expected returns and other factors. Expected volatility is based on the historical volatility of our shares. We use historical experience for exercises to determine expected life. We are responsible for determining the assumptions used in estimating the fair value of our share based payment awards.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (“ASU”) 2014-09, “Revenue from Contracts with Customers". The ASU creates a single source of revenue guidance for all companies in all industries and requires revenue recognition to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 sets forth a new revenue recognition model that requires identifying the contract, identifying the performance obligations, determining the transaction price, allocating the transaction price to performance obligations and recognizing the revenue upon satisfaction of performance obligations. The amendments in the ASU can be applied either retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the update recognized at the date of the initial application along with additional disclosures. In August 2015, the FASB issued ASU 2015-14, “Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU defers the effective date of the new revenue recognition model by one year. As a result, the guidance will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. We are currently assessing the impact the new standard will have on its consolidated financial position, results of operations, cash flows and disclosure.

In July 2015, the FASB issued ASU 2015-11, “Simplifying the Measurement of Inventory". The ASU provides guidance for the subsequent measurement of inventory and requires that inventory that is measured using average cost be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The implementation of this update is not expected to materially impact our consolidated financial position, results of operations or cash flows or disclosure.
In September 2015, the FASB issued ASU 2015-16, "Simplifying the Accounting for Measurement-Period Adjustments". ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for fiscal years and interim reporting periods within those fiscal years, beginning after December 15, 2015. Prospective adoption is required. This ASU is not expected to have a material impact on our consolidated financial position, results of operations or cash flows or disclosure.

In November 2015, the FASB issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes". ASU 2015-17 requires that deferred tax liabilities and assets be classified as long-term in a classified balance sheet. ASU 2015-17 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2016. Early application is permitted. The amendments in this ASU may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We implemented this update retrospectively in our consolidated financial statements for the year ended December 31, 2015, so that the balance sheet is presented on a comparable basis. Deferred tax liabilities and assets of $1.0 million and $1.6 million, respectively, have been reclassified from current to long-term in our December 31, 2014 balance sheet. The implementation of this update did not impact our consolidated results of operations or cash flows.

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU is not expected to have a material impact our consolidated financial position, results of operations or cash flows or disclosure.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our principal market risk relates to oil prices. Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand imbalance and many other market factors outside of our control. Oil prices started falling in July 2014 and fell dramatically during the period December 2014 to March 2015. Prices have remained low and volatile. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to West Texas Intermediate ("WTI") or Brent and adjusted for quality each month.

Foreign currency risk

Foreign currency risk is a factor for our company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil. In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars or are based on U.S. dollar prices. In Brazil, prices for oil are in U.S.

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

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $10,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

We have engaged, from time to time, in non-deliverable foreign exchange contracts to buy or sell Colombian pesos in order to fix the exchange rate of our income tax installments and payments in Colombia. At December 31, 2015, we did not have any open foreign currency derivative positions.

The table below provides information about our foreign currency forward exchange agreements at December 31, 2014, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. The increase or decrease in the value of the forward contract is offset by the increase or decrease to the U.S. dollar equivalent of the Colombian peso current tax liabilities. We do not hold any of these investments for trading purposes.

As at December 31, 2014

Currency	Contract Type	Notional (Millions of Colombian pesos)	Weighted Average Fixed Rate Received (Colombian pesos - U.S. Dollars)	Fair Value of the Forward Contracts (thousands of U.S. Dollars)	Expiration
Colombian pesos	Buy	51,597.5	2,006	(4,175)	February and April 2015
Colombian pesos	Sell	10,275.3	1,895	1,118	February 2015

Interest Rate Risk

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

Equity Investment in Madalena Energy Inc.

We hold an equity investment in Madalena, received as consideration in the sale of our Argentina business unit, which closed June 25, 2014. We hold 29,831,537 shares of Madalena which had a value of $6.3 million and $7.6 million at December 31, 2015 and 2014, respectively, and represented approximately 5.5% of Madalena's outstanding shares at

December 31, 2015 and 2014. These shares trade on the TSX Venture Exchange and as such are subject to changes in value that are outside of our control. We may face other market related obstacles such as trading volume and value in divesting these shares.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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, 2015 and 2014, and the related consolidated statements of operations and retained earnings, cash flows and shareholders' equity for each of the years in the three-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) and Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated 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, such consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

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, 2015, based on the criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
February 26, 2016
Calgary, Canada

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

	Year Ended December 31,		
	2015	2014	2013
OIL AND NATURAL GAS SALES	$276,011	$559,398	$646,955
EXPENSES			
Operating	75,565	89,753	91,223
Transportation	40,204	24,196	18,949
Depletion, depreciation and accretion	176,386	185,877	200,851
Asset impairment (Note 6)	323,918	265,126	2,000
General and administrative	32,353	51,249	41,115
Severance expenses (Note 13)	8,990	—	—
Equity tax (Note 9)	3,769	—	—
Foreign exchange gain	(17,242)	(39,535)	(18,693)
Financial instruments loss (Note 12)	2,027	4,722	—
Other loss (Note 11)	—	—	4,400
Other gain (Note 11)	(502)	(2,000)	—
	645,468	579,388	339,845
INTEREST INCOME	1,369	2,856	2,174
(LOSS) INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(368,088)	(17,134)	309,284
INCOME TAX (EXPENSE) RECOVERY			
Current (Note 9)	(15,383)	(92,865)	(157,126)
Deferred (Note 9)	115,442	(34,350)	28,865
	100,059	(127,215)	(128,261)
(LOSS) INCOME FROM CONTINUING OPERATIONS	(268,029)	(144,349)	181,023
Loss from discontinued operations, net of income taxes (Note 3)	—	(26,990)	(54,735)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	(268,029)	(171,339)	126,288
INCOME (LOSS) PER SHARE			
BASIC			
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.94)	$(0.51)	$0.64
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	—	(0.09)	(0.19)
NET INCOME (LOSS)	$(0.94)	$(0.60)	$0.45
DILUTED			
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.94)	$(0.51)	$0.63
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	—	(0.09)	(0.19)
NET INCOME (LOSS)	$(0.94)	$(0.60)	$0.44
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 7)	285,333,869	284,715,785	282,808,497
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 7)	285,333,869	284,715,785	286,127,897

(See notes to the consolidated financial statements)

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

	As at December 31,	
	2015	2014
ASSETS		
Current Assets		
Cash and cash equivalents	$145,342	$331,848
Accounts receivable (Note 5)	29,217	83,227
Marketable securities (Note 12)	6,250	7,586
Inventory (Note 5)	19,056	17,298
Taxes receivable	28,635	15,843
Other current assets	5,940	7,836
Total Current Assets	234,440	463,638
Oil and Gas Properties (using the full cost method of accounting)		
Proved	469,589	801,075
Unproved	310,771	316,856
Total Oil and Gas Properties	780,360	1,117,931
Other capital assets	8,633	11,013
Total Property, Plant and Equipment (Note 6)	788,993	1,128,944
Other Long-Term Assets		
Taxes receivable	8,276	9,684
Other long-term assets	11,828	9,203
Goodwill (Note 2)	102,581	102,581
Total Other Long-Term Assets	122,685	121,468
Total Assets	$1,146,118	$1,714,050
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 10)	$70,778	$187,831
Foreign currency derivative (Note 12)	—	3,057
Taxes payable	1,067	25,412
Asset retirement obligation (Note 8)	2,146	8,026
Total Current Liabilities	73,991	224,326
Long-Term Liabilities		
Deferred tax liabilities (Note 9)	34,592	176,364
Asset retirement obligation (Note 8)	31,078	27,786
Other long-term liabilities	4,815	8,889
Total Long-Term Liabilities	70,485	213,039
Commitments and Contingencies (Note 11)		
Subsequent Events (Note 16)		
Shareholders' Equity		
Common Stock (Note 7) (273,442,799 and 276,072,351 shares of Common Stock and 8,572,066 and 10,119,745 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2015 and December 31, 2014, respectively)	10,186	10,190

Additional paid in capital	1,019,863	1,026,873
(Deficit) retained earnings	(28,407)	239,622
Total Shareholders’ Equity	1,001,642	1,276,685
Total Liabilities and Shareholders’ Equity	$1,146,118	$1,714,050

(See notes to the consolidated financial statements)

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

	Year Ended December 31,		
	2015	2014	2013
Operating Activities			
Net income (loss)	$(268,029)	$(171,339)	$126,288
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Loss from discontinued operations, net of income taxes (Note 3)	—	26,990	54,735
Depletion, depreciation and accretion	176,386	185,877	200,851
Asset impairment (Note 6)	323,918	265,126	2,000
Deferred tax (recovery) expense (Note 9)	(115,442)	34,350	(28,865)
Non-cash stock-based compensation	2,091	5,451	8,002
Financial instruments loss (Note 12)	2,027	4,722	—
Unrealized foreign exchange gain	(8,380)	(30,941)	(16,103)
Cash settlement of foreign currency derivatives	(3,749)	4,661	—
Cash settlement of asset retirement obligation (Note 8)	(6,217)	(796)	(2,068)
Other loss (Note 11)	—	—	4,400
Other gain (Note 11)	(502)	(2,000)	—
Equity tax	—	(3,283)	(3,345)
Net change in assets and liabilities from operating activities of continuing operations (Note 15)	(39,798)	(97,866)	146,598
Net cash provided by operating activities of continuing operations	62,305	220,952	492,493
Net cash (used in) provided by operating activities of discontinued operations	—	(4,792)	31,064
Net cash provided by operating activities	62,305	216,160	523,557
Investing Activities			
Decrease (increase) in restricted cash	465	(96)	(1,590)
Additions to property, plant and equipment	(156,639)	(391,526)	(345,865)
Changes in non-cash investing working capital	(76,844)	44,499	2,274
Proceeds from oil and gas properties (Note 6)	—	—	55,524
Net cash used in investing activities of continuing operations	(233,018)	(347,123)	(289,657)
Proceeds from sale of Argentina business unit, net of cash sold and transaction costs	—	42,755	—
Net cash used in investing activities of discontinued operations	—	(12,384)	(18,799)
Net cash provided by (used in) investing activities of discontinued operations	—	30,371	(18,799)
Net cash used in investing activities	(233,018)	(316,752)	(308,456)
Financing Activities			
Repurchase of shares of Common Stock (Note 7)	(9,999)	—	—
Proceeds from issuance of shares of Common Stock (Note 7)	722	11,140	3,771
Net cash (used in) provided by financing activities	(9,277)	11,140	3,771
Foreign exchange loss on cash and cash equivalents	(6,516)	(7,500)	(2,696)
Net (decrease) increase in cash and cash equivalents	(186,506)	(96,952)	216,176

Cash and cash equivalents, beginning of year	331,848	428,800	212,624
Cash and cash equivalents, end of year	$145,342	$331,848	$428,800

Supplemental cash flow disclosures (Note 15)

(See notes to the consolidated financial statements)

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

	Year Ended December 31,		
	2015	2014	2013
Share Capital			
Balance, beginning of year	$10,190	$10,187	$7,986
Issuance of Common Stock	—	3	2,201
Repurchase of Common Stock	(4)		—
Balance, end of year	10,186	10,190	10,187
Additional Paid in Capital			
Balance, beginning of year	1,026,873	1,008,760	998,772
Exercise of stock options (Note 7)	722	11,137	1,570
Stock-based compensation (Note 7)	2,263	6,976	8,418
Repurchase of Common Stock (Note 7)	(9,995)	—	—
Balance, end of year	1,019,863	1,026,873	1,008,760
Retained Earnings (Deficit)			
Balance, beginning of year	239,622	410,961	284,673
Net income (loss)	(268,029)	(171,339)	126,288
Balance, end of year	(28,407)	239,622	410,961
Total Shareholders' Equity	$1,001,642	$1,276,685	$1,429,908

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2015, 2014 and 2013
(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

Gran Tierra Energy Inc., a Nevada corporation (the “Company” or “Gran Tierra”), is a publicly traded oil and gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties. The Company’s principal business activity is in Colombia. The Company also has business activities in Peru and Brazil, and until June 25, 2014, had business activities in Argentina.

2. Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”). The Company believes that the information and disclosures presented are adequate to ensure the information presented is not misleading.

Significant accounting policies are:

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated.

Discontinued operations

On June 25, 2014, the Company completed the sale of its Argentina business unit and the discontinued operations criteria of Accounting Standards Codification ("ASC") 205-20, “Discontinued Operations”, were met. Therefore, the results of the Company’s Argentina business unit are reflected separately as loss from discontinued operations, net of income taxes, in the consolidated statement of operations for the two years ended December 31, 2014, on a line immediately after “Loss or income from continuing operations.” Additionally, cash flows of the Company’s Argentina business unit are reflected separately in the consolidated statement of cash flows for the two years ended December 31, 2014, as cash provided by or used in operating and investing activities of discontinued operations. See Note 3, “Discontinued Operations,” for additional disclosure. The Company did not recognize depletion, depreciation and accretion ("DD&A") expenses for the Argentina business unit subsequent to May 29, 2014, the date the assets were classified as held for sale.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows; depreciation, depletion, amortization and impairment (“DD&A”); impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to depletion to the depletable base; asset retirement obligations; determining the value of the consideration transferred and the net identifiable assets acquired and liabilities assumed in connection with business combinations and determining goodwill; assessments of the likely outcome of legal and other contingencies; income taxes; stock-based compensation; and determining the fair value of foreign currency derivatives. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates and actual results may differ from these estimates.

Cash and cash equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted cash

Restricted cash is included in other current assets and other long-term assets on the Company's balance sheet. Restricted cash comprises cash and cash equivalents pledged to secure letters of credit and to settle asset retirement obligations. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. Cash and claims to cash that are restricted as to withdrawal or use for other than current operations or are designated for expenditure in the acquisition or construction of long-term assets are excluded from the current asset classification.

Allowance for doubtful accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. The allowance for doubtful receivables was $nil at December 31, 2015, and 2014.

Marketable securities

The Company acquired investments in marketable securities in connection with the sale of its Argentina business unit in 2014. Marketable securities are classified as trading securities, in accordance with ASC 320, “Investments – Debt and Equity Securities”, and are recorded in the consolidated balance sheet at fair value. The Company classifies trading securities as current or non-current based on the intent of management, the nature of the trading securities and whether they are readily available for use in current operations. Gains or losses on trading securities are recorded in the statement of operations as financial instruments gains or losses.

Foreign currency derivatives

The Company has, from time to time, purchased Colombian peso non-deliverable forward contracts for purposes of fixing exchange rates at which it will purchase or sell Colombian pesos to settle its income tax installment payments. The Company does not intend to issue or hold derivative financial instruments for speculative trading purposes.

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

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

Inventory

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

Income taxes

Income taxes are recognized using the liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the consolidated financial statement carrying amounts of existing assets and liabilities and their respective tax base, and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. Valuation allowances are provided if, after considering available evidence, it is not more likely than not that some or all of the deferred tax assets will be realized.

The tax benefit from an uncertain tax position is recognized when it is more likely than not, based on the technical merits of the position, that the position will be sustained on examination by the taxing authorities. Additionally, the amount of the tax benefit recognized is the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the Company presumes that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The Company recognizes potential penalties and interest related to unrecognized tax benefits as a component of income tax expense.

Oil and gas properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as defined by the Securities and Exchange Commission ("SEC"). Under this method, the Company capitalizes all acquisition, exploration and development costs incurred for the purpose of finding oil and natural gas reserves, including salaries, benefits and other internal costs directly attributable to these activities. Costs associated with production and general corporate activities; however, are expensed as incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and natural gas properties. Separate cost centers are maintained for each country in which the Company incurs costs.

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion. The costs of unproved properties are excluded from the amortization base until the properties are evaluated. The cost of exploratory dry wells is transferred to proved properties, and thus is subject to amortization, immediately upon determination that a well is dry in those countries where proved reserves exist.

The Company performs a ceiling test calculation each quarter in accordance with SEC Regulation S-X Rule 4-10. In performing its quarterly ceiling test, the Company limits, on a country-by-country basis, the capitalized costs of proved oil and natural gas properties, net of accumulated depletion and deferred income taxes, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the costs being amortized. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to net income or loss. Any such write-down will reduce earnings in the period of occurrence and results in a lower DD&A rate 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.

The Company calculates future net cash flows by applying the unweighted average of prices in effect on the first day of the month for the preceding 12-month period, adjusted for location and quality differentials. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts.

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the depletable base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. This evaluation considers, among other factors, seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to depletion. For countries where a reserve base has not yet been established, the impairment is charged to earnings.

In exploration areas, related seismic costs are capitalized in unproved property and evaluated as part of the total capitalized costs associated with a property. Seismic costs related to development projects are recorded in proved properties and therefore subject to depletion as incurred.

Gains and losses on the sale or other disposition of oil and natural gas properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

Asset retirement obligation

The Company records an estimated liability for future costs associated with the abandonment of its oil and gas properties including the costs of reclamation of drilling sites. The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to the related oil and gas properties. The fair value of an asset retirement obligation is measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value, while the asset retirement cost is amortized over the estimated productive life of the related assets. The accretion of the asset retirement obligation and amortization of the asset retirement cost are included in DD&A. If estimated future costs of an asset retirement obligation change, an adjustment is recorded to both the asset retirement obligation and oil and gas properties. Revisions to the estimated asset retirement obligation can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Other capital assets

Other capital assets, including additions and replacements, are recorded at cost upon acquisition and include furniture, fixtures and leasehold improvement, computer equipment and automobiles. Depreciation is provided using the declining-balance method at a 30% annual rate for furniture and fixtures, computer equipment and automobiles. Leasehold improvements are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expense as incurred.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed. The Company assesses qualitative factors annually, or more frequently if necessary, to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. The impairment test requires allocating goodwill and certain other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared with 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, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for the Company's reporting units, the fair values of the reporting units are estimated based upon estimated future cash flows of the reporting unit.

The Company recorded $87.6 million of goodwill in relation to the acquisition of Solana Resources Limited ("Solana") in 2008 and $15.0 million of goodwill in relation to the Argosy Energy International L.P. acquisition in 2006. The goodwill relates entirely to the Colombia reportable segment. The Company performed a quantitative assessment of goodwill at December 31, 2015, and based on this assessment, no impairment of goodwill was identified.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable, the sale is evidenced by a contract and collection of the revenue is reasonably assured. In Colombia, the sales point for the Company's sales varies depending on the delivery point but includes the Port of Tumaco on the Pacific coast of Colombia, the purchaser's facilities and when oil is loaded into a truck at Gran Tierra's loading facility or an export tanker. In Brazil, the sales point is either the Petróleo Brasileiro S.A station or the purchaser's facility.

Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company grants time-vested restricted stock units ("RSUs") to officers, employees and consultants. RSUs entitle the holder to receive, at the option of the Company, either the underlying number of shares of the Company's

Common Stock upon vesting of such shares or a cash payment equal to the value of the underlying shares. The Company's practice is to settle RSUs in cash and, therefore, RSUs are accounted for as liability instruments. Compensation expense for RSUs granted is based on the estimated fair value, which is determined using the closing share price, at each reporting date, and the expense, net of estimated forfeitures, is recognized over the requisite service period using the accelerated method, with a corresponding change to liabilities. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures.

Additionally, the Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. The Company follows the fair-value based method of accounting for stock options granted. Compensation expense for options granted is based on the estimated fair value, using the Black-Scholes option pricing model, at the time of grant and the expense, net of estimated forfeitures, is recognized over the requisite service period using the accelerated method. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures . The Company uses historical data to estimate expected term used in the Black-Scholes option pricing model, option exercises and employee departure behavior. Expected volatilities used in the fair value estimate are based on historical volatility of the Company’s shares. The risk-free rate for periods within the expected term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant.

Stock-based compensation expense relating to RSUs and stock options is capitalized as part of oil and natural gas properties or expensed as part of operating expenses or general and administrative (“G&A”) expenses, as appropriate.

Foreign currency translation

The functional currency of the Company, including its subsidiaries, is the United States dollar. Monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date and non-monetary items are translated at historical exchange rates. Revenue and expense items are translated in a manner that produces substantially the same reporting currency amounts that would have resulted had the underlying transactions been translated on the dates they occurred.

Depreciation or amortization of assets is translated at the historical exchange rates similar to the assets to which they relate.
Gains and losses resulting from foreign currency transactions, which are transactions denominated in a currency other than the entity’s functional currency, are recognized in net income or loss.

Net income or loss per share

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

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers". The ASU creates a single source of revenue guidance for all companies in all industries and requires revenue recognition to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 sets forth a new revenue recognition model that requires identifying the contract, identifying the performance obligations, determining the transaction price, allocating the transaction price to performance obligations and recognizing the revenue upon satisfaction of performance obligations. The amendments in the ASU can be applied either retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the update recognized at the date of the initial application along with additional disclosures. In August 2015, the FASB issued ASU 2015-14, “Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU defers the effective date of the new revenue recognition model by one year. As a result, the guidance will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact the new standard will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Simplifying the Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, “Simplifying the Measurement of Inventory". The ASU provides guidance for the subsequent measurement of inventory and requires that inventory that is measured using average cost be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The implementation of this update is not expected to materially impact the Company’s consolidated financial position, results of operations or cash flows or disclosure.

