GRAN TIERRA ENERGY INC.
Form 10-Q
August 04, 2017

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

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017

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)

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

900, 520 - 3 Avenue SW
Calgary, Alberta Canada T2P 0R3
(Address of principal executive offices, including zip code)
(403) 265-3221
(Registrant's telephone number, including area code)

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

On July 31, 2017, the following number of shares of the registrant’s capital stock were outstanding: 386,741,630 shares of the registrant’s Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 3,228,572 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 4,800,992 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant’s Common Stock.

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Quarterly Period Ended June 30, 2017

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q 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 II, Item 1A “Risk Factors” in our Quarterly Reports on Form 10-Q and in Part I, Item 1A “Risk Factors” in our 2016 Annual Report on Form 10-K. The information included herein is given as of the filing date of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission (“SEC”) and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

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

bbl	barrel	BOE	barrels of oil equivalent
Mbbl	thousand barrels	BOEPD	barrels of oil equivalent per day
Mcf	thousand cubic feet	bopd	barrels of oil per day
NAR	net after royalty		

Sales volumes represent production NAR adjusted for inventory changes. 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." Natural gas liquids ("NGLs") 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.

PART I - Financial Information

Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
OIL AND NATURAL GAS SALES (NOTE 3)	$96,128	$ 71,713	$190,787	$ 129,116
EXPENSES				
Operating	27,208	17,748	51,145	36,815
Transportation	6,492	6,217	13,434	18,545
Depletion, depreciation and accretion (Note 3)	31,644	31,884	58,237	68,796
Asset impairment (Notes 3 and 4)	169	92,843	452	149,741
General and administrative (Note 3)	9,513	7,975	18,225	15,024
Transaction	—	—	—	1,237
Severance	—	281	—	1,299
Equity tax	—	—	1,224	3,051
Foreign exchange loss	3,897	781	2,050	1,566
Financial instruments gain (Note 10)	(1,447)	(1,072)	(6,886)	(227)
Interest expense (Note 5)	3,331	2,201	6,426	2,720
	80,807	158,858	144,307	298,567
LOSS ON SALE OF BRAZIL BUSINESS UNIT (NOTE 4)	(9,076)	—	(9,076)	—
GAIN ON ACQUISITION	—	—	—	11,712
INTEREST INCOME	245	749	653	1,198
INCOME (LOSS) BEFORE INCOME TAXES (NOTE 3)	6,490	(86,396)	38,057	(156,541)
INCOME TAX EXPENSE (RECOVERY)				
Current	1,772	5,778	9,189	7,801
Deferred	11,525	(28,615)	22,904	(55,751)
	13,297	(22,837)	32,093	(47,950)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	$(6,807)	$ (63,559)	$5,964	$ (108,591)
NET INCOME (LOSS) PER SHARE - BASIC AND DILUTED	$(0.02)	$ (0.21)	$0.01	$ (0.37)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	398,585,299	296,565,530	398,795,023	295,188,878
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	398,585,299	296,565,530	398,816,091	295,188,878

(See notes to the condensed consolidated financial statements)

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

	June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents (Note 11)	$53,310	$25,175
Restricted cash and cash equivalents (Notes 7 and 11)	5,844	8,322
Accounts receivable	35,086	45,698
Derivatives (Note 10)	2,424	578
Inventory (Note 4)	7,170	7,766
Taxes receivable	24,934	26,393
Prepaid taxes (Note 2)	—	12,271
Other prepaids	3,084	5,482
Total Current Assets	131,852	131,685
Oil and Gas Properties (using the full cost method of accounting)		
Proved	473,044	412,319
Unproved	610,211	647,774
Total Oil and Gas Properties	1,083,255	1,060,093
Other capital assets	5,485	6,516
Total Property, Plant and Equipment (Notes 3 and 4)	1,088,740	1,066,609
Other Long-Term Assets		
Deferred tax assets (Note 2)	82,671	1,611
Prepaid taxes (Note 2)	—	41,784
Restricted cash and cash equivalents (Notes 7 and 11)	9,897	9,770
Other long-term assets	13,894	13,856
Goodwill (Note 3)	102,581	102,581
Total Other Long-Term Assets	209,043	169,602
Total Assets (Note 3)	$1,429,635	$1,367,896
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$95,937	$107,051
Derivatives (Note 10)	—	3,824
Taxes payable (Note 2)	2,419	38,939
Asset retirement obligation (Note 7)	541	5,215
Total Current Liabilities	98,897	155,029
Long-Term Liabilities		
Long-term debt (Notes 5 and 10)	263,613	197,083
Deferred tax liabilities (Note 2)	32,883	107,230
Asset retirement obligation (Note 7)	41,896	38,142
Other long-term liabilities	11,565	11,425
Total Long-Term Liabilities	349,957	353,880
Contingencies (Note 9)		

Shareholders’ Equity		
Common Stock (Note 6) (386,741,630 and 390,807,194 shares of Common Stock and 8,029,564 and 8,199,894 exchangeable shares, par value $0.001 per share, issued and outstanding as at June 30, 2017, and December 31, 2016, respectively)	10,299	10,303
Additional paid in capital	1,334,014	1,342,656
Deficit	(363,532)	(493,972)
Total Shareholders’ Equity	980,781	858,987
Total Liabilities and Shareholders’ Equity	$1,429,635	$1,367,896

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30,	
	2017	2016
Operating Activities		
Net income (loss)	$5,964	$(108,591)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 3)	58,237	68,796
Asset impairment (Notes 3 and 4)	452	149,741
Deferred tax expense (recovery)	22,904	(55,751)
Stock-based compensation (Note 6)	3,183	3,522
Amortization of debt issuance costs (Note 5)	1,225	629
Cash settlement of restricted share units	(501)	(1,186)
Unrealized foreign exchange loss	1,076	50
Financial instruments gain (Note 10)	(6,886)	(227)
Cash settlement of financial instruments (Note 10)	1,216	47
Cash settlement of asset retirement obligation (Note 7)	(298)	(464)
Loss on sale of Brazil business unit (Note 4)	9,076	—
Gain on acquisition	—	(11,712)
Net change in assets and liabilities from operating activities (Note 11)	(28,112)	(6,630)
Net cash provided by operating activities	67,536	38,224
Investing Activities		
Additions to property, plant and equipment (Note 3)	(104,025)	(44,587)
Additions to property, plant and equipment - property acquisitions (Note 4)	(30,410)	(19,388)
Net proceeds from sale of Brazil business unit (Note 4)	34,481	—
Cash deposit received for letter of credit arrangements upon sale of Brazil business unit (Note 4)	4,700	—
Cash paid for business combinations, net of cash acquired	—	(40,201)
Changes in non-cash investing working capital	(627)	(11,059)
Net cash used in investing activities	(95,881)	(115,235)
Financing Activities		
Proceeds from bank debt, net of issuance costs (Note 5)	98,304	—
Repayment of bank debt (Note 5)	(33,000)	—
Proceeds from issuance of shares of Common Stock, net of issuance costs	—	5,350
Repurchase of shares of Common Stock (Note 6)	(10,000)	—
Proceeds from issuance of Convertible Senior Notes, net of issuance costs (Note 5)	—	108,900
Net cash provided by financing activities	55,304	114,250
Foreign exchange (loss) gain on cash, cash equivalents and restricted cash and cash equivalents	(1,175)	1,946
Net increase in cash, cash equivalents and restricted cash and cash equivalents	25,784	39,185
Cash, cash equivalents and restricted cash and cash equivalents, beginning of period (Note 11)	43,267	148,751
Cash, cash equivalents and restricted cash and cash equivalents, end of period (Note 11)	$69,051	$187,936

Supplemental cash flow disclosures (Note 11)

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30, 2017	Year Ended December 31, 2016
Share Capital		
Balance, beginning of period	$10,303	$10,186
Issuance of Common Stock	—	117
Repurchase of Common Stock (Note 6)	(4)	—
Balance, end of period	10,299	10,303
Additional Paid in Capital		
Balance, beginning of period	1,342,656	1,019,863
Issuance of Common Stock, net of share issuance costs	—	314,425
Exercise of stock options	—	5,347
Stock-based compensation (Note 6)	1,354	3,021
Repurchase of Common Stock (Note 6)	(9,996)	—
Balance, end of period	1,334,014	1,342,656
Deficit		
Balance, beginning of period	(493,972)	(28,407)
Net income (loss)	5,964	(465,565)
Cumulative adjustment for accounting change related to tax reorganizations (Note 2)	124,476	—
Balance, end of period	(363,532)	(493,972)
Total Shareholders' Equity	$980,781	$858,987

(See notes to the condensed consolidated financial statements)

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

1. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the “Company” or “Gran Tierra”), is a publicly traded company focused on oil and natural gas exploration and production in Colombia. The Company also has business activities in Peru and, until June 30, 2017, had business activities in Brazil.

2. Significant Accounting Policies

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

The note disclosure requirements of annual consolidated financial statements provide additional disclosures to that required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements as at and for the year ended December 31, 2016, included in the Company’s 2016 Annual Report on Form 10-K, filed with the SEC on March 1, 2017.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2016 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as noted below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

Recently Adopted Accounting Pronouncements

Simplifying the Measurement of Inventory

In July 2015, the Financial Accounting Standards Board (“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 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The implementation of this update did not materially impact the Company’s consolidated financial position, results of operations or cash flows or disclosure.

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting". This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company elected to continue to estimate the total number of awards for which the requisite service period will not be rendered. The implementation of this update did not impact the Company’s consolidated financial position, results of operations or cash flows or disclosure.

