TRANSATLANTIC PETROLEUM LTD.
Form 10-Q
August 08, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended: June 30, 2018

OR

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: 001-34574

TRANSATLANTIC PETROLEUM LTD.

(Exact name of registrant as specified in its charter)

Bermuda (State or Other Jurisdiction of Incorporation or Organization)	None (I.R.S. Employer Identification No.)
16803 Dallas Parkway	
Addison, Texas	75001

(Address of Principal Executive Offices) (Zip Code)
Registrant's Telephone Number, Including Area Code: (214) 220-4323

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 No

Indicate by check mark whether the registrant has 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 is required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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. (Check one):

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company
		Emerging growth company

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

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

As of August 6, 2018, the registrant had 50,591,375 common shares outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements
TRANSATLANTIC PETROLEUM LTD.

Consolidated Balance Sheets

(in thousands of U.S. Dollars, except share data)

	June 30, 2018 (unaudited)	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,715	$ 18,926
Accounts receivable, net		
Oil and natural gas sales	17,997	15,808
Joint interest and other	1,121	1,576
Related party	1,153	1,023
Prepaid and other current assets	7,333	3,866
Inventory	6,198	7,494
Total current assets	52,517	48,693
Property and equipment:		
Oil and natural gas properties (successful efforts method)		
Proved	173,942	193,647
Unproved	15,969	24,445
Equipment and other property	12,525	14,075
	202,436	232,167
Less accumulated depreciation, depletion and amortization	(114,109)	(129,183)
Property and equipment, net	88,327	102,984
Other long-term assets:		
Other assets	661	2,247
Note receivable - related party	6,287	6,726
Total other assets	6,948	8,973
Total assets	$ 147,792	$ 160,650
LIABILITIES, SERIES A PREFERRED SHARES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 5,588	$ 4,853
Accounts payable - related party	3,388	3,141
Accrued liabilities (1)	11,990	10,014
Derivative liability	2,882	2,215
Asset retirement obligations - current	4	-
Loans payable	19,175	15,625
Total current liabilities	43,027	35,848
Long-term liabilities:		
Asset retirement obligations less current portion	4,143	4,727
Accrued liabilities	7,838	8,810

Deferred income taxes	16,957	19,611
Loans payable	11,200	13,000
Total long-term liabilities	40,138	46,148
Total liabilities	83,165	81,996
Commitments and contingencies		
Series A preferred shares, $0.01 par value, 426,000 shares authorized; 426,000 shares issued and outstanding with a liquidation preference of $50 per share as of June 30, 2018 and December 31, 2017	21,300	21,300
Series A preferred shares-related party, $0.01 par value, 495,000 shares authorized; 495,000 shares issued and outstanding with a liquidation preference of $50 per share as of June 30, 2018 and December 31, 2017	24,750	24,750
Shareholders' equity:		
Common shares, $0.10 par value, 100,000,000 shares authorized; 50,591,375 shares and 50,319,156 shares issued and outstanding as of June 30, 2018 and December 31, 2017, respectively	5,059	5,032
Treasury stock	(970)	(970)
Additional paid-in-capital	575,591	575,411
Accumulated other comprehensive loss	(136,218)	(124,766)
Accumulated deficit	(424,884)	(422,103)
Total shareholders' equity	18,578	32,604
Total liabilities, Series A preferred shares and shareholders' equity	$ 147,792	$ 160,650

(1) Includes income tax payable of $7.3 million and $6.2 million at June 30, 2018 and December 31, 2017, respectively.

The accompanying notes are an integral part of these unaudited consolidated financial statements.

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Operations and Comprehensive (Loss) Income

(Unaudited)