Simplifying the Accounting for Measurement-Period Adjustments

In September 2015, the FASB issued ASU 2015-16, "Simplifying the Accounting for Measurement-Period Adjustments". ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. ASU 2015-16 is effective for fiscal years and interim reporting periods within those fiscal years, beginning after December 15, 2015. Prospective adoption is required. This ASU is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU 2015-17, "Balance Sheet Classification of Deferred Taxes". ASU 2015-17 requires that deferred tax liabilities and assets be classified as long-term in a classified balance sheet. ASU 2015-17 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2016. Early application is permitted. The amendments in this ASU may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. The Company implemented this update retrospectively in its consolidated financial statements for the year ended December 31, 2015, so that the balance sheet is presented on a comparable basis. Deferred tax liabilities and assets of $1.0 million and $1.6 million, respectively, have been reclassified from current to long-term in the Company's December 31, 2014 balance sheet. The implementation of this update did not impact the Company’s consolidated results of operations or cash flows.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

3. Discontinued Operations

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

Accordingly, the results of the Company’s Argentina business unit are classified as “Loss from discontinued operations, net of income taxes” on the consolidated statements of operations for the two years ended December 31, 2014. Additionally, cash flows of the Company’s Argentina business unit are presented separately in the consolidated statement of cash flows for the two years ended December 31, 2014, as cash provided by or used in operating and investing activities of discontinued operations.

Revenue and other income and loss from discontinued operations, net of income taxes, for the two years ended December 31, 2014, were as follows:

	Year Ended December 31,	
(Thousands of U.S. Dollars)	2014	2013
Revenue and other income	$ 31,985	$ 74,514

Loss income from operations of discontinued operations before income taxes	$ (6,252)	$ (47,448)
Income tax expense	(1,458)	(7,287)
Loss from operations of discontinued operations	(7,710)	(54,735)
Loss on sale before income taxes	(18,235)	—
Income tax expense	(1,045)	—
Loss on sale	(19,280)	—
Loss from discontinued operations, net of income taxes	$ (26,990)	$ (54,735)

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Results from discontinued operations before income taxes for the year ended December 31, 2014, were calculated to the date of sale of June 25, 2014. The Company classified the Argentina business unit as held for sale at May 29, 2014. In the year ended December 31, 2013, the Company recorded a ceiling test impairment loss of $30.8 million in the Company's Argentina cost center as a result of deferred investment and inconclusive waterflood results.

4. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company’s reportable segments are Colombia, Peru and Brazil based on geographic organization. The All Other category represents the Company’s corporate activities. The Company evaluates reportable segment performance based on income or loss from continuing operations before income taxes.

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

	Year Ended December 31, 2015				
(Thousands of U.S. Dollars, except per unit of sales amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$269,035	$—	$6,976	$—	$276,011
Interest income	294	2	218	855	1,369
DD&A expenses	167,701	789	6,183	1,713	176,386
DD&A - per unit of sales	25.90	—	32.66	—	26.47
Asset impairment	235,069	41,916	46,933	—	323,918
General and administrative	9,805	3,800	2,708	16,040	32,353
Loss from continuing operations before income taxes	(238,463)	(51,675)	(54,968)	(22,982)	(368,088)
Segment capital expenditures	87,723	50,419	19,989	1,095	159,226

	Year Ended December 31, 2014				
(Thousands of U.S. Dollars, except per unit of sales amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$532,196	$—	$27,202	$—	$559,398
Interest income	569	1	1,604	682	2,856
DD&A expenses	174,063	690	9,932	1,192	185,877
DD&A - per unit of sales	27.07	—	30.09	—	27.49
Asset impairment	—	265,126	—	—	265,126
General and administrative	19,431	6,448	3,698	21,672	51,249
Income (loss) from continuing operations before income taxes	279,924	(274,207)	5,921	(28,772)	(17,134)
Segment capital expenditures	214,928	174,158	24,278	2,868	416,232

	Year Ended December 31, 2013				
(Thousands of U.S. Dollars, except per unit of sales amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$624,410	$—	$22,545	$—	$646,955
Interest income	623	27	909	615	2,174
DD&A expenses	184,697	362	14,761	1,031	200,851
DD&A - per unit of sales	27.23	—	61.75	—	28.60
Asset impairment	—	—	2,000	—	2,000
General and administrative	16,996	5,524	2,231	16,364	41,115
Income (loss) from continuing operations before income taxes	336,179	(7,067)	(2,650)	(17,178)	309,284

Segment capital expenditures (1)	188,547	82,954	23,039	775	295,315

(1) In 2013, segment capital expenditures are net of proceeds of: $54.0 million relating to termination of a farm-in agreement in Brazil; and $1.5 million relating to the Company's sale of its 15% working interest in the Mecaya Block in Colombia (Note 6).

	As at December 31, 2015				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$574,351	$95,069	$115,552	$4,021	$788,993
Goodwill	102,581	—	—	—	$102,581
All other assets	93,479	21,111	2,236	137,718	$254,544
Total Assets	$770,411	$116,180	$117,788	$141,739	$1,146,118

	As at December 31, 2014				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$888,822	$87,028	$148,457	$4,637	$1,128,944
Goodwill	102,581	—	—	—	$102,581
All other assets	157,549	40,613	14,724	269,639	$482,525
Total Assets	$1,148,952	$127,641	$163,181	$274,276	$1,714,050

In the year ended December 31, 2015, the Company had four significant customers which accounted for 43%, 15%, 13% and 12% of the Company's consolidated oil and natural gas sales. In the years ended December 31, 2014 and 2013, the Company had two significant customers which accounted for 52% and 32%, and 46% and 42%, respectively, of the Company's consolidated oil and natural gas sales.

5. Accounts Receivable and Inventory

Accounts Receivable

	As at December 31,	
(Thousands of U.S. Dollars)	2015	2014
Trade	$26,924	$80,058
Other	2,293	3,169
	$29,217	$83,227

Inventory

At December 31, 2015, oil and supplies inventories were $17.8 million and $1.3 million, respectively (December 31, 2014 - $15.2 million and $2.1 million, respectively). In the year ended December 31, 2015, the Company recorded oil inventory impairment of $2.6 million (year ended December 31, 2014 - $nil, year ended December 31, 2013 - $nil) related to lower oil prices (Note 6).

6. Property, Plant and Equipment

	As at December 31,	
(Thousands of U.S. Dollars)	2015	2014
Oil and natural gas properties		
Proved	$1,998,330	$1,876,371
Unproved	310,771	316,856
	2,309,101	2,193,227
Other	28,342	27,287
	2,337,443	2,220,514

Accumulated depletion, depreciation and impairment	(1,548,450)	(1,091,570)
	$788,993	$1,128,944

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In the year ended December 31, 2015, the Company recorded ceiling test impairment losses of $232.4 million in its Colombia cost center, and $46.9 million in its Brazil cost center, related to lower oil prices. The Company follows the full cost method of accounting for its oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated “ceiling”. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year and it should not be assumed that estimates of future net revenues represent the fair market value of the Company's reserves.

In the year ended December 31, 2015, the Company recorded an impairment loss in its Peru cost center of $41.9 million related to costs incurred on Block 95. On February 19, 2015, the Company made the decision to cease all further development expenditures on the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security. In the year ended December 31, 2014, the Company recorded an impairment loss in its Peru cost center of $265.1 million related to costs incurred on Block 95.

In the year ended December 31, 2013, the Company recorded a ceiling test impairment loss of $2.0 million in its Brazil cost center as a result of lower realized prices and increased operating costs.

Asset impairment for the three years ended December 31, 2015, was follows:

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2015	2014	2013
Impairment of oil and gas properties	$321,285	$265,126	$2,000
Impairment of inventory (Note 5)	2,633	—	—
	$323,918	$265,126	$2,000

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2015, was $177.9 million (year ended December 31, 2014 - $187.9 million; year ended December 31, 2013 - $194.2 million). A portion of depletion and depreciation expense was recorded as inventory in each year and adjusted for inventory changes.

In 2013, the Company received a net payment of $54.0 million (before income taxes) from a third party in connection with the termination of a farm-in agreement in Brazil and $1.5 million relating to a sale of its working interest of a block in Colombia.

The Company successfully bid on three blocks in the 2013 Brazil Bid Round 11 administered by Brazil's Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") and, in 2013, paid a signature bonus of $14.4 million upon finalization of the concession agreements.

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Peru and Brazil. As at December 31, 2015, the Company had $147.5 million (December 31, 2014 - $170.5 million) of unproved assets in Colombia, $94.2 million (December 31, 2014 - $85.7 million) of unproved assets in Peru, and $69.1 million (December 31, 2014 - $60.7 million) of unproved assets in Brazil for a total of $310.8 million (December 31, 2014 - $316.9 million). Unproved oil and natural gas properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration warrants whether or not future areas will be developed. The Company expects that approximately 60% of costs not subject to depletion at December 31, 2015, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2015:

(Thousands of U.S. Dollars)	Costs Incurred in 2015	2014	2013	Prior to 2013	Total
Acquisition costs - Colombia	$—	$—	$—	$67,597	$67,597
Acquisition costs - Peru	—	—	—	21,147	21,147
Acquisition costs - Brazil	—	—	—	35,525	35,525
Exploration costs - Colombia	11,151	35,952	20,103	12,697	79,903
Exploration costs - Peru	8,515	31,750	7,301	25,469	73,035
Exploration costs - Brazil	10,639	8,911	14,779	(765)	33,564
Total oil and natural gas properties not subject to depletion	$30,305	$76,613	$42,183	$161,670	$310,771

7. Share Capital

The Company’s authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as Common Stock, par value $0.001 per share, 25 million are designated as Preferred Stock, par value $0.001 per share, and two shares are designated as special voting stock, par value $0.001 per share.

As at December 31, 2015, outstanding share capital consists of 273,442,799 shares of Common Stock of the Company, 4,933,177 exchangeable shares of Gran Tierra Exchangeco Inc., (the "Exchangeco exchangeable shares") and 3,638,889 exchangeable shares of Gran Tierra Goldstrike Inc. (the "Goldstrike exchangeable shares"). The Exchangeco exchangeable shares were issued upon the acquisition of Solana. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. The redemption date for the Exchangeco exchangeable shares and the Goldstrike exchangeable shares is a date to be established by the applicable Board of Directors.