Income Taxes - Intra-Entity Transfers of Assets Other than Inventory

At December 31, 2016, GAAP prohibited the recognition of current and deferred income taxes for intra-entity transfers until an asset leaves the consolidated group, therefore, the current income tax effect of tax reorganizations completed in 2016 was deferred and recognized as prepaid income taxes. At December 31, 2016, the Company's balance sheet included $54.1 million of prepaid income taxes, $12.3 million in current prepaid taxes and $41.8 million in long-term prepaid taxes, and $37.5 million of current income taxes payable relating to tax reorganizations completed in 2016.

In October 2016, the FASB issued ASU 2016-16, "Intra-Entity Transfers of Assets Other than Inventory." This ASU requires companies to recognize the income tax effects of intercompany sales or transfers of assets, other than inventory, in the income statement as income tax expense or benefit in the period the sale or transfer occurs. This ASU is effective for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption was permitted as of the beginning of an annual reporting period. The ASU is required to be applied on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings in the period of adoption. The Company early adopted this ASU on January 1, 2017, and in the three months ending March 31, 2017, wrote off the income tax effects that had been deferred from past intercompany transactions to opening deficit. Prepaid tax of $54.1 million and deferred tax assets of $178.6 million were recorded directly to opening deficit at January 1, 2017. Deferred tax assets recorded upon adoption were assessed for realizability under Accounting Standards Codification ("ASC") 740 "Income Taxes", and, valuation allowances were recognized on those deferred tax assets as necessary on the date of adoption. The adoption of ASU 2016-16 did not have any effect on the Company’s cash flows.

Restricted Cash and Cash Equivalents

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash". ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption was permitted. The Company early adopted this ASU on January 1, 2017, on a retrospective basis to each period presented. The implementation of this ASU did not impact the Company's consolidated financial position or results of operations. For the six months ended June 30, 2016, the net increase in cash, cash equivalents and restricted cash and cash equivalents currently disclosed was $39.2 million, compared with the net increase in cash and cash equivalents of $26.1 million as previously disclosed in the consolidated statement of cash flows prior to the adoption of ASU 2016-18.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, "Clarifying the Definition of a Business". ASU 2017-01 narrows the definition of a business and provides a framework that gives entities a basis for making reasonable judgments about whether a transaction involves an asset or a business. ASU 2017-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption was permitted and the Company adopted this ASU on January 1, 2017. The Company now applies an initial screen for determining whether a transaction involves an asset or a business. When substantially all of the fair value of the gross assets acquired is concentrated in a single identified asset, or group of similar identifiable assets, the set will not be a business and no goodwill or gain on acquisition will be recognized. If the screen is not met, a set cannot be considered a business unless it includes an input and a substantive process that together significantly contribute to the ability to create an output. The Company’s acquisition of the Santana and Nancy Burdine-Maxine oil and gas properties in the six months ended June 30, 2017 was not considered a business under this ASU and therefore not allocated goodwill or gain on acquisition (Note 4).

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, "Simplifying the Test for Goodwill Impairment". ASU 2017-04 eliminates step 2 of the goodwill impairment test. An entity no longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. A goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU 2017-04 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2019. Early adoption is permitted. At June 30, 2017, the Company performed a qualitative assessment of goodwill and, based on this assessment, no impairment of goodwill was identified. The Company did not have to perform step 2 of the goodwill impairment test.

3. 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 and Peru, based on geographic organization. Prior to the sale of the Company's Brazil business unit effective June 30, 2017, (Note 4), Brazil was a reportable segment. The All Other category represents the Company's corporate activities. The Company evaluates reportable segment performance based on income or loss before income taxes.

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

	Three Months Ended June 30, 2017				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$91,905	$ —	$4,223	$ —	$96,128
Depletion, depreciation and accretion	30,130	243	1,050	221	31,644
Asset impairment	—	169	—	—	169
General and administrative expenses	5,229	318	438	3,528	9,513
Income (loss) before income taxes	21,598	(767)	1,849	(16,190)	6,490
Segment capital expenditures	55,436	1,002	1,062	365	57,865

	Three Months Ended June 30, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$69,271	$ —	$2,442	$ —	$71,713
Depletion, depreciation and accretion	30,458	71	1,024	331	31,884
Asset impairment	78,208	483	14,152	—	92,843
General and administrative expenses	4,430	387	241	2,917	7,975
Loss before income taxes	(64,836)	(744)	(14,037)	(6,779)	(86,396)
Segment capital expenditures	14,535	1,102	2,160	610	18,407

	Six Months Ended June 30, 2017				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$182,369	$ —	$8,418	$ —	$190,787
Depletion, depreciation and accretion	55,065	469	2,263	440	58,237
Asset impairment	—	452	—	—	452
General and administrative expenses	10,061	673	743	6,748	18,225
Income (loss) before income taxes	58,742	(1,280)	3,369	(22,774)	38,057
Segment capital expenditures	98,276	2,209	2,811	729	104,025

	Six Months Ended June 30, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$125,571	$ —	$3,545	$ —	$129,116
Depletion, depreciation and accretion	66,194	212	1,742	648	68,796
Asset impairment	133,440	899	15,402	—	149,741
General and administrative expenses	7,695	796	533	6,000	15,024
Loss before income taxes	(137,557)	(1,456)	(15,546)	(1,982)	(156,541)
Segment capital expenditures	36,522	2,369	4,880	816	44,587

	As at June 30, 2017				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$1,015,295	$70,116	$—	$3,329	$1,088,740
Goodwill	102,581	—	—	—	102,581
All other assets	182,723	11,290	—	44,301	238,314
Total Assets	$1,300,599	$81,406	$—	$47,630	$1,429,635

	As at December 31, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$939,947	$68,428	$55,196	$3,038	$1,066,609
Goodwill	102,581	—	—	—	102,581
All other assets	177,393	10,848	1,619	8,846	198,706
Total Assets	$1,219,921	$79,276	$56,815	$11,884	$1,367,896

4. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at June 30, 2017	As at December 31, 2016
Oil and natural gas properties		
Proved	$2,767,842	$2,652,171
Unproved	610,211	647,774
	3,378,053	3,299,945
Other	29,832	29,445
	3,407,885	3,329,390
Accumulated depletion, depreciation and impairment	(2,319,145)	(2,262,781)
	$1,088,740	$1,066,609

Asset impairment for the three and six months ended June 30, 2017, and 2016 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2017	2016	2017	2016
Impairment of oil and gas properties	$169	$92,843	$452	$149,077
Impairment of inventory	—	—	—	664
	$169	$92,843	$452	$149,741

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, adjusted for 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 accordance with GAAP, Gran Tierra used an average Brent price of $51.35 per bbl for the purposes of the June 30, 2017, ceiling test calculations (March 31, 2017 - $49.33; December 31, 2016 - $42.92; June 30, 2016 - $44.48; March 31, 2016 - $48.79; December 31, 2015 - $54.08).

Acquisition of Santana and Nancy Burdine-Maxine Blocks

On April 27, 2017, the Company acquired the Santana and Nancy-Burdine-Maxine Blocks in the Putumayo Basin for cash consideration of $30.4 million. The acquisition was accounted for as an asset acquisition with the consideration paid allocated on a relative fair value basis to the net assets acquired.

The following table shows the allocation of the cost of the acquisition based on the relative fair values of the assets and
liabilities acquired:

(Thousands of U.S. Dollars)	
Cost of asset acquisition:	
Cash	$30,410
Allocation of Consideration Paid:	
Oil and gas properties	
Proved	$24,405
Unproved	8,649
	33,054
Inventory	869
Asset retirement obligation - long-term	(3,513)
	$30,410

Disposition of Brazil Business Unit

On June 30, 2017, the Company, through two of its indirect subsidiaries (the “Selling Subsidiaries”), completed the previously announced disposition of its assets in Brazil. Gran Tierra completed the disposition of its Brazil business unit for a purchase price of $35.0 million which, after certain interim closing adjustments, resulted in cash consideration paid to the Selling Subsidiaries of approximately $38.0 million.

At December 31, 2016, assets and liabilities of the Brazil business unit were as follows:

(Thousands of U.S. Dollars)	As at December 31, 2016
Current assets	$1,634
Property, plant and equipment	55,376
	$57,010
Current liabilities	$(11,590)
Long-term liabilities	(2,297)
	$(13,887)

At June 30, 2016, the net book value of the Brazil business unit was greater than the proceeds received resulting in a $9.1 million loss on sale.

Gran Tierra also received a $4.7 million cash payment from the purchaser reflecting the covenant by the purchaser to finalize the documentation and other arrangements to assume liabilities associated with letter of credit arrangements and the release of Gran Tierra from any liabilities in connection with the same, which payment will be reimbursable to the purchaser once such covenant is discharged.

Inventory

At June 30, 2017, oil and supplies inventories were $4.9 million and $2.3 million, respectively (December 31, 2016 - $6.0 million and $1.8 million, respectively). At June 30, 2017, the Company had 180 Mbbl of oil inventory (December 31, 2016 - 208 Mbbl). In the three and six months ended June 30, 2017, the Company recorded oil inventory impairment of $nil (three and six months ended June 30, 2016 - $nil and $0.7 million, respectively) related to lower oil prices.

5. Debt and Interest Expense

At June 30, 2017, the Company had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. As a result of the semi-annual redetermination, the committed borrowing base was increased from $250 million to $300 million effective June 1, 2017. The next re-determination of the borrowing base is due to occur no later than November 2017. Borrowings under the revolving credit facility will mature on September 18, 2018.

The Company's debt at June 30, 2017, and December 31, 2016, was as follows:

(Thousands of U.S. Dollars)	As at June 30, 2017	As at December 31, 2016
Convertible senior notes	$115,000	$115,000
Revolving credit facility	155,000	90,000
Unamortized debt issuance costs	(6,387)	(7,917)
Long-term debt	$263,613	$197,083

The following table presents total interest expense recognized in the accompanying interim unaudited condensed consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2017	2016	2017	2016
Contractual interest and other financing expenses	$2,711	$1,712	$5,201	$2,091
Amortization of debt issuance costs	620	489	1,225	629
	$3,331	$2,201	$6,426	$2,720

6. Share Capital

The Company’s authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as Common Stock, par value $0.001 per share, 25 million are designated as Preferred Stock, par value $0.001 per share, one share is designated as Special A Voting Stock, par value $0.001 per share, and one share is designated as Special B Voting Stock, par value $0.001 per share.