(U.S. Dollars and shares in thousands, except per share amounts)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues:				
Oil and natural gas sales	$18,100	$12,283	$34,761	$28,051
Sales of purchased natural gas	1	-	1	654
Other	97	58	362	72
Total revenues	18,198	12,341	35,124	28,777
Costs and expenses:				
Production	2,803	2,714	5,672	5,801
Transportation and processing	1,138	-	2,331	-
Exploration, abandonment and impairment	191	2	231	108
Cost of purchased natural gas	1	-	1	568
Seismic and other exploration	59	65	218	80
General and administrative	3,786	3,181	7,123	6,771
Depreciation, depletion and amortization	3,276	4,255	7,735	8,752
Accretion of asset retirement obligations	43	47	89	95
Total costs and expenses	11,297	10,264	23,400	22,175
Operating income	6,901	2,077	11,724	6,602
Other income (expense):				
Loss on sale of TBNG	-	-	-	(15,226)
Interest and other expense	(2,091)	(2,288)	(4,873)	(4,659)
Interest and other income	377	188	631	481
(Loss) gain on derivative contracts	(3,141)	676	(3,866)	1,664
Foreign exchange (loss) gain	(1,938)	1,116	(3,996)	(1,007)
Total other expense	(6,793)	(308)	(12,104)	(18,747)
Income (loss) from operations before income taxes	108	1,769	(380)	(12,145)
Income tax expense	(1,114)	(1,203)	(2,401)	(3,338)
Net income (loss)	(1,006)	566	(2,781)	(15,483)
Other comprehensive income (loss):				
Foreign currency translation adjustment	(9,109)	2,132	(11,452)	23,051
Comprehensive (loss) income	$(10,115)	$2,698	$(14,233)	$7,568
Net earnings (loss) per common share				

Basic net earnings (loss) per common share				
Continuing operations	$(0.02)	$0.01	$(0.06)	$(0.33)
Weighted average common shares outstanding	50,420	47,412	50,397	47,355
Diluted net earnings (loss) per common share				
Continuing operations	$(0.02)	$0.01	$(0.06)	$(0.33)
Weighted average common and common equivalent shares outstanding	50,420	47,826	50,397	47,355

The accompanying notes are an integral part of these unaudited consolidated financial statements.

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statement of Equity

(Unaudited)

(U.S. Dollars and shares in thousands)

	Common Shares	Treasury Shares	Warrants	Common Shares	Treasury Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Accumulated Deficit	Total Shareholders' Equity
Balance at December 31, 2017	50,319	333	700	$ 5,032	$ (970)	$ 575,411	$ (124,766)	$ (422,103)	$ 32,604
Expiration of warrants	-	-	(700)	-	-	-	-	-	-
Issuance of restricted stock units	272	-	-	27	-	(27)	-	-	-
Share-based compensation	-	-	-	-	-	218	-	-	218
Tax effect of restricted stock	-	-	-	-	-	(11)	-	-	(11)
Foreign currency translation adjustment	-	-	-	-	-	-	(11,452)	-	(11,452)
Net loss	-	-	-	-	-	-	-	(2,781)	(2,781)
Balance at June 30, 2018	50,591	333	0	$ 5,059	$ (970)	$ 575,591	$ (136,218)	$ (424,884)	$ 18,578

The accompanying notes are an integral part of these unaudited consolidated financial statements.

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Cash Flows

(Unaudited)

(in thousands of U.S. Dollars)

	For the Six Months Ended June 30,	
	2018	2017
Operating activities:		
Net loss	$(2,781)	$(15,483)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Share-based compensation	218	414
Foreign currency loss	6,928	143
Loss (gain) on commodity derivative contracts	3,866	(1,664)
Cash settlement on derivative contracts	(3,199)	32
Loss on sale of TBNG	-	15,226
Amortization on loan financing costs	21	61
Deferred income tax expense	1,431	2,479
Exploration, abandonment and impairment	231	108
Depreciation, depletion and amortization	7,735	8,752
Accretion of asset retirement obligations	89	95
Changes in operating assets and liabilities:		
Accounts receivable	(4,971)	7,188
Prepaid expenses and other assets	(4,558)	1,340
Accounts payable and accrued liabilities	7,224	(5,114)
Net cash provided by operating activities	12,234	13,577
Investing activities:		
Additions to oil and natural gas properties	(10,898)	(11,331)
Additions to equipment and other properties	(548)	(356)
Restricted cash	-	-
Proceeds from the sale of TBNG	-	17,779
Net cash (used in) provided by investing activities	(11,446)	6,092
Financing activities:		
Tax withholding on restricted share units	(15)	(86)
Loan proceeds	10,000	-
Loan repayment	(8,250)	(12,775)
Loan repayment - related party	-	(2,694)
Net cash provided by (used in) financing activities	1,735	(15,555)
Effect of exchange rate on cash flows, cash equivalents, and restricted cash	(4,104)	(1,713)
Net (decrease) increase in cash, cash equivalents and restricted cash	(1,581)	2,401
Cash, cash equivalents and restricted cash, beginning of period (1)	20,431	15,071
Cash, cash equivalents and restricted cash, end of period (2)	$18,850	$17,472
Supplemental disclosures:		

Cash paid for interest	$5,236	$4,400
Cash paid for taxes	$534	$1,460

(1) The beginning of period balance at December 31, 2016 includes cash and cash equivalents of $10.0 million, restricted cash of $3.5 million in other assets and TBNG cash held for sale of $1.6 million. The beginning of period balance at December 31, 2017 includes cash and cash equivalents of $18.9 million and restricted cash of $1.5 million in other assets

(1) The end of period balance at June 30, 2017 includes cash and cash equivalents of $12.3 million and restricted cash of $5.2 million in other assets. The end of period balance at June 30, 2018 includes cash and cash equivalents of $18.7 million and restricted cash of $0.1 million in other assets.