On July 22, 2015, the Company announced that it intended to implement a new share repurchase program (the “2015 Program”) through the facilities of the Toronto Stock Exchange ("TSX"), the NYSE MKT and eligible alternative trading platforms in Canada and the United States. The Company received regulatory approval from the TSX to commence the 2015 Program on July 27, 2015. The Company is able to purchase at prevailing market prices up to 13,831,866 shares of Common Stock, representing 4.98% of the issued and outstanding shares of Common Stock as of July 21, 2015. Shares purchased pursuant to the 2015 Program will be canceled. The 2015 Program will expire on July 29, 2016, or earlier if the 4.98% share maximum is reached. The 2015 Program may be terminated by the Company at any time, subject to compliance with regulatory requirements. As such, there can be no assurance regarding the total number of shares that may be repurchased under the 2015 Program. During 2015, the Company repurchased 4.6 million shares at an average price of $2.19 for total proceeds of $10.0 million.

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.
Balance, December 31, 2014	276,072,351	5,595,118	4,524,627
Options exercised	390,000	—	—
Shares repurchased and canceled	(4,567,136)	—	—
Exchange of exchangeable shares	1,547,595	(661,857)	(885,738)
Shares canceled	(11)	(84)	—
Balance, December 31, 2015	273,442,799	4,933,177	3,638,889

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

Restricted Stock Units and Stock Options

In accordance with the 2007 Equity Incentive Plan, the Company’s Board of Directors is authorized to issue options or other rights to acquire shares of the Company’s Common Stock. On June 27, 2012, the shareholders of Gran Tierra approved an amendment to the Company’s 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares.

The Company grants time-vested RSUs to certain officers, employees and consultants. RSUs entitle the holder to receive, at the option of the Company, either the underlying number of shares of the Company's Common Stock upon vesting of such shares or a cash payment equal to the value of the underlying shares. The Company's practice is to settle RSUs in cash.

Additionally, the Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. Each option permits the holder to purchase one share of Common Stock at the stated exercise price. At the time of grant, the exercise price equals the market price. Options and RSUs generally vest over three years. The Company does not expect to repurchase any shares in the open market to settle any such exercises.

The term of options granted starting May 2013 is five years or three months after the grantee’s end of service to the Company, whichever occurs first. Options granted prior to May 2013 continue to have a term of ten years or three months after the grantee’s end of service to the Company, whichever occurs first. Once an RSU is vested, it is immediately settled and considered to be at the end of its term.

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

	Year Ended December 31,		
	2015	2014	2013
Dividend yield (per share)	Nil	Nil	Nil
Volatility	46% to 50%	39% to 42%	42% to 54%
Weighted average volatility	48%	41%	53%
Risk-free interest rate	1.20% to 1.68%	0.78% to 1.45%	0.3% to 0.7%
Expected term	4-5 years	4-5 years	4-5 years

The following table provides information about RSU and stock option activity for the year ended December 31, 2015:

	RSUs	Options	
	Number of Outstanding Share Units	Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2014	1,236,963	13,790,220	$5.93
Granted	1,041,450	5,346,260	3.08
Exercised	(531,012)	(390,000)	1.85
Forfeited	(731,944)	(1,394,445)	(5.63)
Expired	—	(4,500,478)	(6.78)
Balance, December 31, 2015	1,015,457	12,851,557	$4.60
Exercisable, at December 31, 2015		7,784,678	$5.17
Vested, or expected to vest, at December 31, 2015, through the life of the options		12,494,309	$4.63

For the year ended December 31, 2015, 390,000 shares of Common Stock were issued for cash proceeds of $0.7 million upon the exercise of 390,000 stock options (2014 – 3,029,853; 2013 – 1,306,317). For the year ended December 31, 2015, the Company paid $1.7 million to cash settle RSUs (2014 - $3.4 million and 2013 - $nil).

At December 31, 2015, the weighted average remaining contractual term of outstanding stock options was 3.3 years and of exercisable stock options was 2.7 years.

The weighted average grant date fair value for options granted in the year ended December 31, 2015, was $1.24 (2014 - $2.47; 2013 - $2.62). The weighted average grant date fair value for options vested in the year ended December 31, 2015, was $2.38 (2014 - $3.63; 2013 - $3.94). The total fair value of stock options vested during year ended December 31, 2015, was $6.8 million (2014 - $12.4 million; 2013 - $12.4 million).

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

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2015	2014	2013
Compensation costs for stock options	$2,263	$6,976	$8,418
Compensation costs for RSUs	629	2,559	2,936
	2,892	9,535	11,354
Less: Stock-based compensation costs capitalized	(159)	(1,815)	(2,436)
Stock-based compensation costs expensed	$2,733	$7,720	$8,918

At December 31, 2015, there was $3.9 million (December 31, 2014 - $4.8 million) of unrecognized compensation cost related to unvested stock options and RSUs which is expected to be recognized over a weighted average period of 1.5 years. The weighted-average remaining contractual term of options vested, or expected to vest, at December 31, 2015 was 3.2 years.

Weighted Average Shares Outstanding

	Year Ended December 31,		
	2015	2014	2013
Weighted average number of common and exchangeable shares outstanding	285,333,869	284,715,785	282,808,497
Shares issuable pursuant to stock options	—	—	12,041,260
Shares assumed to be purchased from proceeds of stock options	—	—	(8,721,860)
Weighted average number of diluted common and exchangeable shares outstanding	285,333,869	284,715,785	286,127,897

For the year ended December 31, 2015, 13,432,287 options, on a weighted average basis, (2014 - 15,621,890 options; 2013 - 4,217,082 options) were excluded from the diluted loss per share calculation as the options were anti-dilutive.

8. Asset Retirement Obligation

Changes in the carrying amounts of the asset retirement obligation associated with the Company's oil and natural gas properties were as follows:

	Year Ended December 31,	
(Thousands of U.S. Dollars)	2015	2014
Balance, beginning of year	$35,812	$21,973
Settlements	(6,317)	(1,137)
Liability incurred	1,556	11,956
Liabilities associated with the Argentina business unit sold	—	(10,170)
Accretion	1,313	1,406
Revisions in estimated liability	860	11,784
Balance, end of year	$33,224	$35,812

Asset retirement obligation - current	$2,146	$8,026
Asset retirement obligation - long-term	31,078	27,786
Balance, end of year	$33,224	$35,812

For the year ended December 31, 2015, settlements included cash payments of $6.2 million with the balance in accounts payable and accrued liabilities at December 31, 2015. Revisions in estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. During the year ended December 31, 2014, estimated asset retirement liabilities were increased by $7.6 million to reflect accelerated revised outcome probabilities and their timing as a result of the decision to cease all further development expenditures on the Bretaña Field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. At December 31, 2015, the fair value of assets that are legally restricted for purposes of settling asset retirement obligations was $2.9 million (December 31, 2014 - $2.0 million). These assets are accounted for as restricted cash and included in other current assets and other long-term assets on the Company's balance sheet.

9. Taxes

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

	Year Ended December 31,					
(Thousands of U.S. Dollars)	2015		2014		2013	
(Loss) income from continuing operations before income taxes						
United States	$(14,061	)	$(19,744	)	$(13,566	)
Foreign	(354,027	)	2,610		322,850	
	(368,088	)	(17,134	)	309,284	
	35	%	35	%	35	%
Income tax (recovery) expense from continuing operations expected	(128,831	)	(5,997	)	108,249	
Foreign currency translation adjustments	(187	)	(6,520	)	(7,185	)
Impact of foreign taxes (1)	(13,087	)	27,910		(3,596	)
Other local taxes	2,354		4,433		3,673	
Stock-based compensation	919		2,232		2,724	
Increase in valuation allowance	37,691		94,922		21,423	
Non-deductible third party royalty in Colombia	3,416		9,116		11,073	
Other permanent differences (2)	(2,334	)	1,119		(8,100	)
Total income tax (recovery) expense from continuing operations	$(100,059	)	$127,215		$128,261	
Current income tax expense from continuing operations						
United States	$1,070		$1,260		$1,250	
Foreign	14,313		91,605		155,876	
	15,383		92,865		157,126	
Deferred income tax (recovery) expense from continuing operations						
Foreign (3)	(115,442	)	34,350		(28,865	)
Total income tax (recovery) expense from continuing operations	$(100,059	)	$127,215		$128,261	

(1) Impact of foreign taxes in the rate reconciliation are tax effected at the 35% statutory rate and for the years ended December 31, 2015 and 2014, included $11.8 million and $28.1 million, respectively, in Colombia.

(2) Other permanent differences in the rate reconciliation are tax effected at the 35% statutory rate. For the year ended December 31, 2013, these differences included $7.4 million of tax basis and loss adjustments, $5.0 million of which were offset by changes in the valuation allowance.

(3) The deferred tax recovery for the year ended December 31, 2015, included $91.7 million associated with the ceiling test impairment loss in Colombia.

In the fourth quarter of 2014, Congressional authorities in Colombia and Peru enacted new legislation containing tax rate changes effective January 1, 2015. In Colombia, the CREE tax that was previously introduced as a temporary measure was made permanent and an additional surtax was introduced for 2015 to 2018 fiscal periods, resulting in an increase of the

Colombian deferred tax liability of approximately $31.0 million. Accordingly, the CREE surtax rate during this period will be as follows: 2015: 5%; 2016: 6%; 2017: 8% and 2018: 9%. These increases will result in a consolidated income tax, CREE tax and CREE surtax rate of: 39% for 2015; 40% for 2016; 42% for 2017; and 43% for 2018. Under current legislation, the consolidated rate is set to revert to 34% in 2019 and onwards. In Peru, the legislation contained scheduled reductions to the income tax rate in 2015 through 2019. The tax rates applied to the calculation of deferred income taxes have been adjusted to reflect these changes.

	As at December 31,	
(Thousands of U.S. Dollars)	2015	2014
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	$56,015	$51,248
Tax basis in excess of book basis	139,012	108,120
Foreign tax credits and other accruals	22,674	20,369
Tax benefit of capital loss carryforwards	30,799	29,984
Deferred tax assets before valuation allowance	248,500	209,721
Valuation allowance	(245,259)	(207,568)
	3,241	2,153
Deferred Tax Liabilities	34,592	176,364
Net Deferred Tax Liabilities	$(31,351)	$(174,211)

Undistributed earnings of foreign subsidiaries as of December 31, 2015, were considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

As at December 31, 2015, the Company had operating loss carryforwards of $178.7 million (December 31, 2014 - $167.0 million) and capital loss carryforwards of $228.1 million (December 31, 2014 – $232.2 million) before valuation allowance. Of these operating loss and capital loss carryforwards, $355.9 million (December 31, 2014 - $356.1 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between 2015 and 2035 and the capital loss carryforwards expire between 2016 and 2020, while certain other jurisdictions allow operating and capital losses to be carried forward indefinitely.