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.

Balance, December 31, 2016	390,807,194	4,812,592	3,387,302
Shares repurchased and canceled	(4,235,890)	—	—
Exchange of exchangeable shares	170,330	(11,600)	(158,730)
Shares canceled	(4)	—	—
Balance, June 30, 2017	386,741,630	4,800,992	3,228,572

On February 6, 2017, the Company announced that it intended to implement a new share repurchase program (the “2017 Program”) through the facilities of the Toronto Stock Exchange ("TSX"), the NYSE American and eligible alternative trading platforms in Canada and the United States. Under the 2017 Program, the Company is able to purchase at prevailing market

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prices up to 19,540,359 shares of Common Stock, representing 5.0% of the issued and outstanding shares of Common Stock as of January 27, 2017. Shares purchased pursuant to the 2017 Program will be canceled. The 2017 Program will expire on February 7, 2018, or earlier if the 5.0% share maximum is reached.

Equity Compensation Awards

The following table provides information about performance stock units ("PSUs"), deferred share units ("DSUs"), restricted stock units ("RSUs") and stock option activity for the six months ended June 30, 2017:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Stock Options	Weighted Average Exercise Price/Stock Option ($)
Balance, December 31, 2016	3,362,717	208,698	359,145	9,239,478	4.16
Granted	3,098,100	104,112	—	1,832,975	2.57
Exercised	—	—	(202,280)	—	—
Forfeited	(274,228)	—	(9,402)	(208,438)	(3.01)
Expired	—	—	—	(1,396,667)	(4.65)
Balance, June 30, 2017	6,186,589	312,810	147,463	9,467,348	3.81

Stock-based compensation expense for the three and six months ended June 30, 2017, was $2.0 million and $3.2 million, respectively, and was primarily recorded in general and administrative ("G&A") expenses (three and six months ended June 30 2016: $2.1 million and $3.5 million, respectively).

At June 30, 2017, there was $13.3 million (December 31, 2016 - $10.0 million) of unrecognized compensation cost related to unvested PSUs, RSUs and stock options which is expected to be recognized over a weighted average period of 1.9 years.

Net Income (Loss) per Share

Basic net income (loss) per share is calculated by dividing net income (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 (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.

Weighted Average Shares Outstanding

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Weighted average number of common and exchangeable shares outstanding	398,585,290	296,565,530	398,795,023	295,188,878

Shares issuable pursuant to stock options	—	—	625,631	—
Shares assumed to be purchased from proceeds of stock options	—	—	(604,563)	—
Weighted average number of diluted common and exchangeable shares outstanding	398,585,290	296,565,530	398,816,091	295,188,878

For the three months ended June 30, 2017, 10,634,157 options, on a weighted average basis, (three months ended June 30, 2016 - 11,738,731 options) were excluded from the diluted income (loss) per share calculation as the options were anti-dilutive. For the six months ended June 30, 2017, 9,616,800 options, on a weighted average basis, (six months ended June 30, 2016 - 12,203,246 options) were excluded from the diluted income (loss) per share calculation as the options were anti-dilutive.

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Shares issuable upon conversion of the Convertible Senior Notes ("Notes") were anti-dilutive and excluded from the diluted income (loss) per share calculation.

7. Asset Retirement Obligation

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

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2017	Year Ended December 31, 2016
Balance, beginning of period	$43,357	$ 33,224
Liability incurred	1,573	2,606
Liabilities assumed in acquisition	3,513	15,723
Accretion	1,686	2,789
Settlements	(466)	(872)
Liabilities associated with assets sold	(2,200)	(3,257)
Revisions in estimated liability	(5,026)	(6,856)
Balance, end of period	$42,437	$ 43,357
Asset retirement obligation - current	$541	$ 5,215
Asset retirement obligation - long-term	41,896	38,142
	$42,437	$ 43,357

For the six months ended June 30, 2017, settlements included $0.3 million cash payments with the balance in accounts payable and accrued liabilities at June 30, 2017. 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 asset retirement obligations. At June 30, 2017, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was $12.3 million (December 31, 2016 - $12.0 million). These assets are accounted for as restricted cash and cash equivalents on the Company's interim unaudited condensed consolidated balance sheets.

8. Taxes

The Company's effective tax rate was 84% in the six months ended June 30, 2017, compared with 31% in the corresponding period in 2016. The Company's effective tax rate differed from the U.S. statutory rate of 35% primarily due to the impact of foreign taxes, other permanent differences, the valuation allowance, which was largely attributable to losses incurred in the United States and Colombia, the non-deductible third-party royalty in Colombia, stock based compensation and other local taxes. These items were partially offset by foreign currency translation adjustments.

9. Contingencies

The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH") and Gran Tierra are engaged in ongoing discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of an additional royalty (the "HPR royalty"). 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 $49.2 million as at June 30, 2017. At this time no amount has been accrued in the interim unaudited condensed consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

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

Letters of credit and other credit support

At June 30, 2017, the Company had provided letters of credit and other credit support totaling $74.5 million (December 31, 2016 - $96.8 million) as security relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

10. Financial Instruments and Fair Value Measurement

Financial Instruments

At June 30, 2017, the Company's financial instruments recognized in the balance sheet consist of: cash and cash equivalents; restricted cash and cash equivalents; accounts receivable; derivatives, accounts payable and accrued liabilities, long-term debt, PSU liability included in other long-term liabilities, and RSU liability included in accounts payable and accrued liabilities and other long-term liabilities.

Fair Value Measurement

The fair value of derivatives and RSU and PSU liabilities are being remeasured at the estimated fair value at the end of each reporting period.

The fair value of commodity price and foreign currency derivatives is estimated based on various factors, including quoted market prices in active markets and quotes from third parties. The Company also performs an internal valuation to ensure the reasonableness of third party quotes. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

The fair value of the RSU liability was estimated based on quoted market prices in an active market. The fair value of the PSU liability was estimated based on quoted market prices in an active market and an option pricing model such as the Monte Carlo simulation option-pricing models.

The fair value of derivatives and RSU, PSU and DSU liabilities at June 30, 2017, and December 31, 2016, were as follows:

(Thousands of U.S. Dollars)	As at June 30, 2017	As at December 31, 2016
Commodity price derivative asset	$2,424	$ —
Foreign currency derivative asset	—	578
	$2,424	$ 578
Commodity price derivative liability	$—	$ 3,824
RSU, PSU and DSU liability	5,528	3,907
	$5,528	$ 7,731

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2017	2016	2017	2016
Commodity price derivative gain	$(1,545)	$(1,334)	$(6,247)	$(1,334)
Foreign currency derivatives loss (gain)	98	(1,118)	(639)	(1,118)
Trading securities loss	—	1,380	—	2,225
Financial instruments gain	$(1,447)	$(1,072)	$(6,886)	$(227)

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

Financial instruments not recorded at fair value include the Notes. At June 30, 2017, the carrying amount of the Notes was $110.4 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was $120.7 million. The fair value of long-term restricted cash and cash equivalents and the revolving credit facility approximated their carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

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

At June 30, 2017, the fair value of the derivatives was determined using Level 2 inputs and the fair value of the PSU liability was determined using Level 3 inputs.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company’s default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company’s Notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The disclosure in the paragraph above regarding the fair value of the Company’s revolving credit facility was determined using an income approach using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of the Notes was determined using Level 2 inputs based on the indicative pricing published by certain investment banks or trading levels of the Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and cash equivalents and restricted cash and cash equivalents was 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.

Commodity Price Derivatives

The Company utilizes commodity price derivatives to manage the variability in cash flows associated with the forecasted sale of its oil production, reduce commodity price risk and provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

At June 30, 2017, the Company had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold Put	Purchased Put	Sold Call

			($/bbl)	($/bbl)	($/bbl)
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65

Foreign Currency Derivatives

The Company utilizes foreign currency derivatives to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("COP") denominated costs. At June 30, 2017, the Company had no outstanding foreign currency derivative positions. Subsequent to the end of the quarter, the Company entered into the following foreign currency contracts:

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged [(1)] (Thousands of U.S. Dollars)	Reference	Purchased Call (COP)	Sold Put (COP, Weighted Average Rate)
Collar: July 1, 2017 to July 31, 2017	5,000	1,646	COP	3,000	3,138
Collar: August 1, 2017 to August 31, 2017	23,000	7,570	COP	3,000	3,116
Collar: September 1, 2017 to September 29, 2017	23,000	7,570	COP	3,000	3,105
Collar: October 1, 2017 to October 31, 2017	23,000	7,570	COP	3,000	3,117
Collar: November 1, 2017 to November 30, 2017	25,000	8,228	COP	3,000	3,139
Collar: December 1, 2017 to December 28, 2017	25,000	8,228	COP	3,000	3,142
	124,000	40,812			

[(1)] At June 30, 2017 foreign exchange rate.