The accompanying notes are an integral part of these unaudited consolidated financial statements.

Transatlantic Petroleum Ltd.

Notes to Consolidated Financial Statements

(Unaudited)

1. General

Nature of operations

TransAtlantic Petroleum Ltd. (together with its subsidiaries, “we,” “us,” “our,” the “Company” or “TransAtlantic”) is an international oil and natural gas company engaged in acquisition, exploration, development and production. We have focused our operations in countries that have established, yet underexplored petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. We hold interests in developed and undeveloped oil and natural gas properties in Turkey and Bulgaria. As of August 6, 2018, approximately 47% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, our chief executive officer and chairman of our board of directors.

We are a holding company with two operating segments – Turkey and Bulgaria. Our assets consist of our ownership interests in subsidiaries that primarily own assets in Turkey and Bulgaria.

Basis of presentation

Our consolidated financial statements are expressed in U.S. Dollars and have been prepared by management in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”). All amounts in the notes to the consolidated financial statements are in U.S. Dollars unless otherwise indicated. The unaudited consolidated financial statements include accounts of the Company and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. In preparing financial statements, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews estimates, including those related to fair value measurements associated with acquisitions and financial derivatives, the recoverability and impairment of long-lived assets, contingencies and income taxes. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Certain information and footnote disclosures normally included in the consolidated financial statements prepared in accordance with U.S. GAAP have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Form 10-K for the year ended December 31, 2017.

On February 24, 2017, we closed the sale of our ownership interests in our subsidiary Thrace Basin Natural Gas (Turkiye) Corporation (“TBNG”) for gross proceeds of $20.7 million, and approximate net cash proceeds of $16.1 million, which amounts reflect a $0.2 million post-closing purchase price adjustment.

We classified the assets and liabilities of TBNG within the captions “Assets held for sale” and “Liabilities held for sale” on our consolidated balance sheets as of December 31, 2016. Although the sale of TBNG met the threshold to classify its assets and liabilities as held for sale, it didn’t meet the requirements to classify its operations as discontinued as the sale wasn’t considered a strategic shift in our operations. As such, TBNG’s results of operations are classified as continuing operations for all periods presented (See Note 13. “Assets and liabilities held for sale and discontinued operations”).

Revenue recognition

As explained below, on January 1, 2018, we adopted Financial Accounting Standards Board (“FASB”) Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers (Topic 606), under the modified retrospective method. Under this method, we recognize the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings; however, no adjustment was required as a result of adopting the new revenue standard. Results for reporting periods beginning after January 1, 2018 are presented under the new standard. The comparative information has not been restated and continues to be reported under the historic accounting standards in effect for those periods. We do not expect any impact to our net income from the adoption of ASU 2014-09 on an ongoing basis.

Our revenue consists of sales under two contracts, one for crude oil and one for natural gas. The crude oil is delivered to the inlet of a processing center and control is passed through a custodian to the customer at that point. We are paid for crude oil at the inlet plus or minus an adjustment for quality. Our natural gas is metered at the inlet of a transportation pipeline and control is passed at that point.

We record natural gas sales at the delivery point to the customer, net of any pricing differentials. There is no material inventory remaining at the end of each reporting period.

We have previously deducted any transportation costs, processing fees, or adjustments from revenue and recorded the net amount. Under the new revenue guidance, on January 1, 2018, we now record the gross amount of the revenue and records any fees, or deductions as expenses. Our revenue excludes any amounts collected on behalf of third parties.

2. Recent accounting pronouncements

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, its final standard on revenue from contracts with customers. ASU 2014-09 outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity recognizes revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In applying the revenue model to contracts within its scope, an entity identifies the contract(s) with a customer, identifies the performance obligations in the contract, determines the transaction price, allocates the transaction price to the performance obligations in the contract and recognizes revenue when (or as) the entity satisfies a performance obligation. ASU 2014-09 applies to all contracts with customers and requires significantly expanded disclosures about revenue recognition. ASU 2014-09 has been amended several times with subsequent ASUs including ASU 2015-14 Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.