The valuation allowance increased by $37.7 million during the year ended December 31, 2015. The change in the valuation allowance was primarily due to impairment losses recorded in Peru and Brazil and an increased corporate tax rate in Canada, partially offset by foreign currency translation adjustments. Also, the Company continues to incur losses in the U.S., Peru, Brazil and Canada. These losses are fully offset by a valuation allowance as their recognition does not meet the “more likely than not” threshold.

As at December 31, 2015, the total amount of Gran Tierra’s unrecognized tax benefit related to continuing operations was $2.2 million (December 31, 2014 - $3.3 million; December 31, 2013 - $2.9 million), which if recognized would affect the Company’s effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations. As at December 31, 2015, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the consolidated balance sheet was approximately $1.4 million (December 31, 2014 - $2.0 million). Interest and penalties on the unrecognized tax benefit included in income tax expense from continuing operations for the year ended December 31, 2015 was a recovery of $0.6 million (2014 - $0.4 million; 2013 - a recovery of $2.1 million). The Company had no other material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2015, respectively.

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

	Year Ended December 31,		
	2015	2014	2013
(Thousands of U.S. Dollars)			
Unrecognized tax benefit relating to loss or income from continuing operations, beginning of year	$3,300	$2,900	$5,900
Increases for positions relating to prior year	—	500	—
Decreases for positions relating to prior year	(800)	(100)	(3,000)
Decreases due to lapse of statute of limitations	(300)	—	—
Unrecognized tax benefit relating to loss or income from continuing operations, end of year	$2,200	$3,300	$2,900

The Company and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for the tax years 2008 through 2015 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

On December 23, 2014, the Colombian Congress passed a law which imposes an equity tax levied on Colombian operations for 2015, 2016 and 2017. The equity tax is calculated based on a legislated measure, which is based on the Company's Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. This measure is subject to adjustment for inflation in future years. The equity tax rates for January 1, 2015, 2016 and 2017, are 1.15%, 1% and 0.4%, respectively. The legal obligation for each year's equity tax liability arises on January 1 of each year; therefore, the Company recognized the annual amount of $3.8 million for the equity tax expense in the consolidated statement of operations for the year ended December 31, 2015. This amount was paid in May and September 2015 and at December 31, 2015, accounts payable included $nil (December 31, 2014 - $nil).

10. Accounts Payable and Accrued Liabilities

	As at December 31,	
(Thousands of U.S. Dollars)	2015	2014
Trade	$54,402	$148,998
Royalties	2,066	10,788
VAT and withholding tax	818	8,573
Employee compensation and severance	8,414	10,900
Other	5,078	8,572
	$70,778	$187,831

11. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

As at December 31, 2015, future minimum payments under non-cancelable agreements with remaining terms in excess of one year were as follows:

	Year ending December 31						
	Total	2016	2017	2018	2019	2020	Thereafter
(Thousands of U.S. Dollars)							
Oil transportation services	$18,441	$3,650	$3,640	$3,640	$3,640	$3,640	$231
Drilling, completions and seismic	7,572	2,918	2,667	1,987	—	—	—
Operating leases	7,140	3,103	2,647	1,389	1	—	—
Software and telecommunication	479	351	128	—	—	—	—
	$33,632	$10,022	$9,082	$7,016	$3,641	$3,640	$231

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for the year ended December 31, 2015, was $4.0 million (year ended December 31, 2014 – $3.2 million; year ended December 31, 2013 - $3.1 million).

Indemnities

Corporate indemnities have been provided by the Company to directors and officers for various items including, but not limited to, all costs to settle suits or actions due to their association with the Company and its subsidiaries and/or affiliates, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The maximum amount of any potential future payment cannot be reasonably estimated. The Company may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

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

Letters of credit

At December 31, 2015, the Company had provided promissory notes totaling $76.5 million (December 31, 2014 - $86.3 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

Contingencies

Gran Tierra's production from the Costayaco Exploitation Area is subject to an additional royalty (the "HPR royalty"), which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Block exploration and production contract (the "Chaza Contract") and the sales price. The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta Fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra's view that, pursuant to the terms of the Chaza Contract, the HPR royalty was only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeded five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. Gran Tierra supplemented its claim on May 30, 2013. The ANH filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty is payable, and that the Chaza Contract be terminated.

Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH's responses to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. On April 30, 2015, total cumulative production from the Moqueta Exploitation Area reached 5.0 MMbbl and Gran Tierra commenced paying the HPR royalty payable on production over that threshold. The estimated compensation which would be payable on cumulative production if the ANH's claims are accepted in the arbitration is $66.3 million plus related interest of $26.5 million. Gran Tierra also disagrees with the interest rate that the ANH has used in calculating the interest cost. Gran Tierra asserts that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum. At December 31, 2015, based on an interest rate of three-month LIBOR plus 4% related interest would be $6.4 million. At this time no amount has been accrued in the consolidated financial statements nor deducted from the Company's reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $44.8 million as at December 31, 2015. At this time no amount has been accrued in the consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

Other gains and losses in the three years ended December 31, 2015, related to a contingent loss accrued in connection with a legal dispute. In 2013, the Company received an adverse legal judgment and the amount awarded in the legal judgment was denominated in bbl of oil. The Company filed an appeal against the judgment. Other gains in the year ended December 31, 2014, related to a reduction in the value of this contingent loss due to lower oil prices. During the three months ended December 31, 2015, the Company received an adverse legal judgment from the appeal court. The Company paid $1.9 million, the amount awarded by the appeal court, during the fourth quarter of 2015 and a gain of $0.5 million was recognized as a result of a reduction in the value of the previously recognized contingent loss.

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

12. Financial Instruments, Fair Value Measurement, Credit Risk and Foreign Exchange Risk

Financial Instruments

At December 31, 2015, the Company’s financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, trading securities, accounts payable, accrued liabilities and contingent consideration included in other long-term liabilities.

Fair Value Measurement

The fair value of the trading securities and contingent consideration are being remeasured at the estimated fair value at each reporting period.

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

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

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

The fair value of the trading securities, foreign currency derivative liability and contingent consideration at December 31, 2015, and December 31, 2014 were as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	2015	2014
Trading securities	$6,250	$7,586
Foreign currency derivative liability	$—	$3,057
Contingent consideration liability	1,061	1,061
	$1,061	$4,118

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

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2015	2014	2013
Trading securities loss	$1,335	$6,326	$—
Foreign currency derivatives loss (gain)	692	(1,604)	—
	$2,027	$4,722	$—

These losses are presented as financial instruments loss in the consolidated statements of operations and cash flows. There were no sales of trading securities in the three years ended December 31, 2015, and the trading securities loss represents an unrealized loss.

The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities.

At December 31, 2015 and December 31, 2014, the fair value of the trading securities acquired in connection with the disposal of the Argentina business unit was determined using Level 1 inputs. At December 31, 2014, the fair value of the foreign currency derivatives was determined using Level 2 inputs. At December 31, 2015, and December 31, 2014, the fair value of the contingent consideration payable in connection with the Brazil acquisition was determined using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of cash and restricted cash is based on Level 1 inputs.

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

Foreign Exchange Risk

Unrealized foreign exchange gains and losses primarily result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, which are monetary liabilities mainly denominated in the local currency of the Colombian operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $10,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

From time to time, the Company purchases non-deliverable forward contracts for purposes of fixing exchange rates at which it will purchase or sell Colombian pesos to settle its income tax installment payments. At December 31, 2015, the Company did not have any open foreign currency derivative positions. With the exception of these foreign currency derivatives, any foreign currency transactions are conducted on a spot basis with major financial institutions in the Company's operating areas.

For the year ended December 31, 2015, 97% (year ended December 31, 2014 - 95%, year ended December 31, 2013 - 96%) of the Company's oil and natural gas sales were generated in Colombia. In Colombia, the Company receives 100% of its revenues in U.S. dollars and the majority of its capital expenditures are in U.S. dollars or are based on U.S. dollar prices. In Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of the Company's capital expenditures within Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. In Peru, capital expenditures are based on U.S. dollar prices and may be paid in local currency or U.S. dollars.

Credit Risk

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

At December 31, 2015, cash and cash equivalents and restricted cash included balances in bank accounts, term deposits and certificates of deposit, placed with financial institutions with strong investment grade ratings or governments.

Most of the Company's accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the year ended December 31, 2015, the Company had four customers which were significant to the Colombian segment, and one customer which was significant to the Brazil segment.

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

13. Severance Expenses

During the year ended December 31, 2015, the Company reduced the number of its employees and contractors. Severance expenses were recorded as incurred based on existing employee contracts, statutory requirements, completed negotiations and company policy. Severance expenses for the Company's reportable segments and other activities for the year ended December 31, 2015, were as follows:

Year Ended December 31, 2015

(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Severance expenses	$1,837	$2,096	$374	$4,683	$8,990

The amounts in the table represent cumulative costs incurred to date and exclude the impact of the reversal of stock-based compensation expense for unvested options of terminated employees which was recorded in G&A expenses. Changes in the severance cost related liability were as follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2015
Balance, December 31, 2014	$—
Liability incurred	8,990
Settlements	(7,526)
Balance, December 31, 2015	$1,464

14. Credit Facility

At December 31, 2015, the Company had a credit facility with a syndicate of lenders. Availability under the credit facility is determined by a proven reserves-based borrowing base, and remains subject to the satisfaction of conditions precedent set forth in the credit agreement. Loans under the credit agreement will mature on September 18, 2018. The initial borrowing base is $200 million and the borrowing base will be re-determined semi-annually based on reserve evaluation reports, subject to a maximum of $500 million. The borrowing base for the credit facility is supported by the present value of the petroleum reserves of two of the Company's subsidiaries with operating branches in Colombia. The credit agreement includes a letter of credit sub-limit of up to $100 million. Amounts drawn down under the facility bear interest, at the Company's option, at the USD LIBOR rate plus a margin ranging from 2.00% and 3.00% per annum, or an alternate base rate plus a margin ranging from 1.00% per annum to 2.00% per annum, in each case based on the borrowing base utilization percentage. Undrawn amounts under the credit facility bear interest at 0.75% per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure. Under the terms of the credit facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. No amounts have been drawn on this facility. This credit facility was entered into and became effective on September 18, 2015, and replaced the Company's previous credit facility which was canceled on this date. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility and, if the Company is not in default, it is required to obtain bank approval for dividend payments to shareholders outside of the credit facility group.