11. Supplemental Cash Flow Information

The following table provides a reconciliation of cash, cash equivalents and restricted cash and cash equivalents with the Company's interim unaudited condensed consolidated balance sheet that sum to the total of the same such amounts shown in the interim unaudited condensed consolidated statements of cash flows:

(Thousands of U.S. Dollars)	As at June 30,		As at December 31	
	2017	2016	2016	2015
Cash and cash equivalents	$53,310	$171,470	$25,175	$145,342
Restricted cash and cash equivalents - current	5,844	9,716	8,322	92
Restricted cash and cash equivalents - long-term	9,897	6,750	9,770	3,317
	$69,051	$187,936	$43,267	$148,751

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

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2017	2016
Accounts receivable and other long-term assets	$11,024	$(9,156)
Derivatives	—	(4,562)
Inventory	(47)	4,365
Prepaids	2,190	1,102
Accounts payable and accrued and other long-term liabilities	(6,179)	(5,628)
Taxes receivable and payable	(35,100)	7,249

Net changes in assets and liabilities from operating activities	$(28,112)	$(6,630)

The following table provides additional supplemental cash flow disclosures:

	Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2017	2016
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	$56,044	$24,497

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

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language at the very beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well as Part II, Item 1A “Risk Factors” in this Quarterly Report on Form 10-Q and Part I, Item 1A “Risk Factors” in our 2016 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" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management’s Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our Annual Report on Form 10-K, filed with the SEC on March 1, 2017.

Highlights

Brazil Divestiture

On June 30, 2017, we completed the disposition of our business unit in Brazil, including our 100% working interest in the Tie Field and all of our interest in exploration rights and obligations held pursuant to concession agreements granted by the ANP. We completed the disposition of our Brazil business unit for a purchase price of $35.0 million which, after certain interim closing adjustments, resulted in cash consideration of approximately $38.0 million.

Acquisition of the Santana and Nancy-Burdine-Maxine Blocks

On April 27, 2017, we acquired the Santana and Nancy-Burdine-Maxine Blocks for cash consideration of $30.4 million. These two blocks were offered by Ecopetrol as part of an asset disposition process and are located in the Putumayo Basin.

Financial and Operational Highlights

	Three Months Ended March 31,	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2017	2016	% Change	2017	2016	% Change
Average Daily Volumes (BOEPD)							
Working Interest Production Before Royalties	29,879	31,437	25,744	22	30,663	25,677	19
Royalties	(5,089)	(5,014)	(4,049)	24	(5,051)	(3,435)	47
Production NAR	24,790	26,423	21,695	22	25,612	22,242	15
(Increase) Decrease in Inventory	18	(140)	723	(119)	(61)	1,682	(104)
Sales[1]	24,808	26,283	22,418	17	25,551	23,924	7
Net Income (Loss) ($000s)	$12,771	$(6,807)	$(63,559)	89	$5,964	$(108,591)	105
Operating Netback ($000s)							
Oil and Natural Gas Sales	$94,659	$96,128	$71,713	34	$190,787	$129,116	48
Operating Expenses	(23,937)	(27,208)	(17,748)	53	(51,145)	(36,815)	39
Transportation Expenses	(6,942)	(6,492)	(6,217)	4	(13,434)	(18,545)	(28)
Operating Netback[2]	$63,780	$62,428	$47,748	31	$126,208	$73,756	71
General and Administrative Expenses ("G&A") ($000s)							
G&A Expenses Before Stock-Based Compensation, Gross	$15,845	$15,933	$14,769	8	$31,778	$27,097	17
Stock-Based Compensation	1,149	1,903	1,988	(4)	3,052	3,386	(10)
Capitalized G&A and Overhead Recoveries	(8,282)	(8,323)	(8,782)	(5)	(16,605)	(15,459)	7
G&A Expenses, Including Stock-Based Compensation ($000s)	$8,712	$9,513	$7,975	19	$18,225	$15,024	21
EBITDA ($000s)[3]	$61,538	$41,634	$40,532	3	$103,172	$64,716	59
Funds Flow From Operations ($000s)[4]	$45,026	$50,920	$33,755	51	$95,946	$45,318	112
Capital Expenditures ($000s)	$46,160	$57,865	$18,407	214	$104,025	$44,587	133

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(Thousands of U.S. Dollars)	As at June 30, 2017	December 31, 2016	% Change
Cash, Cash Equivalents and Current Restricted Cash and Cash Equivalents	$59,154	$ 33,497	77
Revolving Credit Facility	$155,000	$ 90,000	72
Convertible Senior Notes	$115,000	$ 115,000	—

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

Non-GAAP measures

Operating netback, EBITDA, and funds flow from operations are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Management views these measures as financial performance measures. Investors are cautioned that these measures should not be construed as alternatives to net loss or other measures of financial performance or liquidity 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. Each non-GAAP financial measure is presented along with the corresponding GAAP measure so as not to imply that more emphasis should be placed on the non-GAAP measure.

(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 financial performance and provides 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 depletion, depreciation and accretion ("DD&A") expenses, asset impairment, interest expense and income tax recovery or expense. 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 is as follows:

	Three Months Ended March 31,	Three Months Ended June 30,		Six Months Ended June 30,	
EBITDA - Non-GAAP Measure ($000s)	2017	2017	2016	2017	2016
Net income (loss)	$12,771	$(6,807)	$(63,559)	$5,964	$(108,591)
Adjustments to reconcile net income (loss) to EBITDA					
DD&A expenses	26,593	31,644	31,884	58,237	68,796
Asset impairment	283	169	92,843	452	149,741
Interest expense	3,095	3,331	2,201	6,426	2,720
Income tax expense (recovery)	18,796	13,297	(22,837)	32,093	(47,950)
EBITDA	$61,538	$41,634	$40,532	$103,172	$64,716

(4) Funds flow from operations, as presented, is net income or loss adjusted for DD&A expenses, asset impairment, deferred tax expense or recovery, stock-based compensation, amortization of debt issuance costs, cash settlement of

RSUs, unrealized foreign exchange gains and losses, financial instruments gains, cash settlement of financial instruments, loss on sale of Brazil business unit and gain on acquisition.. 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 operations is as follows:

Funds Flow From Operations - Non-GAAP Measure ($000s)	Three Months Ended March 31, 2017	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net income (loss)	$12,771	$(6,807)	$(63,559)	5,964	$(108,591)
Adjustments to reconcile net income (loss) to funds flow from operations					
DD&A expenses	26,593	31,644	31,884	58,237	68,796
Asset impairment	283	169	92,843	452	149,741
Deferred tax expense (recovery)	11,379	11,525	(28,615)	22,904	(55,751)
Stock-based compensation expense	1,203	1,980	2,062	3,183	3,522
Amortization of debt issuance costs	605	620	489	1,225	629
Cash settlement of RSUs	(318)	(183)	(513)	(501)	(1,186)
Unrealized foreign exchange (gain) loss	(2,819)	3,895	233	1,076	50
Financial instruments gain	(5,439)	(1,447)	(1,072)	(6,886)	(227)
Cash settlement of financial instruments	768	448	3	1,216	47
Loss on sale of Brazil business unit	—	9,076	—	9,076	—
Gain on acquisition	—	—	—	—	(11,712)
Funds flow from operations	$45,026	$50,920	$33,755	$95,946	$45,318

Consolidated Results of Operations

	Three Months Ended March 31,	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2017	2016	% Change	2017	2016	% Change
(Thousands of U.S. Dollars)							
Oil and natural gas sales	$94,659	$96,128	$71,713	34	$190,787	$129,116	48
Operating expenses	23,937	27,208	17,748	53	51,145	36,815	39
Transportation expenses	6,942	6,492	6,217	4	13,434	18,545	(28)
Operating netback[(1)]	63,780	62,428	47,748	31	126,208	73,756	71
DD&A expenses	26,593	31,644	31,884	(1)	58,237	68,796	(15)
Asset impairment	283	169	92,843	(100)	452	149,741	(100)
G&A expenses before stock-based compensation	7,563	7,610	5,987	27	15,173	11,638	30
Stock-based compensation expense	1,149	1,903	1,988	(4)	3,052	3,386	(10)
Transaction expenses	—	—	—	—	—	1,237	(100)
Severance expenses	—	—	281	(100)	—	1,299	(100)
Equity tax	1,224	—	—	—	1,224	3,051	(60)
Foreign exchange (gain) loss	(1,847)	3,897	781	399	2,050	1,566	31
Financial instruments gain	(5,439)	(1,447)	(1,072)	(35)	(6,886)	(227)	—
Interest expense	3,095	3,331	2,201	51	6,426	2,720	136
	32,621	47,107	134,893	(65)	79,728	243,207	(67)
Loss on sale of Brazil business unit	—	(9,076)	—	—	(9,076)	—	—
Gain on acquisition	—	—	—	—	—	11,712	(100)
Interest income	408	245	749	(67)	653	1,198	(45)
Income (loss) before income taxes	31,567	6,490	(86,396)	108	38,057	(156,541)	124
Current income tax expense	7,417	1,772	5,778	(69)	9,189	7,801	18
Deferred income tax expense (recovery)	11,379	11,525	(28,615)	140	22,904	(55,751)	141
	18,796	13,297	(22,837)	158	32,093	(47,950)	167
Net income (loss)	$12,771	$(6,807)	$(63,559)	89	$5,964	$(108,591)	105
Sales Volumes							
Total sales volumes, BOEPD	24,808	26,283	22,418	17	25,551	23,924	7
Average Prices							
Oil and NGL's per bbl	$42.96	$40.44	$35.31	15	$41.65	$29.77	40
Natural gas per Mcf	$1.52	$2.52	$3.06	(18)	$1.91	$2.94	(35)
Brent Price per bbl	$54.66	$50.92	$45.52	12	$52.79	$39.61	33

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Consolidated Results of Operations per BOE Sales Volumes NAR							
Oil and natural gas sales	$42.40	$40.19	$35.15	14	$41.25	$29.65	39
Operating expenses	10.72	11.38	8.70	31	11.06	8.46	31
Transportation expenses	3.11	2.71	3.05	(11)	2.90	4.26	(32)
Operating netback[1]	28.57	26.10	23.40	12	27.29	16.93	61
DD&A expenses	11.91	13.23	15.63	(15)	12.59	15.80	(20)
Asset impairment	0.13	0.07	45.51	(100)	0.10	34.39	(100)
G&A expenses before stock-based compensation	3.39	3.18	2.94	8	3.28	2.67	23
Stock-based compensation expense	0.51	0.80	0.97	(18)	0.66	0.78	(15)
Transaction expenses	—	—	—	—	—	0.28	(100)
Severance expenses	—	—	0.14	(100)	—	0.30	(100)
Equity tax	0.55	—	—	—	0.26	0.70	(63)
Foreign exchange (gain) loss	(0.83)	1.63	0.38	(329)	0.44	0.36	(22)
Financial instruments gain	(2.44)	(0.60)	(0.53)	(13)	(1.49)	(0.05)	—
Interest expense	1.39	1.39	1.08	29	1.39	0.62	124
	14.61	19.70	66.13	(70)	17.23	55.85	(69)
Loss on sale of Brazil business unit	—	(3.79)	—	—	(1.96)	—	—
Gain on acquisition	—	—	—	—	—	2.69	(100)
Interest income	0.18	0.10	0.37	(73)	0.14	0.28	(50)
Income (loss) before income taxes	14.14	2.71	(42.36)	106	8.24	(35.95)	123
Current income tax expense	3.32	0.74	2.83	(74)	1.99	1.79	11
Deferred income tax expense (recovery)	5.10	4.82	(14.03)	134	4.95	(12.80)	139
	8.42	5.56	(11.20)	150	6.94	(11.01)	163
Net income (loss)	$5.72	$(2.85)	$(31.16)	91	$1.30	$(24.94)	105

[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.