We adopted ASU 2014-09 on January 1, 2018 using the modified retrospective approach. We have a small number of contracts with customers and have identified transactions within the scope of the standard. As a result of adoption of ASU 2014-09, we have determined that it will change our method of recording certain transportation and processing charges that were previously recorded as a reduction of revenues to record such charges as an expense under the new standard. The result of this change was an increase to both revenue and expenses of $2.3 million for the six months ended June 30, 2018. The application of the new standard has no impact on our retained earnings and no impact to our net income on an ongoing basis. During the six months ended June 30, 2017, this standard would have increased both revenue and expenses by $2.3 million.

Contracts for the sale of natural gas and crude oil are evidenced by (1) base contracts for the sale and purchase of natural gas or crude oil, which document the general terms and conditions for the sale, and (2) transaction confirmations, which document the terms of each specific sale.

Revenue is measured based on consideration specified in the contract with the customer. We recognize revenue in the amount that reflects the consideration we expect to be entitled to in exchange for transferring control of those goods to the customer. Revenues are recognized for the sale of our net share of production volumes. Sales on behalf of other working interest owners and royalty interest owners are not recognized as revenues. The contract consideration in our contracts are typically allocated to specific performance obligations in the contract according to the price stated in the contract, which usually sets the base oil and natural gas prices based on benchmark prices based on volumes and adjustments for product quality. Payment is generally received one or two months after the sale has occurred.

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2017
	(in thousands)			
Disaggregation of revenue				
Product type				
Oil	$17,830	$34,155	$13,090	$29,144
Natural gas	270	606	317	1,230
Total revenue from customers	$18,100	$34,761	$13,407	$30,374

*As noted above, prior period amounts have not been adjusted under the modified retrospective method.

All of our revenues from contracts with customers represent products transferred at the point in time control is transferred to the customer and are generated in Turkey.

Transaction price allocated to remaining performance obligations. A significant number of our product sales are short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient exempting us from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Contract balances. Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were \$18.0 million and \$15.8 million as of June 30, 2018 and December 31, 2017, respectively, and are reported in accounts receivable, net on our consolidated balance sheets. We currently have no assets or liabilities related to our revenue contracts, including no upfront or rights to deficiency payments.

Practical expedients. We have made use of certain practical expedients in adopting the new revenue standard, including the value of unsatisfied performance obligations are not disclosed for (i) contracts with an original expected length of one year or less, (ii) contracts for which we recognize revenue at the amount to which we have the right to invoice, (iii) variable consideration which is allocated entirely to a wholly unsatisfied performance obligation and meets the variable allocation criteria in the standard and (iv) only contracts that are not completed at transition. We have not adjusted the promised amount of consideration for the effects of a significant financing component if we expect, at contract inception, that the period between when we transfer a promised good or service to the customer and when the customer pays for that good or service will be one year or less.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842) (“ASU 2016-02”), which requires companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The guidance requires adoption by application of a modified retrospective transition approach for existing long-term leases and is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. Oil and natural gas leases are excluded from the provisions of ASU 2016-02. As of June 30, 2018, we currently have 21 operating leases within the scope of this standard, with the last lease expiring in 2022. The effect of ASU 2016-02 will require the Company to disclose the right of use asset and the related liability. We are currently evaluating the impact that ASU 2016-02 would have on our consolidated financial statements and results of operations.

In June 2016, the FASB issued ASU 2016-13, Financial Instruments - Credit Losses (“ASU 2016-13”). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, held-to-maturity debt securities and loans, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowance for losses. This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted for a fiscal year beginning after December 15, 2018, including interim periods within that fiscal year. Entities will apply the standard’s provisions as a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is adopted. We are currently assessing the potential impact of ASU 2016-13 on our consolidated financial statements and results of operations.

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (“ASU 2016-15”). ASU 2016-15 reduces diversity in practice in how certain transactions are classified in the statement of cash flows. The amendments in ASU 2016-15 provide guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, and distributions received from equity method investees. ASU 2016-15 is effective for annual and interim periods beginning after December 15, 2017. We adopted ASU 2016-15 effective January 1, 2018. The adoption of ASU 2016-15 had no impact on our retained earnings or net income.