15. Supplemental Cash Flow Information

Net changes in assets and liabilities from operating activities of continuing operations were as follows:

	Year Ended December 31,		
	2015	2014	2013
Accounts receivable and other long-term assets	$44,365	$(34,473)	$58,955
Inventory	(1,571)	(2,891)	14,168
Prepaids	152	4	(2,458)
Accounts payable and accrued and other long-term liabilities	(34,493)	558	(8,754)
Taxes receivable and payable	(48,251)	(61,064)	84,687
Net changes in assets and liabilities from operating activities of continuing operations	$(39,798)	$(97,866)	$146,598

The following table provides additional supplemental cash flow disclosures:

	Year Ended December 31,		
	2015	2014	2013
Cash paid for income taxes	$39,422	$101,179	$51,183
Non-cash investing activities:			
Net liabilities related to property, plant and equipment, end of year	$33,923	$113,874	$75,580
Acquisition of marketable securities as proceeds from sale of Argentina business unit (Note 3)	$—	$13,912	$—

16. Subsequent events

a) On January 13, 2016, (the “Petroamerica Acquisition Date”), the Company acquired all of the issued and outstanding common shares of Petroamerica Oil Corp. ("Petroamerica"), a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated November 12, 2015, (the “Arrangement”). Petroamerica is a Calgary based oil and gas exploration, development and production company active in Colombia. The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petroamerica shareholders and by the Court of Queen's Bench of Alberta on January 11, 2016. Under the Arrangement, Petroamerica shareholders received, for each Petroamerica share held, either 0.40 of a Gran Tierra common share or $1.33 Canadian dollars in cash.

As consideration for the acquisition of all the issued and outstanding Petroamerica shares, the Company issued of 13,656,719 shares of Gran Tierra Common Stock, par value $0.001, and paid cash consideration of $70.6 million. The fair value of Gran Tierra’s Common Stock issued was determined to be $25.8 million based on the closing price of shares of Common Stock of Gran Tierra as at the Petroamerica Acquisition Date. Total net purchase price of Petroamerica was $70.4 million, after giving consideration to estimated net working capital of $26.0 million. Upon completion of the transaction on the Petroamerica Acquisition Date, Petroamerica became an indirect wholly-owned subsidiary of Gran Tierra. Upon the closing of the Arrangement, Petroamerica and Gran Tierra security holders owned approximately 4.6% and 95.4% of Gran Tierra respectively, immediately following the transaction. The total consideration for the transaction was $96.4 million.

b) On January 25, 2016, the Company acquired all of the issued and outstanding common shares of PetroGranada Colombia Limited ("PGC"), pursuant to the terms and conditions of an acquisition agreement dated January 14, 2016. The net purchase price of PGC was $19.0 million, after giving consideration to estimated net working capital of $18.7 million. Contingent consideration of $4.0 million will be payable if cumulative production from the Putumayo-7 Block plus gross proved plus probable reserves under the Putumayo Block meet or exceed 8 MMbbl. PGC is an oil and gas exploration, development and production company active in Colombia. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra.

Due to the limitations on access to Petroamerica and PGC information prior to the closing dates of the acquisitions, and the limited time since the acquisitions closed, the initial accounting for the acquisitions is incomplete at this time. As a result, the Company is unable to disclose amounts recognized as of the acquisition dates for the major classes of assets acquired and liabilities assumed, including the information required for net working capital and goodwill, if any. This information will be included in the Company's first quarter 2016 Quarterly Report on Form 10-Q.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, “Extractive Activities—Oil and Gas,” and regulations of the U.S. Securities and Exchange Commission (SEC), the Company is making certain supplemental disclosures about its oil and gas exploration and production operations.

A. Estimated Proved NAR Reserves

The following table sets forth Gran Tierra's estimated proved NAR reserves and total net proved developed and undeveloped reserves as of December 31, 2012, 2013, 2014 and 2015, and the changes in total net proved reserves during the three-year period ended December 31, 2015.

The net proved reserves represent management’s best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and 100% of the reserves at December 31, 2015, have been evaluated by independent qualified reserves consultants, McDaniel & Associates Consultants Ltd.

The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. The determination of oil and natural gas reserves is complex and requires significant judgment. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. “Risk Factors”. See "Critical Accounting Estimates" in Item 7 for a description of Gran Tierra’s reserves estimation process.

	Colombia Liquids (1) (Mbbl)	Gas (MMcf)	Argentina Liquids (1) (Mbbl)	Gas (MMcf)	Brazil Liquids (1) (Mbbl)	Gas (MMcf)	Total Liquids (1) (Mbbl)	Gas (MMcf)
Proved NAR Reserves, December 31, 2012	31,109	9,472	5,793	3,304	1,591	—	38,493	12,776
Extensions and discoveries	4,625	—	29	1,115	—	—	4,654	1,115
Purchases of reserves in place	—	—	—	—	—	—	—	—
Production	(6,684)	(82)	(887)	(1,338)	(263)	—	(7,834)	(1,420)
Revisions of previous estimates	5,509	(614)	(1,331)	1,596	355	—	4,533	982
Proved NAR Reserves, December 31, 2013	34,559	8,776	3,604	4,677	1,683	—	39,846	13,453
Extensions and discoveries	4,099	—	—	—	572	—	4,671	—
Purchases of reserves in place	—	—	—	—	—	—	—	—
Production	(6,654)	(329)	(385)	(713)	(330)	—	(7,369)	(1,042)
Sales of reserves in place	—	—	(3,219)	(3,964)	—	—	(3,219)	(3,964)
Revisions of previous estimates	2,040	(7,464)	—	—	911	—	2,951	(7,464)
Proved NAR Reserves, December 31, 2014	34,044	983	—	—	2,836	—	36,880	983
Extensions and discoveries	410	526	—	—	—	2,805	410	3,331
Improved recoveries	—	—	—	—	1,396	—	1,396	—
Production	(6,872)	(318)	—	—	(189)	—	(7,061)	(318)
Revisions of previous estimates	5,804	632	—	—	680	—	6,484	632
Proved NAR Reserves, December 31, 2015	33,386	1,823	—	—	4,723	2,805	38,109	4,628
Proved Developed Reserves NAR,	28,598	8,776	2,448	3,750	537	—	31,583	12,526

December 31, 2013								
Proved Developed Reserves NAR, December 31, 2014	27,866	983	—	—	1,333	—	29,199	983
Proved Developed Reserves NAR, December 31, 2015	28,513	1,346	—	—	2,303	1,368	30,816	2,714
Proved Undeveloped Reserves NAR, December 31, 2013	5,961	—	1,156	927	1,146	—	8,263	927
Proved Undeveloped Reserves NAR, December 31, 2014	6,178	—	—	—	1,503	—	7,681	—
Proved Undeveloped Reserves NAR, December 31, 2015	4,873	477	—	—	2,420	1,437	7,293	1,914

(1) At December 31, 2015 and 2014, liquids reserves are 100% oil. At December 31, 2013 and 2012, the Company had NGL reserves in small amounts in Colombia and Argentina only.

B. Capitalized Costs

Capitalized costs for Gran Tierra's oil and gas producing activities consisted of the following at the end of each of the years in the two-year period ended December 31, 2015:

	Proved Properties	Unproved Properties	Accumulated Depletion, Depreciation and Impairment	Net Capitalized Costs
Colombia	$1,846,522	$147,500	$(1,422,617)	$571,405
Brazil	151,808	69,089	(106,124)	114,773
Peru	—	94,182	—	94,182
Balance, December 31, 2015	$1,998,330	$310,771	$(1,528,741)	$780,360
Colombia	$1,736,128	$170,474	$(1,021,809)	$884,793
Brazil	140,243	60,716	(53,487)	147,472
Peru	—	85,666	—	85,666
Balance, December 31, 2014	$1,876,371	$316,856	$(1,075,296)	$1,117,931

C. Costs Incurred

The following tables present costs incurred for Gran Tierra's oil and gas property acquisitions, exploration and development for the respective years:

	Colombia	Argentina (1)	Brazil	Peru	Total
Balance, December 31, 2012	$1,396,429	$256,458	$153,874	$139,130	$1,945,891
Property acquisition costs					
Proved	—	—	—	—	—
Unproved	—	(4,083)	—	—	(4,083)
Exploration costs	41,628	—	26,429	82,275	150,332
Development costs	144,790	22,601	(3,986)	—	163,405
Balance, December 31, 2013	1,582,847	274,976	176,317	221,405	2,255,545
Property acquisition costs					
Proved	—	—	—	—	—
Unproved	—	—	—	—	—
Exploration costs	88,378	82	11,106	173,126	272,692
Development costs	124,307	18,179	12,983	—	155,469
Balance, December 31, 2014	1,795,532	293,237	200,406	394,531	2,683,706
Property acquisition costs					
Proved	—		—	—	—
Unproved	—		—	—	—

Exploration costs	17,512		12,466	50,347	80,325
Development costs	69,910		7,472	—	77,382
Balance, December 31, 2015	$1,882,954	$293,237	$220,344	$444,878	$2,841,413

D. Results of Operations for Oil and Gas Producing Activities

	Colombia	Brazil	Peru	Total Continuing Operations	Argentina	Total
Year Ended December 31, 2015						
Oil and natural gas sales	$269,035	$6,976	$—	$276,011	$—	$276,011
Production costs	(109,406)	(6,363)	—	(115,769)	—	(115,769)
Exploration expenses	—	—	—	—	—	—
DD&A expenses	(167,701)	(6,183)	(789)	(174,673)	—	(174,673)
Asset Impairment	(235,069)	(46,933)	(41,916)	(323,918)		(323,918)
Income tax expense	102,014	(880)	—	101,134	—	101,134
Results of Operations	$(141,127)	$(53,383)	$(42,705)	$(237,215)	$—	$(237,215)
Year Ended December 31, 2014						
Oil and natural gas sales	$532,196	$27,202	$—	$559,398	$31,938	$591,336
Production costs	(107,101)	(6,848)	—	(113,949)	(14,612)	(128,561)
Exploration expenses	—	—	—	—	—	—
DD&A expenses	(174,063)	(9,932)	(690)	(184,685)	(13,684)	(198,369)
Asset Impairment	—	—	(265,126)	(265,126)	—	(265,126)
Income tax expense	(125,171)	(844)	68	(125,947)	(1,458)	(127,405)
Results of Operations	$125,861	$9,578	$(265,748)	$(130,309)	$2,184	$(128,125)
Year Ended December 31, 2013						
Oil and natural gas sales	$624,410	$22,545	$—	$646,955	$73,495	$720,450
Production costs	(102,861)	(7,311)	—	(110,172)	(38,886)	(149,058)
Exploration expenses	—	—	—	—	—	—
DD&A expenses	(184,697)	(14,761)	(362)	(199,820)	(64,295)	(264,115)
Asset Impairment	—	(2,000)	—	(2,000)	—	(2,000)
Income tax expense	(115,546)	(11,091)	(81)	(126,718)	(6,547)	(133,265)
Results of Operations	$221,306	$(12,618)	$(443)	$208,245	$(36,233)	$172,012

E. Standardized Measure of Discounted Future Net Cash Flows and Changes

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions to Gran Tierra's after royalty share of estimated annual future production from proved oil and gas reserves.