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Oil and Gas Production and Sales Volumes, BOEPD

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016		
Average Daily Volumes (BOEPD)	Colombia	Brazil	Total	Colombia	Brazil	Total
Working Interest Production Before Royalties	30,098	1,339	31,437	24,818	926	25,744
Royalties	(4,819)	(195)	(5,014)	(3,921)	(128)	(4,049)
Production NAR	25,279	1,144	26,423	20,897	798	21,695
(Increase) Decrease in Inventory	(147)	7	(140)	713	10	723
Sales	25,132	1,151	26,283	21,610	808	22,418
Royalties, % of Working Interest Production Before Royalties	16 %	15 %	16 %	16 %	14 %	16 %

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016		
Average Daily Volumes (BOEPD)	Colombia	Brazil	Total	Colombia	Brazil	Total
Working Interest Production Before Royalties	29,294	1,369	30,663	24,852	825	25,677
Royalties	(4,843)	(208)	(5,051)	(3,298)	(137)	(3,435)
Production NAR	24,451	1,161	25,612	21,554	688	22,242
(Increase) Decrease in Inventory	(70)	9	(61)	1,680	2	1,682
Sales	24,381	1,170	25,551	23,234	690	23,924
Royalties, % of Working Interest Production Before Royalties	17 %	15 %	16 %	13 %	17 %	13 %

Oil and gas production NAR for the three and six months ended June 30, 2017, increased by 22% to 26,423 and 15% to 25,612 BOEPD, respectively, compared with 21,695 and 22,242 BOEPD respectively, in the comparable periods in 2016. In the three and six months ended June 30, 2017, production increased primarily due to the PetroLatina acquisition and a successful drilling campaign in the Acordionero Field in Colombia. The acquisition of PetroLatina Energy Limited closed on August 23, 2016, at which time the Acordionero field was producing approximately 4,730 bopd before royalties. After a successful drilling campaign, production averaged 8,362 bopd before royalties during the three months ended June 30, 2017.

Royalties as a percentage of production for the three months ended June 30, 2017 were consistent with the comparable period in the prior year. For the six months ended June 30, 2017, royalties as a percentage of production increased compared with the comparable period in the prior year commensurate with the increase in oil prices.

Oil and gas production NAR for the three months ended June 30, 2017, increased 7% compared with the prior quarter as a result of a successful drilling and workover campaign in the Costayaco, Moqueta and Acordionero Fields in Colombia.

Oil and gas sales volumes for the three months ended June 30, 2017, increased by 17% to 26,283 BOEPD compared with 22,418 BOEPD in the corresponding period in 2016. Higher working interest production (5,693 BOEPD) more than offset the combination of higher royalty volumes (965 BOEPD) and inventory increases (863 BOEPD). During the three months ended June 30, 2017, oil inventory increases accounted for 140 bopd of reduced sales volumes compared with oil inventory decreases in the corresponding period in 2016, which accounted for 723 bopd of increased sales volumes.

For the six months ended June 30, 2017, oil and gas sales volumes increased by 7% to 25,551 BOEPD compared with 23,924 BOEPD in the corresponding period in 2016. Higher working interest production (4,986 BOEPD) more than offset the combination of higher royalty volumes (1,616 BOEPD) and inventory increases (1,743 BOEPD). During the six months ended June 30, 2017, oil inventory increases accounted for 61 bopd of reduced sales volumes compared with oil inventory decreases in the corresponding period in 2016, which accounted for 1,682 bopd of increased sales volumes.

Oil and gas sales volumes for the three months ended June 30, 2017, increased by 6% to 26,283 BOEPD compared with 24,808 BOEPD in the prior quarter. Sales volumes increased due to higher working interest production (1,558 BOEPD) and lower royalty volumes (75 BOEPD), partially offset by the effect of inventory increases (158 BOEPD).

Operating Netbacks

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016		
(Thousands of U.S. Dollars)	Colombia	Brazil	Total	Colombia	Brazil	Total
Oil and Gas Sales	$91,905	$4,223	$96,128	$69,271	$2,442	$71,713
Transportation Expenses	(6,319)	(173)	(6,492)	(6,105)	(112)	(6,217)
	85,586	4,050	89,636	63,166	2,330	65,496
Operating Expenses	(26,192)	(1,016)	(27,208)	(16,994)	(754)	(17,748)
Operating Netback(1)	$59,394	$3,034	$62,428	$46,172	$1,576	$47,748
U.S. Dollars Per BOE						
Brent	$50.92	$50.92	$50.92	$45.52	$45.52	$45.52
Quality and Transportation Discounts	(10.74)	(10.62)	(10.73)	(10.29)	(12.32)	(10.37)
Average Realized Price	$40.18	$40.30	$40.19	$35.23	$33.20	$35.15
Transportation Expenses	(2.76)	(1.65)	(2.71)	(3.10)	(1.52)	(3.05)
Average Realized Price Net of Transportation Expenses	37.42	38.65	37.48	32.13	31.68	32.10
Operating Expenses	(11.45)	(9.69)	(11.38)	(8.64)	(10.25)	(8.70)
Operating Netback(1)	$25.97	$28.96	$26.10	$23.49	$21.43	$23.40

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016		
(Thousands of U.S. Dollars)	Colombia	Brazil	Total	Colombia	Brazil	Total
Oil and Natural Gas Sales	$182,369	$8,418	$190,787	$125,571	$3,545	$129,116
Transportation Expenses	(13,084)	(350)	(13,434)	(18,361)	(184)	(18,545)
	169,285	8,068	177,353	107,210	3,361	110,571
Operating Expenses	(49,348)	(1,797)	(51,145)	(36,158)	(657)	(36,815)
Operating Netback(1)	$119,937	$6,271	$126,208	$71,052	$2,704	$73,756
U.S. Dollars Per BOE Sales Volumes NAR						
Brent	$52.79	$52.79	$52.79	$39.61	$39.61	$39.61
Quality and Transportation Discounts	(11.46)	(13.03)	(11.54)	(9.91)	(11.42)	(9.96)
Average Realized Price	41.33	39.76	41.25	29.70	28.19	29.65
Transportation Expenses	(2.96)	(1.65)	(2.90)	(4.34)	(1.46)	(4.26)
Average Realized Price Net of Transportation Expenses	38.37	38.11	38.35	25.36	26.73	25.39
Operating Expenses	(11.18)	(8.49)	(11.06)	(8.55)	(5.22)	(8.46)
Operating Netback(1)	$27.19	$29.62	$27.29	$16.81	$21.51	$16.93

(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 three and six months ended June 30, 2017, increased by 34% to $96.1 million and by 48% to $190.8 million, respectively, from $71.7 million and $129.1 million, respectively, in the comparable periods in 2016 due to increased volumes and realized oil prices.

The following table shows the effect of changes in realized prices and sales volumes on our oil and gas sales for the three and six months ended June 30, 2017:

	Second Quarter 2017 Compared with First Quarter 2017	Second Quarter 2017 Compared with Second Quarter 2016	Six Months Ended, June 30, 2017 Compared with Six Months Ended June 30, 2016
Oil and natural gas sales for the comparative period	$ 94,659	$ 71,713	$ 129,116
Realized sales price (decrease) increase effect	(5,278)	12,049	53,654
Sales volume increase effect	6,747	12,366	8,017
Oil and natural gas sales for period ended June 30, 2017	$ 96,128	$ 96,128	$ 190,787

Average realized prices for the three and six months ended June 30, 2017, increased by 14% and 39%, respectively, commensurate with the increase in benchmark oil prices. Average Brent oil prices for the three and six months ended June 30, 2017, increased by 12% and 33% respectively.

Oil and gas sales for the three months ended June 30, 2017, increased by 2% to $96.1 million from $94.7 million compared with the prior quarter primarily due to higher sales volumes partially offset by decreased realized oil prices. Average realized prices decreased by 5% to $40.19 per BOE for the three months ended June 30, 2017, compared with $42.40 per BOE in the prior quarter. Average Brent oil prices for the three months ended June 30, 2017, decreased by 7% to $50.92 per bbl, compared with $54.66 per bbl in the prior quarter. Benchmark global oil prices fell in the three months ending June 30, 2017 compared with the prior quarter, despite certain members of the Organization of Petroleum Exporting Countries (“OPEC“) and non-members reducing crude oil output in 2017. The OPEC cut was partially offset by OPEC members not bound to production restrictions and from U.S shale production.