In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash ("ASU 2016-18"). ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statements of cash flows. We adopted ASU 2016-18 effective January 1, 2018. The adoption of ASU 2016-18 had no impact on our retained earnings, and no impact to our net income on an ongoing basis. The amendments have been applied using a retrospective transition method to each period presented, as required. The period ended June 30, 2017 has been reclassified to reflect this change.

In May 2017, the FASB issued ASU 2017-09, Scope of Modification Accounting, which clarifies Topic 718, Compensation – Stock Compensation, such that an entity must apply modification accounting to changes in the terms or conditions of a share-based payment award unless all of the following criteria are met: (1) the fair value of the modified award is the same as the fair value of the original award immediately before the modification and the ASU indicates that if the modification does not affect any of the inputs to the valuation technique used to value the award, the entity is not required to estimate the value immediately before and after the modification; (2) the vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the modification; and (3) the classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the modification. The ASU is effective for fiscal years beginning after December 15, 2017. We expect the adoption of this ASU will only impact consolidated financial statements if there is a modification to our share-based award agreements in the future.

In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities, which amends the hedge accounting recognition and presentation requirements in Accounting Standards Codification (“ASC”) Topic 815. The new standard provides partial relief on the timing of certain aspects of hedge documentation and eliminates the requirement to recognize hedge ineffectiveness separately in income. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018 and for interim periods therein. Early adoption as of the date of issuance is permitted. The new standard does not impact accounting for derivatives that are not designated as accounting hedges. We do not currently account for any of our derivative position as accounting hedges.

We have reviewed other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on our consolidated results of operations, financial position and cash flows. Based on that review, we believe that none of these pronouncements will have a significant effect on current or future earnings or operations.

3. Series A Preferred Shares

Series A Preferred Shares

As of June 30, 2018 and 2017, we had 921,000 outstanding shares of our 12.0% Series A Convertible Redeemable Preferred Shares (“Series A Preferred Shares”). The Series A Preferred Shares contain a substantive conversion option, are mandatorily redeemable and convert into a fixed number of common shares. As a result, under U.S GAAP, we have classified the Series A Preferred Shares within mezzanine equity in our consolidated balance sheets. As of June 30, 2018, there were $21.3 million of Series A Preferred Shares and $24.8 million of Series A Preferred Shares – related party outstanding (See Note 12. “Related party transactions”).

Pursuant to the Certificate of Designations for the Series A Preferred Shares (the “Certificate of Designations”), each Series A Preferred Share may be converted at any time, at the option of the holder, into 45.754 common shares (which is equal to an initial conversion price of approximately $1.0928 per common share and is subject to customary adjustments for stock splits, stock dividends, recapitalizations or other fundamental changes).

If not converted sooner, on November 4, 2024, we are required to redeem the outstanding Series A Preferred Shares in cash at a price per share equal to the liquidation preference plus accrued and unpaid dividends. At any time on or after November 4, 2020, we may redeem all or a portion of the Series A Preferred Shares at the redemption prices listed below (expressed as a percentage of the liquidation preference amount per share) plus accrued and unpaid dividends to the date of redemption, if the closing sale price of the common shares equals or exceeds 150% of the conversion price then in effect for at least 10 trading days (whether or not consecutive) in a period of 20 consecutive trading days, including the last trading day of such 20 trading day period, ending on, and including, the trading day immediately preceding the business day on which we issue a notice of optional redemption. The redemption prices for the 12-month period starting on the dates below are:

Period Commencing	Redemption Price
November 4, 2020	105.000%
November 4, 2021	103.000%
November 4, 2022	101.000%
November 4, 2023 and thereafter	100.000%

Additionally, upon the occurrence of a change of control, we are required to offer to redeem the Series A Preferred Shares within 120 days after the first date on which such change of control occurred, for cash at a redemption price equal to the liquidation preference per share, plus any accrued and unpaid dividends.

Dividends on the Series A Preferred Shares are payable quarterly at our election in cash, common shares or a combination of cash and common shares at an annual dividend rate of 12.0% of the liquidation preference if paid all in cash or 16.0% of the liquidation preference if paid in common shares. If paid partially in cash and partially in common shares, the dividend rate on the cash portion is 12.0%, and the dividend rate on the common share portion is 16.0%. Dividends are payable quarterly on March 31, June 30, September 30, and December 31 of each year. The holders of the Series A Preferred Shares also are entitled to participate pro-rata in any dividends paid on the common shares on an as-converted-to-common shares basis. For the three and six months ended June 30, 2018, we paid $1.3 million and $2.6 million, respectively, in cash dividends on the Series A Preferred Shares, which is recorded in our consolidated statements of comprehensive (loss) income under the caption “Interest and other expense”.