	Colombia	Brazil	Argentina
Twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within the twelve month period			
2015	$43.51	$37.72	$—
2014	$87.55	$84.63	$—
2013	$96.49	$90.70	$65.46
Weighted average production costs			
2015	$12.11	$8.30	$—
2014	$14.74	$11.24	$—
2013	$11.89	$20.43	$26.10

Future development and production costs to be incurred in producing and further developing the proved reserves are based on year end cost indicators. Future income taxes are computed by applying year end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows. Discounted future net cash flows are calculated using 10% mid-year discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

The Company believes this information does not in any way reflect the current economic value of its oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period.

The standardized measure of discounted future net cash flows from Gran Tierra's estimated proved oil and gas reserves is as follows:

	Colombia	Argentina	Brazil	Total
December 31, 2015				
Future cash inflows	$1,486,828	$—	$195,726	$1,682,554
Future production costs	(697,071)	—	(58,058)	(755,129)
Future development costs	(51,671)	—	(15,660)	(67,331)
Future asset retirement obligations	(15,096)	—	(1,200)	(16,296)
Future income tax expense	(196,981)	—	(17,361)	(214,342)
Future net cash flows	526,009	—	103,447	629,456
10% discount	(119,100)	—	(45,599)	(164,699)
Standardized Measure of Discounted Future Net Cash Flows	$406,909	$—	$57,848	$464,757
December 31, 2014				
Future cash inflows	$3,020,286	$—	$240,022	$3,260,308
Future production costs	(998,809)	—	(63,928)	(1,062,737)
Future development costs	(182,503)	—	(14,150)	(196,653)
Future asset retirement obligations	(16,410)	—	(3,500)	(19,910)
Future income tax expense	(558,048)	—	(20,554)	(578,602)
Future net cash flows	1,264,516	—	137,890	1,402,406
10% discount	(337,969)	—	(43,304)	(381,273)
Standardized Measure of Discounted Future Net Cash Flows	$926,547	$—	$94,586	$1,021,133
December 31, 2013				
Future cash inflows	$3,518,822	$287,689	$152,692	$3,959,203
Future production costs	(969,644)	(132,184)	(46,489)	(1,148,317)
Future development costs	(194,178)	(45,479)	(10,800)	(250,457)
Future asset retirement obligations	(13,540)	(3,794)	(2,500)	(19,834)
Future income tax expense	(628,628)	(21,929)	—	(650,557)
Future net cash flows	1,712,832	84,303	92,903	1,890,038
10% discount	(489,836)	(29,767)	(25,482)	(545,085)
Standardized Measure of Discounted Future Net Cash Flows	$1,222,996	$54,536	$67,421	$1,344,953

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following table summarizes changes in the standardized measure of discounted future net cash flows for Gran Tierra's proved oil and gas reserves during three years ended December 31, 2015:

	2015	2014	2013
Balance, beginning of year	$1,021,133	$1,344,953	$1,297,452
Sales and transfers of oil and gas produced, net of production costs	(160,242)	(444,358)	(571,391)
Net changes in prices and production costs related to future production	(918,746)	(40,162)	(66,370)
Extensions, discoveries and improved recovery, less related costs	22,754	152,426	239,125
Previously estimated development costs incurred during the year	54,904	107,842	127,255
Revisions of previous quantity estimates	144,603	103,359	262,888
Accretion of discount	137,853	180,787	175,980
Purchases of reserves in place	—	—	—
Sales of reserves in place	—	(72,089)	—
Net change in income taxes	100,587	(256,033)	(26,943)
Changes in future development costs	61,911	(55,592)	(93,043)
Net (decrease) increase	(556,376)	(323,820)	47,501
Balance, end of year	$464,757	$1,021,133	$1,344,953

2) Summarized Quarterly Financial Information

	Three Months Ended				Year Ended
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015	December 31, 2015
Oil and natural gas sales	76,231	69,350	75,653	54,777	276,011
Asset impairment	37,014	30,285	149,979	106,640	323,918
Income (loss) from continuing operations	$(44,866)	$(38,564)	$(101,877)	$(82,722)	$(268,029)
Loss from discontinued operations, net of income taxes	—	—	—	—	—
Net income (loss)	$(44,866)	$(38,564)	$(101,877)	$(82,722)	$(268,029)
Income (loss) per share					
Basic					
Income (loss) from continuing operations	(0.16)	(0.13)	(0.36)	(0.29)	(0.94)
Loss from discontinued operations, net of income taxes	—	—	—	—	—
Net income (loss)	(0.16)	(0.13)	(0.36)	(0.29)	(0.94)
Diluted					
Income (loss) from continuing operations	(0.16)	(0.13)	(0.36)	(0.29)	(0.94)
Loss from discontinued operations, net of income taxes	—	—	—	—	—
Net income (loss)	(0.16)	(0.13)	(0.36)	(0.29)	(0.94)

	Three Months Ended				Year Ended
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014	December 31, 2014
Oil and natural gas sales	151,105	147,888	161,517	98,888	559,398
Asset impairment	—	—	—	265,126	265,126
Income (loss) from continuing operations	49,772	31,484	44,184	(269,789)	(144,349)
Loss from discontinued operations, net of income taxes	(4,643)	(22,347)	—	—	(26,990)
Net income (loss)	45,129	9,137	44,184	(269,789)	(171,339)
Income (loss) per share					
Basic					
Income (loss) from continuing operations	0.18	0.11	0.15	(0.94)	(0.51)
Loss from discontinued operations, net of income taxes	(0.02)	(0.08)	—	—	(0.09)
Net income (loss)	0.16	0.03	0.15	(0.94)	(0.60)
Diluted					
Income (loss) from continuing operations	0.18	0.11	0.15	(0.94)	(0.51)
Loss from discontinued operations, net of income taxes	(0.02)	(0.08)	—	—	(0.09)
Net income (loss)	0.16	0.03	0.15	(0.94)	(0.60)

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as of December 31, 2015, to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting

Gran Tierra's management is responsible for establishing and maintaining adequate internal control over financial reporting for Gran Tierra, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of Gran Tierra's management, including our principal executive and principal financial officers, Gran Tierra conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013 (the "2013 COSO Framework"). Based on this evaluation under the 2013 COSO Framework, management concluded that its internal control over financial reporting was effective as of December 31, 2015. The effectiveness of Gran Tierra's internal control over financial reporting as of December 31, 2015 has been audited by Deloitte LLP, independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

We have audited the internal control over financial reporting of Gran Tierra Energy Inc. and subsidiaries (the "Company") as of December 31, 2015, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) and Canadian generally accepted auditing standards, the consolidated financial statements as of and for the year ended December 31, 2015 of the Company and our report dated February 26, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
February 26, 2016
Calgary, Canada

Item 9B. Other Information

Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

Effective July 1, 2015, Mr. Carlos Monges ceased to be President, Gran Tierra Energy Peru S.R.L. In connection with his termination, Mr. Monges received a net severance payment of $208,382, and Gran Tierra Energy Perus S.R.L. paid for his health policy at a value of $4,000.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required regarding our directors is incorporated herein by reference from the information contained in the section entitled “Proposal 1 - Election of Directors” in our definitive Proxy Statement for the 2016 Annual Meeting of Stockholders (our “Proxy Statement”), a copy of which will be filed with the SEC within 120 days after December 31, 2015. For information with respect to our executive officers, see “Executive Officers of the Registrant” at the end of Part I of this report, following Item 4.

The information required regarding Section 16(a) beneficial ownership reporting compliance is incorporated by reference from the information contained in the section entitled “Section 16(a) Beneficial Ownership Reporting Compliance” in our Proxy Statement.

The information required with respect to procedures by which security holders may recommend nominees to our Board of Directors, the composition of our Audit Committee, and whether we have an “audit committee financial expert”, is incorporated by reference from the information contained in the section entitled “Proposal 1 - Election of Directors” in our Proxy Statement.

Adoption of Code of Ethics

Gran Tierra has adopted a Code of Business Conduct and Ethics (the “Code”) applicable to all of its Board members, employees and executive officers, including its Chief Executive Officer (Principal Executive Officer), and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer). Gran Tierra has made the Code available on its website at www.grantierra.com.

Gran Tierra intends to satisfy the public disclosure requirements regarding (1) any amendments to the Code, or (2) any waivers under the Code given to Gran Tierra’s Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer by posting such information on its website at http://www.grantierra.com/corporate-responsibility.html. There were no amendments to the Code or waivers granted thereunder relating to the Principal Executive Officer, Principal Financial Officer or Principal Accounting Officer during 2015.

Item 11. Executive Compensation

The information required regarding the compensation of our directors and executive officers is incorporated herein by reference from the information contained in the section entitled “Executive Compensation and Related Information” in our Proxy Statement, including under the subheadings “Director Compensation,” “Compensation Committee Report” and “Compensation Committee Interlocks and Insider Participation”.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Security Ownership of Certain Beneficial Owners and Management

The information required regarding security ownership of our 10% or greater stockholders and of our directors and management is incorporated herein by reference from the information contained in the section entitled “Security Ownership of Certain Beneficial Owners and Management” in our Proxy Statement.

The following table provides certain information with respect to securities authorized for issuance under Gran Tierra’s equity compensation plans in effect as of the end of December 31, 2015:

Equity Compensation Plan Information

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [1]	(b) Weighted average exercise price of outstanding options, warrants and rights [2]	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)[3]
Equity compensation plans approved by security holders	13,867,014	4.60	13,498,868
Equity compensation plans not approved by security holders	—	—	—
	13,867,014	4.60	13,498,868

[1] Includes shares reserved to be issued pursuant to stock options and restricted stock units (the latter of which may be settled in cash or in shares of our common stock, at our election) granted pursuant to the 2007 Equity Incentive Plan, which is an amendment and restatement of our 2005 Equity Incentive Plan.

[2] Exercise price is not applicable to restricted stock units and, as such, restricted stock units are excluded from this column.