We have options to sell our oil though multiple pipelines and trucking routes. Each transportation route has varying effects on realized prices and transportation expenses. The following table shows the percentage of oil volumes we sold in Colombia using each transportation method for the three and six months ended June 30, 2017 and 2016 and the prior quarter:

	Three Months Ended March 31,	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2017	2016	2017	2016
Volume transported through pipeline	25 %	20 %	50 %	22 %	57 %
Volume sold at wellhead, trucking	50 %	52 %	50 %	52 %	35 %
Volume sold not at wellhead, trucking	25 %	28 %	— %	26 %	8 %
	100 %	100 %	100 %	100 %	100 %

Volumes not sold at the wellhead receive a higher realized price, but incur higher transportation expense. Volumes sold at the wellhead have the opposite effect of lower realized price, offset by lower transportation expense.

Transportation expenses for the three months ended June 30, 2017, increased by 4% to $6.5 million compared with the corresponding period in 2016. On a per BOE basis, transportation expenses decreased by 11% to $2.71 per BOE from $3.05 per BOE in the corresponding period in 2016. The decrease in transportation expenses per BOE was due to the use of transportation routes which had lower costs per BOE than the routes used in 2016.

Transportation expenses for the six months ended June 30, 2017, decreased by 28% to $13.4 million compared with the corresponding period in 2016. On a per BOE basis, transportation expenses decreased by 32% to $2.90 per BOE from $4.26 per BOE in the corresponding period in 2016. The decrease in transportation expenses per BOE was due to a higher percentage of volumes sold at the wellhead, as noted in the table above, and the use of transportation routes which had lower costs per BOE than the routes used in 2016.

Transportation expenses for the three months ended June 30, 2017, decreased 6% to $6.5 million compared with $6.9 million in the prior quarter. On a per BOE basis, transportation expenses decreased by 13% to $2.71 from $3.11 in the prior quarter. The decrease was primarily due to the use of transportation routes which had lower costs per BOE.

The following table shows the variance in our average realized prices net of transportation expenses in Colombia for the three and six months ended June 30, 2017 compared with the comparative period in 2016 and the prior quarter:

U.S. Dollars Per BOE Sales Volumes NAR	Second Quarter 2017 Compared with First Quarter 2017	Second Quarter 2017 Compared with Second Quarter 2016	Six Months Ended, June 30, 2017 Compared with Six Months Ended June 30, 2016
Average realized price net of transportation expenses for the comparative period	$ 39.37	$ 32.13	$ 25.36
(Decrease) increase in benchmark prices	(3.74)	$ 5.40	13.18
Decrease (increase) in quality and transportation discounts	1.37	(0.45)	(1.55)
Lower transportation expenses	0.42	0.34	1.38
Average realized price net of transportation expenses for period ended June 30, 2017	$ 37.42	$ 37.42	$ 38.37

Operating expenses for the three months ended June 30, 2017, increased by 53% to $27.2 million compared with the corresponding period in 2016. The increase was due to increased operating costs per BOE combined with higher sales volumes. On a per BOE basis, operating expenses increased by 31% to $11.38 per BOE from $8.70 per BOE, in the corresponding period in 2016 primarily as a result of increased workover expenses of $1.45 per BOE. In the comparative period in 2016, we deferred workover activity to the second half of the year due to low commodity prices. Excluding workover expenses, operating costs increased by $1.23 per BOE as discussed below.

In Colombia, operating costs for the three months ended June 30, 2017, increased by $2.81 per BOE compared with the corresponding period in 2016, primarily as a result of increased workover expenses of $1.53 per BOE. Excluding workover expenses, operating costs in Colombia increased by $1.28 per BOE primarily as result of reduced production in Costayaco and Moqueta related to the Mocoa landslides on April 1, 2017. As a consequence of the extensive damage to the regional electrical infrastructure that resulted in a loss of electrical power within the region, our Putumayo Basin operations were impacted. We were an early responder to aid Mocoa residents and regional authorities with the diversion of some of our assets to provide emergency relief and continue to provide support to the community at this time.

Costayaco and Moqueta operations were running solely on diesel and gas-fired electricity generation in this interim period, which led to prioritized oil production and water injection for a period of approximately two weeks during April 2017. After power was restored to the city of Mocoa, effective actions by government agencies, working in collaboration with Gran Tierra and other oil companies, led to a restoration of electrical power elsewhere in the Putumayo region. The electrical system in the region has experienced instability since the disaster and, throughout the quarter, we have had to utilize diesel generators to maintain production and injection at key wells during brief periods of electrical outage. We are currently expanding a gas to power facility in Costayaco and Moqueta which will enable consistent power generation. We expect the expanded facility to be in place by the end of 2017.

Additionally, on January 30, 2017, after several months of planning and discussion, we signed an agreement with Conservation International to launch NaturAmazonas, a five year reforestation and conservation program to be implemented by Conservation International in the Putumayo Region of Colombia. Conservation International is a non-government organization, well known for implementing and managing nature conservation projects around the world. During the three and six months ended June 30, 2017, operating expenses included $0.9 million and $1.7 million, respectively, related to this program.

Operating expenses for the six months ended June 30, 2017, increased by 39% to $51.1 million, compared with the corresponding period in 2016. The increase was due to increased operating costs per BOE combined with higher sales volumes. On a per BOE basis, operating expenses increased by 31% to $11.06 per BOE from $8.46 per BOE, in the corresponding period in 2016. Workover expenses increased by $1.06 compared with the corresponding period in the prior year. Excluding workover expenses, operating costs increased by $1.54 per BOE for the reasons discussed above.

Colombian operating expense for the six months ended June 30, 2017, increased by $2.63 per BOE compared with the corresponding period in 2016, primarily as a result of higher sales and increased workover expenses of $1.15. Excluding workover expenses, operating costs in Colombia increased by $1.48 per BOE primarily as a result of increased costs and production disruptions in the second quarter of 2017 as explained above.

Operating expenses increased by 14% to $27.2 million in the three months ended June 30, 2017, compared with $23.9 million in the prior quarter due to increased operating costs per BOE combined with higher sales volumes. On a per BOE basis, operating expenses increased by $0.66 to $11.38 per BOE for the three months ended June 30, 2017, from $10.72 per BOE in the prior quarter primarily as a result of increased workover expenses of $0.67 per BOE.

DD&A Expenses

	Three Months Ended June 30, 2017		Three Months Ended June 30, 2016	
	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	$30,130	$ 13.17	$30,458	$ 15.49
Brazil	1,050	10.02	1,024	13.92
Peru	243	—	71	—
Corporate	221	—	331	—
	$31,644	$ 13.23	$31,884	$ 15.63

	Six Months Ended June 30, 2017		Six Months Ended June 30, 2016	
	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	$55,065	$ 12.48	$66,194	$ 15.65
Brazil	2,263	10.69	1,742	13.85
Peru	469	—	212	—
Corporate	440	—	648	—
	$58,237	$ 12.59	$68,796	$ 15.80

DD&A expenses for the three and six months ended June 30, 2017, decreased to $31.6 million ($13.23 per BOE) and $58.2 million ($12.59 per BOE) from $31.9 million ($15.63 per BOE) and $68.8 million ($15.80 per BOE) in the comparable periods in 2016. On a per BOE basis, the decrease was due to lower costs in the depletable base and increased proved reserves.

On a per BOE basis, DD&A expenses increased by 11% to $13.23 per BOE for the three months ended June 30, 2017, from $11.91 per BOE in the prior quarter due to higher costs in the depletable base from capital expenditures during the quarter.

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Asset Impairment

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Impairment of oil and gas properties				
Colombia	$—	$78,208	$—	$132,776
Brazil	—	14,152	—	15,402
Peru	169	483	452	899
	169	92,843	452	149,077
Impairment of inventory	—	—	—	664
	$169	$92,843	$452	$149,741

Impairment losses in the comparative periods in 2016 in our Colombia and Brazil cost centers and inventory impairment were primarily due to lower oil prices. In accordance with GAAP, we used an average Brent price of $51.35 per bbl for the purposes of the June 30, 2017, ceiling test calculations (March 31, 2017 - $49.33; December 31, 2016 - $42.92; June 30, 2016 - $44.48; March 31, 2016 - $48.79; December 31, 2015 - $54.08).

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.

G&A Expenses

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	Three Months Ended June 30, 2017	2016	% Change	Six Months Ended June 30, 2017	2016	% Change
G&A Expenses Before Stock-Based Compensation	$ 7,563	$7,610	$5,987	27	$15,173	$11,638	30
Stock-Based Compensation	1,149	1,903	1,988	(4)	3,052	3,386	(10)
G&A Expenses, Including Stock-Based Compensation	$ 8,712	$9,513	$7,975	19	$18,225	$15,024	21
U.S. Dollars Per BOE							
G&A Expenses Before Stock-Based Compensation	$ 3.39	$3.18	$2.94	8	$3.28	$2.67	23
Stock-Based Compensation	0.51	0.80	0.97	(18)	0.66	0.78	(15)
G&A Expenses, Including Stock-Based Compensation	$ 3.90	$3.98	$3.91	2	$3.94	$3.45	14

G&A expenses before stock based compensation were consistent with the prior quarter. For the three and six months ended June 30, 2017, G&A expenses increased by 27% and 30%, respectively, from the corresponding periods in 2016. The increase was commensurate with our growth. Since June 30, 2016, we have completed two acquisitions, drilled 15 wells, and grown production 22% from 21,695 BOEPD in the second quarter of 2016 to 26,423 BOEPD in 2017.

After stock-based compensation and capitalized G&A and overhead recoveries, G&A expenses for the three and six months ended June 30, 2017, increased by 19% to $9.5 million ($3.98 per BOE) and by 21% to $18.2 million ($3.94 per BOE), respectively, from $8.0 million ($3.91 per BOE) and $15.0 million ($3.45 per BOE), respectively, in the corresponding periods in 2016. The increase was mainly due to the increased head count.

G&A expenses for the three months ended June 30, 2017, increased by 9% to $9.5 million ($3.94 per BOE) compared with $8.7 million ($3.90 per BOE) in the prior quarter.

Equity Tax Expense

For the six months ended June 30, 2017 and 2016, equity tax expense was $1.2 million and $3.1 million, respectively, and is a tax calculated based on our Colombian legal entities' balance sheets equity at January 1. The legal obligation for each year's equity tax liability arises on January 1 of each year, therefore, we recognize the annual amounts of the equity tax expense in our interim unaudited condensed consolidated statement of operations during the first quarter of each year.

Foreign Exchange Losses

For the three and six months ended June 30, 2017, we had foreign exchange losses of $3.9 million and $2.1 million, respectively, compared with foreign exchange losses of $0.8 million and $1.6 million, respectively, in the corresponding period in 2016. 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 and losses. The following table presents the change in the U.S. dollar against the Colombian peso for the three and six months ended June 30, 2017, and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Change in the U.S. dollar against the Colombian peso	strengthened by 6%	weakened by 4%	strengthened by 1%	weakened by 7%

Financial Instrument Gains and Losses

The following table presents the nature of our financial instruments gains for the three and six months ended June 30, 2017, and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2017	2016	2017	2016
Commodity price derivative gain	$(1,545)	$(1,334)	$(6,247)	$(1,334)
Foreign currency derivatives loss (gain)	98	(1,118)	(639)	(1,118)
Trading securities loss	—	1,380	—	2,225
	$(1,447)	$(1,072)	$(6,886)	$(227)

Income Tax Expense and Recovery

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Income (loss) before income tax	$6,490	$(86,396)	$38,057	$(156,541)
Current income tax expense	$1,772	$5,778	$9,189	$7,801
Deferred income tax expense (recovery)	11,525	(28,615)	22,904	(55,751)
Total income tax expense (recovery)	$13,297	$(22,837)	$32,093	$(47,950)
Effective tax rate			84 %	31 %
Deferred income tax recovery related to Colombia ceiling test impairment	$—	$31,300	$—	$53,100

Current income tax expense was lower in the three months ended June 30, 2017, compared with the corresponding period in 2016 primarily as a result of increased tax depreciation in Colombia. The deferred income tax expense of $11.5 million for the three months ended June 30, 2017, was primarily due to excess tax depreciation compared with accounting depreciation in Colombia. The deferred income tax recovery in the corresponding period in 2016 of $28.6 million included $31.3 million associated with ceiling test impairment losses in Colombia. In 2016, the income tax recovery associated with impairment losses in Peru and Brazil was offset by a full valuation allowance.

Current income tax expense was higher in the six months ended June 30, 2017, compared with the corresponding period in 2016 as a result of higher taxable income in Colombia. The deferred income tax expense of $22.9 million for the six months ended June 30, 2017, was primarily due to excess tax depreciation compared with accounting depreciation in Colombia. The deferred income tax recovery in the corresponding period in 2016 of $55.8 million included $53.1 million associated with ceiling test impairment losses in Colombia. In 2016, the income tax recovery associated with impairment losses in Peru and Brazil was offset by a full valuation allowance.

The effective tax rate was 84% in the six months ended June 30, 2017, compared with 31% in the corresponding period in 2016. The change in the effective tax rate for the six months ended June 30, 2017, was primarily due to an increase in expected taxes on account of higher taxable income, as well increases in the impact of foreign taxes, other permanent differences, foreign currency translation adjustments and the non-deductible third-party royalty in Colombia, partially offset by a decrease in the valuation allowance, other local taxes, and stock-based compensation.

For the six months ended June 30, 2017, the difference between the effective tax rate of 84% and the 35% U.S. statutory rate was primarily due to an increase in expected taxes on account of higher taxable income, as well increases in the impact of foreign taxes, other permanent differences, valuation allowance largely attributable to losses incurred in the U.S. and Colombia, as well as the non-deductible third-party royalty in Colombia, stock-based compensation and other local taxes. For the six months ended June 30, 2016, the difference between the effective tax rate of 31% and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance, which was largely attributable to impairment losses in Brazil, as well as non-deductible local taxes, stock based compensation and a third-party royalty in Colombia. These items were partially offset by the impact of foreign taxes, foreign currency translation adjustments and other permanent differences, which mainly relates to non-taxable gain arising on the acquisition of Petroamerica and uncertain tax position adjustments, partially offset by prior periods true-up adjustments and other non-deductible expenses.

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Net Income and Funds Flow from Operations (a Non-GAAP Measure)

(Thousands of U.S. Dollars)	Second Quarter 2017 Compared with First Quarter 2017	% change	Second Quarter 2017 Compared with Second Quarter 2016	% change	Six Months Ended, June 30, 2017 Compared with Six Months Ended June 30, 2016	% change
Net income (loss) for the comparative period	$ 12,771		$ (63,559)		$ (108,591)	
Increase (decrease) due to:						
Prices	(5,278)		12,049		53,654	
Sales volumes	6,747		12,366		8,017	
Expenses:						
Operating	(3,271)		(9,460)		(14,330)	
Transportation	450		(275)		5,111	
Cash G&A and RSU settlements, excluding stock-based compensation expense	111		(1,290)		(2,855)	
Transaction	—		—		1,237	
Severance	—		281		1,299	
Interest, net of amortization of debt issuance costs	(221)		(999)		(3,110)	
Realized foreign exchange	968		545		542	
Settlement of financial instruments	(320)		445		1,169	
Current taxes	5,645		4,006		(1,388)	
Equity tax	1,224		—		1,827	
Other	(161)		(503)		(545)	
Net change in funds flow from comparative period	5,894		17,165		50,628	
Expenses:						
Depletion, depreciation and accretion	(5,051)		240		10,559	
Asset impairment	114		92,674		149,289	
Deferred tax	(146)		(40,140)		(78,655)	
Amortization of debt issuance costs	(15)		(131)		(596)	
Stock-based compensation, net of RSU settlement	(912)		(248)		(346)	
Financial instruments loss, net of financial instruments settlements	(3,672)		(70)		5,490	
Unrealized foreign exchange	(6,714)		(3,662)		(1,026)	
Loss on sale of Brazil business unit	(9,076)		(9,076)		(9,076)	
Gain on acquisition	—		—		(11,712)	
Net change in net income or loss	(19,578)		56,752		114,555	
Net income (loss) for the current period	$ (6,807)	(153)%	$ (6,807)	89 %	$ 5,964	105 %

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2017 Capital Program

We have narrowed the range of our projected 2017 capital program to $200 million to $225 million. We expect to finance our 2017 capital program through cash flows from operations and available capacity under our credit facility, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions.

Capital expenditures during the three months ended June 30, 2017, were $57.9 million:

(Thousands of U.S. Dollars)	
Colombia	$55,436
Brazil	1,062
Peru	1,002
Corporate	365
	$57,865

The significant elements of our second quarter 2017 capital program were:

Colombia

- On the Chaza Block (100% working interest ("WI"), operated), we completed the Costayaco-28 horizontal development well and successfully drilled and completed the second horizontal well, Costayaco-29. Preparations are underway for production testing at Costayaco-29. We also commenced a workover on the Moqueta-21 well.

- On the Putumayo-7 Block (100% WI, operated), we drilled the Confianza-1 exploration well and successfully tested two new zones - U Sand and A Limestone and perforated the N Sand. We are currently executing two seismic programs. The first, the Cumplidor 3-D seismic program completed subsequent to the quarter. The second 3-D seismic survey is underway.

- On the Midas Block (100% WI, operated), we completed the Acordionero-8i well as a planned water injector, continued drilling and completed the Acordionero-9 well and tested a new oil zone in the Lisama D, completed the Acordionero-10 well, drilled and completed the Acordionero-11 well, drilled the Acordionero-12 well and commenced drilling the Acordionero-13 well. We also performed a workover on the Acordionero-7 well.

- On the Putumayo-1 Block (55% WI, operated), we drilled the Vonu-1 exploration well.

- On the Suroriente Block (15.8% WI, non-operated), we drilled the Cohembi-20 development well.

- We continued facilities work at the Moqueta and Acordionero Fields.

Liquidity and Capital Resources

(Thousands of U.S. Dollars)	As at June 30, 2017	% Change	December 31, 2016
Cash and Cash Equivalents	$53,310	112	$ 25,175
Current Restricted Cash and Cash Equivalents	$5,844	(30)	$ 8,322

Revolving Credit Facility	$155,000	72	$ 90,000
Convertible Senior Notes	$115,000	—	$ 115,000

We believe that our capital resources, including cash on hand, cash generated from operations and available capacity on our credit facility, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2017, given current oil price trends and production levels. In accordance with our investment policy, available cash balances are held in our primary cash management banks in interest earning current accounts or may be invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At June 30, 2017, we had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. As a result of the semi-annual redetermination of the committed borrowing base under our revolving credit facility, the committed borrowing base was increased from $250 million to $300 million effective June 1, 2017. The next re-determination of the borrowing base is due to occur no later than November 2017. Borrowings under the revolving credit facility will mature on September 18, 2018.

Under the terms of our 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 net income plus interest, taxes, depreciation, depletion, amortization, exploration expenses and all non-cash charges minus all non-cash income ("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 June 30, 2017, we were in compliance with all financial and operating covenants in our credit agreement. Under the terms of the credit facility, we are limited in our ability to pay any dividends to our shareholders without bank approval.

The Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted.

Cash and Cash Equivalents Held Outside of Canada and the United States

At June 30, 2017, 99% 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.

In Colombia, we participate in a special exchange regime, and we 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.