[3] In accordance with Item 201(d) of Regulation S-K, the figure in this column represents the total number of shares of our common stock remaining available for issuance under our 2007 Equity Incentive Plan as of December 31, 2015, minus the awards reported in column (a), above.Note, pursuant to the terms of the 2007 Equity Incentive Plan, the pool of shares available for grant thereunder is not actually reduced until an award is settled in shares of our common stock (as opposed to reducing the pool at the time of grant). Note further, that the 2007 Equity Incentive Plan provides that the number of shares of our common stock reserved for issuance under the plan shall be reduced by: (i) one share for each share of common stock issued pursuant to a stock option or stock appreciation right and (ii) 1.55 shares for each share of our common stock issued pursuant to an any other type of award granted under the 2007 Equity Incentive Plan that is settled in shares of our common stock. Accordingly, the number of shares available for future awards under the 2007 Equity Incentive Plan may be different than the amount shown in this column.

The only equity compensation plan approved by our stockholders is our 2007 Equity Incentive Plan, which is an amendment and restatement of our 2005 Equity Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required regarding related transactions is incorporated herein by reference from the information contained in the section entitled “Certain Relationships and Related Transactions” and, with respect to director independence, the section entitled “Proposal 1 - Election of Directors”, in our Proxy Statement.

Item 14. Principal Accounting Fees and Services

The information required is incorporated herein by reference from the information contained in the sections entitled “Principal Accountant Fees and Services” and “Pre-Approval Policies and Procedures” in the proposal entitled “Ratification of Selection of Independent Auditors” in our Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

The following documents are included as Part II, Item 8. of this Annual Report on Form 10-K:

(2) Financial Statement Schedules

None.

(3) Exhibits

See the Exhibit Index which follows the signature page of this Annual Report on Form 10-K, which is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GRAN TIERRA ENERGY INC.

Date: February 26, 2016	/s/ Gary Guidry By: Gary Guidry President and Chief Executive Officer, Director (Principal Executive Officer)
Date: February 26, 2016	/s/ Ryan Ellson By: Ryan Ellson Chief Financial Officer (Principal Financial and Accounting Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Gary Guidry and Ryan Ellson, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Name	Title	Date
/s/ Gary Guidry Gary Guidry	President and Chief Executive Officer, Director (Principal Executive Officer)	February 26, 2016
/s/ Ryan Ellson Ryan Ellson	Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2016
/s/ J. Scott Price J. Scott Price	Director	February 26, 2016
/s/ Peter Dey Peter Dey	Director	February 26, 2016
/s/ Evan Hazell Evan Hazell	Director	February 26, 2016
/s/ Robert B. Hodgins Robert B. Hodgins	Director	February 26, 2016
/s/ Ronald Royal Ronald Royal	Director	February 26, 2016
/s/ David P. Smith David P. Smith	Director	February 26, 2016
/s/ Brooke Wade Brooke Wade	Director	February 26, 2016

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1	Arrangement Agreement, dated November 12, 2015, between Gran Tierra Energy Inc. and Petroamerica Oil Corp.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 18, 2015 (SEC File No. 001-34018).
3.1	Amended and Restated Articles of Incorporation.	Incorporated by reference to Exhibit 3.1 to the Annual Report on Form 10-K, filed with the SEC on February 26, 2014 (SEC File No. 001-34018).
3.2	Amended and Restated Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed with the SEC on February 26, 2014 (SEC File No. 001-34018).
4.1	Reference is made to Exhibits 3.1 to 3.2.	
4.2	Details of the Goldstrike Special Voting Share.	Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.3	Goldstrike Exchangeable Share Provisions.	Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005 and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.4	Provisions Attaching to the GTE–Solana Exchangeable Shares.	Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the SEC on October 14, 2008 (SEC File No. 001-34018).
10.1	Voting Exchange and Support Agreement by and between Goldstrike, Inc., 1203647 Alberta Inc., Gran Tierra Goldstrike Inc. and Olympia Trust Company dated as of November 10, 2005.	Incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (SEC File No. 333-111656).
10.2	Voting and Exchange Trust Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Exchangeco Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2008 (SEC File No. 001-34018).
10.3	Support Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Callco ULC and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on November 17, 2008 (SEC File No. 001-34018).
10.4	Amended and Restated 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2012 (SEC File No.

		001-34018).
10.5	Form of Restricted Stock Unit Award Agreement Under the 2007 Equity Incentive Plan *	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2013 (SEC File No. 001-34018).
10.6	Form of Option Agreement Under the 2007 Equity Incentive Plan *	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2013 (SEC File No. 001-34018).
10.7	Form of Indemnity Agreement. *	Incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 2, 2008 (SEC File No. 000-52594).
10.8	Form of Voting Support Agreement	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 18, 2015 (SEC File No. 001-34018).

10.9	2005 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.11 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (SEC File No. 333-111656).
10.10	Executive Employment Agreement, dated November 4, 2008, between Gran Tierra Energy Inc. and Dana Coffield. *	Incorporated by reference to Exhibit 10.58 to the Annual Report on Form 10-K, filed with the SEC on February 27, 2009 (SEC File No. 001-34018).
10.11	Executive Employment Agreement, dated January 20, 2010, between Gran Tierra Energy Inc. and David Hardy. *	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 (SEC File No. 001-34018).
10.12	Amendment to Employment Agreement dated May 2, 2012, between Gran Tierra Energy Inc. and David Hardy. *	Incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.13	Executive Employment Agreement dated May 2, 2012, between Gran Tierra Energy Inc. and James Rozon. *	Incorporated by reference to Exhibit 10.12 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.14	Indefinite Employment Contract, dated August 1, 2009, between Gran Tierra Energy Inc. and Carlos Monges. *	Incorporated by reference to Exhibit 10.76 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2014 (SEC File No. 001-34018).
10.15	Individual Labor Contract, dated September 30, 2011, between Gran Tierra Energy Peru S.R.L. and Carlos Monges. *	Incorporated by reference to Exhibit 10.77 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2014 (SEC File No. 001-34018).
10.16	Addenda to the Individual Labor Contract, dated September 30, 2011, between Gran Tierra Energy Peru S.R.L. and Carlos Monges. *	Incorporated by reference to Exhibit 10.78 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2014 (SEC File No. 001-34018).
10.17	Employment Agreement dated December 14, 2011, between Gran Tierra Energy Peru S.R.L. and Carlos Monges. *	Incorporated by reference to Exhibit 10.79 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2014 (SEC File No. 001-34018).
10.18	Expat Assignment Letter Agreement dated January 10, 2014, between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.80 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2014 (SEC File No. 001-34018).
10.19	Amendment dated April 15, 2014 to Expat Assignment Letter Agreement between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 6, 2014 (SEC File No. 001-34018).
10.20		

	Executive Employment Agreement dated July 31, 2014, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on August 6, 2014 (SEC File No. 001-34018).
10.21	Employment Agreement dated July 31, 2014, between Gran Tierra Energy Colombia Ltd. and Adrián Santiago Coral Pantoja. *	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on August 6, 2014 (SEC File No. 001-34018).
10.22	Executive Employment Agreement dated February 2, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Jeffrey Scott *	Incorporated by reference to Exhibit 10.26 to the Annual Report on Form 10-K, filed with the SEC on March 2, 2015 (SEC File No. 001-34018).
10.23	Amendment to Executive Employment Agreement dated February 19, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 7, 2015 (SEC File No. 001-34018).
10.24	Amendment to Executive Employment Agreement dated May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Jeffrey Scott	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).

10.25	Amendment to Executive Employment Agreement dated May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.26	Amendment to Executive Employment Agreement dated May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and James Rozon	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.27	Amendment to Executive Employment Agreement dated May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and David Hardy	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.28	Form of Indemnity Agreement for use with Directors and Executive Officers	Incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.29	Form of Deferred Stock Unit Award Agreement Under the 2007 Equity Incentive Plan*	Filed herewith.
10.30	Form of Deferred Stock Unit Gran Notice Plan*	Filed herewith.
10.31	Executive Employment Agreement effective May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Gary Guidry	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.32	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Ryan Ellson	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.33	Executive Employment Agreement effective May 11, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Alan Johnson	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.34	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Lawrence West	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.35	Executive Employment Agreement effective May 11, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and James Evans	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.36	2014 Executive Officer Cash Bonus Compensation and 2015 Cash Compensation Arrangements. *	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 25, 2015, with respect to 2014 Cash Bonus Compensation and 2015 Cash Compensation Arrangements (SEC File No.

		001-34018).
10.37	Credit Agreement, dated as of September 18, 2015, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on September 21, 2015 (SEC File No. 001-34018).
10.38	Colombian Participation Agreement, dated as of June 22, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.55 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.39	Amendment No. 1 to Colombian Participation Agreement, dated as of November 1, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.56 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.40	Amendment No. 2 to Colombian Participation Agreement, dated as of July 3, 2008, between Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q/A, filed with the SEC on November 19, 2008 (SEC File No. 001-34018).

10.41	Amendment No. 3 to Participation Agreement, dated as of December 31, 2008, by and among Gran Tierra Energy Colombia, Ltd., Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 7, 2009 (SEC File No. 001-34018).
10.42	Amendment No. 4 dated June 13, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.43	Amendment No. 5 dated February 10, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.44	Amendment No. 6 dated March 1, 2012, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.45	Chaza Block Hydrocarbons Exploration and Exploitation Agreement between Argosy Energy International and the National Hydrocarbons Agency dated June 25, 2005.	Incorporated by reference to Exhibit 10.76 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2013 (SEC File No. 001-34018).
10.46	Addendum No. 1 to the Chaza Block Hydrocarbons Exploration and Exploitation Agreement between Argosy Energy International and the National Hydrocarbons Agency.	Incorporated by reference to Exhibit 10.77 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2013 (SEC File No. 001-34018).
10.47	Settlement Agreement, dated May 7, 2015, between Gran Tierra Energy Inc. and West Face SPV (Cayman) I, L.P.	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
12.1	Statement re: Computation of Ratio of Earnings to Fixed Charges	Filed herewith.
21.1	List of subsidiaries.	Filed herewith.
23.1	Consent of Deloitte LLP.	Filed herewith.
23.2	Consent of McDaniel & Associates Consultants Ltd.	Filed herewith.
24.1	Power of Attorney.	See signature page.
31.1	Certification of Principal Executive Officer.	Filed herewith.
31.2	Certification of Principal Financial Officer.	Filed herewith.

32.1	Section 1350 Certifications.	Furnished herewith.
99.1	Gran Tierra Energy Inc. Reserves Assessment and Evaluation of Oil and Gas Properties Corporate Summary, effective December 31, 2015.	Filed herewith.
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	

+ Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Gran Tierra undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

* Management contract or compensatory plan or arrangement.