Derivative Positions

At June 30, 2017, we had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold Put ($/bbl)	Purchased Put ($/bbl)	Sold Call ($/bbl)
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65

At June 30, 2017, we had no outstanding foreign currency derivative positions. Subsequent to the quarter end, we executed the following foreign currency derivative positions:

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged [1] (Thousands of U.S. Dollars)	Reference	Purchased Call (COP)	Sold Put (COP, Weighted Average Rate)
Collar: July 1, 2017 to July 31, 2017	5,000	1,646	COP	3,000	3,138
Collar: August 1, 2017 to August 31, 2017	23,000	7,570	COP	3,000	3,116
Collar: September 1, 2017 to September 29, 2017	23,000	7,570	COP	3,000	3,105
Collar: October 1, 2017 to October 31, 2017	23,000	7,570	COP	3,000	3,117
Collar: November 1, 2017 to November 30, 2017	25,000	8,228	COP	3,000	3,139
Collar: December 1, 2017 to December 28, 2017	25,000	8,228	COP	3,000	3,142
	124,000	40,812			

[1] At June 30, 2017 foreign exchange rate.

Cash Flows

The following table presents our primary sources and uses of cash and cash equivalents for the periods presented:

	Six Months Ended June 30, 2017	2016
Sources of cash and cash equivalents:		
Funds flow from operations	$95,946	$45,318
Proceeds from bank debt, net of issuance costs	98,304	—
Proceeds from sale of Brazil business unit, net of cash sold	34,481	—
Cash deposit received for letter of credit arrangements upon sale of Brazil business unit	4,700	—
Proceeds from issuance of Notes, net of issuance costs	—	108,900
Foreign exchange gain on cash, cash equivalents and restricted cash and cash equivalents	—	1,946
Proceeds from issuance of shares	—	5,350
	233,431	161,514
Uses of cash and cash equivalents:		
Additions to property, plant and equipment	(104,025)	(44,587)
Additions to property, plant and equipment - property acquisitions	(30,410)	(19,388)
Repayment of debt	(33,000)	—
Repurchase of shares of Common Stock	(10,000)	—
Net changes in assets and liabilities from operating activities	(28,112)	(6,630)
Changes in non-cash investing working capital	(627)	(11,059)
Settlement of asset retirement obligations	(298)	(464)
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	(1,175)	—
Acquisition of PetroAmerica, net of cash acquired	—	(40,201)
	(207,647)	(122,329)
Net increase in cash and cash equivalents and restricted cash and cash equivalents	$25,784	$39,185

Cash provided by operating activities in the six months ended June 30, 2017, was primarily affected by higher funds flow from operations (see funds flow from operations reconciliation under the heading 'Consolidated Results of Operations' above) and a $28.1 million change in assets and liabilities from operating activities.

One of the primary sources of variability in our cash flows from operating activities is the fluctuation in oil prices, the impact of which we partially mitigate by entering into commodity derivatives. Sales volume changes and costs related to operations and debt service also impact cash flow. Our cash flows from operating activities are also impacted by foreign currency exchange rate changes, the impact of which we partially mitigate by entering into foreign currency derivatives.

Off-Balance Sheet Arrangements

As at June 30, 2017, we had no off-balance sheet arrangements.

Contractual Obligations

During the six months ended June 30, 2017, we borrowed a net amount of $65.3 million on our revolving credit facility. Additionally, at June 30, 2017, we sold our Brazil business unit and its related obligations. Except as noted above, as at June 30, 2017, there were no other material changes to our contractual obligations outside of the ordinary course of business from those as at December 31, 2016.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2016 Annual Report on Form 10-K, filed with the SEC on March 1, 2017, and have not changed materially since the filing of that document, other than as follows:

Full Cost Method of Accounting and Impairments of Oil and Gas Properties

In the six months ended June 30, 2017, we had no ceiling test impairment losses in our Colombia and Brazil cost centers. We used an average Brent price of $51.35 per bbl for the purposes of the June 30, 2017, ceiling test calculations (March 31, 2017 - $49.33; December 31, 2016 - $42.92; June 30, 2016 - $44.48; March 31, 2016 - $48.79; December 31, 2015 - $54.08).

Holding all factors constant other than benchmark oil prices, it is reasonably likely that we will not experience ceiling test impairment losses in our Colombia cost center in the third quarter of 2017. 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 do not believe that ceiling test impairment losses will be experienced in the third quarter of 2017. The calculation of the impact of higher 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 $52.05 per bbl for the year ended September 30, 2017. 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 ten months ended July 31, 2017, and, for the two months ended September 30, 2017, estimated oil prices for the third quarter of 2017 using the forward price curve forecast from Bloomberg dated June 30, 2017.

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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity price 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. 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.

We have entered into commodity price derivative contracts to manage the variability in cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending.

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 100% of our revenues are related to the U.S. dollar price of Brent or WTI 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 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 Colombia and Peru are in local currency. Certain G&A expenses incurred at our head office in Canada are denominated in Canadian dollars. 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.

We have entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. We are exposed to interest rate fluctuations on our revolving credit facility, which bears floating rates of interest. At June 30, 2017, our outstanding revolving credit facility was $155.0 million (December 31, 2016 - $90.0 million), which had a weighted-average interest rate of approximately 3.7%. A 10% change in LIBOR would not materially impact our interest expense on debt outstanding at June 30, 2017.

Further information

See Note 10 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for further information regarding our derivative contracts, including the notional amounts and call and put prices by expected (contractual) maturity dates. Expected cash flows from the derivatives equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. We do not hold any of these derivative contracts for trading purposes.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our disclosure controls and procedures are designed 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. 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 June 30, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - Other Information

Item 1. Legal Proceedings

See Note 9 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for material developments with respect to matters previously reported in our Annual Report on Form 10-K for the year ended December 31, 2016, and material matters that have arisen since the filing of such report.

Item 1A. Risk Factors

See Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the fiscal year ended December 31, 2016. The risks facing our company have not changed materially from those set forth in Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

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

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)
Month #1 (April 1, 2017 - April 30, 2017)	—	—	—	19,540,359
Month #2 (May 1, 2017 - May 31, 2017)	1,138,246	2.44	1,138,246	18,402,113
Month #3 (June 1, 2017 - June 30, 2017)	3,097,644	2.33	3,097,644	15,304,469
Total	4,235,890	2.36	4,235,890	15,304,469

(1) Based on settlement date.

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

(3) On February 6, 2017, the Company announced that it intended to implement a new share repurchase program (the “2017 Program”) through the facilities of the Toronto Stock Exchange ("TSX"), the NYSE American and eligible alternative trading platforms in Canada and the United States. The Company received regulatory approval from the TSX to commence the 2017 Program on February 6, 2017. Under the 2017 Program, the Company is able to purchase at prevailing market prices up to 19,540,359 shares of Common Stock, representing 5.0% of the issued and outstanding shares of Common Stock as of January 27, 2017.

Shares purchased pursuant to the 2017 Program will be canceled. The 2017 Program will expire on February 7, 2018, or earlier if the 5.0% share maximum is reached. The 2017 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 2017 Program.

Item 6. Exhibits

The exhibits required to be filed by Item 6 are set forth in the Exhibit Index accompanying this Quarterly Report.

SIGNATURES

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

GRAN TIERRA ENERGY INC.

Date: August 3, 2017	/s/ Gary S. Guidry By: Gary S. Guidry President and Chief Executive Officer (Principal Executive Officer)
Date: August 3, 2017	/s/ Ryan Ellson By: Ryan Ellson Chief Financial Officer (Principal Financial and Accounting Officer)

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).
2.2	Plan of Conversion, dated October 31, 2016.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.1	Certificate of Incorporation.	Incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.2	Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (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).
4.5	Indenture related to the 5.00% Convertible Senior Notes due 2021, dated as of April 6, 2016, between Gran Tierra Energy Inc. and U.S. Bank National Association	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.6	Form of 5.00% Convertible Senior Notes due 2021	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.7	Subscription Receipt Agreement, dated July 8, 2016, by and between Gran Tierra Energy Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
4.8	Form of Registration Rights Agreement.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on

		July 14, 2016 (SEC File No. 001-34018).
10.1	Sixth Amendment to Credit Agreement, dated as of June 1, 2017, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., the Bank of Nova Scotia 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 May 18, 2017 (SEC File No. 001-34018).
10.2	Seventh Amendment to Credit Agreement, dated as of June 30, 2017, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., the Bank of Nova Scotia and the lenders party thereto.	Filed herewith.
10.3	Share and Loan Purchase Agreement, dated February 5, 2017, by Gran Tierra Energy International Holdings Ltd., Gran Tierra Luxembourg Holdings S. Á. R.L. and Maha Energy AB	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on July 6, 2017 (SEC File No. 001-34018).

10.4	Amendment #1, dated May 30, 2017, to the Share and Loan Purchase Agreement dated February 5, 2017 between Gran Tierra Energy International Holdings Ltd., Gran Tierra Luxembourg Holdings S.Á.R.L. and Maha Energy AB.	Incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K, filed with the SEC on July 6, 2017 (SEC File No. 001-34018).
10.5	Amendment #2, dated June 22, 2017, to the Share and Loan Purchase Agreement dated February 5, 2017 between Gran Tierra Energy International Holdings Ltd., Gran Tierra Luxembourg Holdings S.Á.R.L. and Maha Energy AB.	Incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K, filed with the SEC on July 6, 2017 (SEC File No. 001-34018).
10.6	Amendment #3, dated June 26, 2017, to the Share and Loan Purchase Agreement dated February 5, 2017 between Gran Tierra Energy International Holdings Ltd., Gran Tierra Luxembourg Holdings S.Á.R.L. and Maha Energy AB.	Incorporated by reference to Exhibit 2.4 to the Current Report on Form 8-K, filed with the SEC on July 6, 2017 (SEC File No. 001-34018).
12.1	Statement re: Computation of Ratio of Earnings to Fixed Charges	Filed herewith.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished 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.