Except as required by Bermuda law, the holders of Series A Preferred Shares have no voting rights, except that for so long as at least 400,000 Series A Preferred Shares are outstanding, the holders of the Series A Preferred Shares voting as a separate class have the right to elect two directors to our Board of Directors. For so long as between 80,000 and 399,999 Series A Preferred Shares are outstanding, the holders of the Series A Preferred Shares voting as a separate class have the right to elect one director to our Board of Directors. Upon less than 80,000 Series A Preferred Shares remaining outstanding, any directors elected by the holders of Series A Preferred Shares shall immediately resign from our Board of Directors.

The Certificate of Designation also provides that without the approval of the holders of a majority of the outstanding Series A Preferred Shares, we will not issue indebtedness for money borrowed or other securities which are senior to the Series A Preferred Shares in excess of the greater of (i) $100 million or (ii) 35% of our PV-10 of proved reserves as disclosed in our most recent independent reserve report filed or furnished by us on EDGAR.

4. Property and equipment

Oil and natural gas properties

The following table sets forth the capitalized costs under the successful efforts method for our oil and natural gas properties as of:

	June 30, 2018	December 31, 2017
	(in thousands)	

Oil and natural gas properties, proved:		
Turkey	$173,421	$ 193,111
Bulgaria	521	536
Total oil and natural gas properties, proved	173,942	193,647
Oil and natural gas properties, unproved:		
Turkey	15,969	24,445
Total oil and natural gas properties, unproved	15,969	24,445
Gross oil and natural gas properties	189,911	218,092
Accumulated depletion	(108,599)	(123,225)
Net oil and natural gas properties	$81,312	$ 94,867

The decline in oil and natural gas properties during the six months ended June 30, 2018 was primarily driven by the devaluation of the Turkish Lira versus the U.S. Dollar. For the six months ended June 30, 2018, foreign currency translations reduced oil and natural gas properties and increased accumulated other comprehensive loss within shareholders' equity on our consolidated balance sheet.

At June 30, 2018 and December 31, 2017, we excluded $3.3 million and $0.5 million, respectively, from the depletion calculation for proved development wells currently in progress and for costs associated with fields currently not in production.

At June 30, 2018, the capitalized costs of our oil and natural gas properties, net of accumulated depletion, included $9.0 million relating to acquisition costs of proved properties, which are being depleted by the unit-of-production method using total proved reserves, and $57.2 million relating to well costs and additional development costs, which are being depleted by the unit-of-production method using proved developed reserves.

At December 31, 2017, the capitalized costs of our oil and natural gas properties included $11.2 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and $58.7 million relating to well costs and additional development costs, which are being amortized by the unit-of-production method using proved developed reserves.

Impairments of proved properties and impairment of exploratory well costs

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. We primarily use Level 3 inputs to determine fair value, including but not limited to, estimates of proved reserves, future commodity prices, the timing and amount of future production and capital expenditures and discount rates commensurate with the risk reflective of the lives remaining for the respective oil and natural gas properties.

During the six months ended June 30, 2018 and 2017, we recorded $0.1 million and $0.1 million, respectively, of impairment of proved properties and exploratory well costs which are primarily measured using Level 3 inputs.

Capitalized cost greater than one year

As of June 30, 2018, we had $2.4 million of exploratory well costs capitalized for the Pinar-1ST well in Turkey, which we spud in March 2014, and $4.5 million of exploratory well costs for the Cavuslu-1 well in Turkey, which we spud in June 2017. Both the Pinar-1ST well and Cavuslu-1 well started producing in 2018.

Equipment and other property

The historical cost of equipment and other property, presented on a gross basis with accumulated depreciation, is summarized as follows:

	June 30, 2018	December 31, 2017
	(in thousands)	
Inventory	$4,254	$ 4,619
Leasehold improvements, office equipment and software	6,272	7,214
Gas gathering system and facilities	224	135
Vehicles	348	343
Other equipment	1,426	1,764
Gross equipment and other property	12,525	14,075
Accumulated depreciation	(5,510)	(5,958)
Net equipment and other property	$7,015	$ 8,118

At June 30, 2018, in addition to above, we have classified $6.2 million of inventory as a current asset, which represents our expected inventory consumption in the next twelve months. We classify our materials and supply inventory as a long-term asset because such materials will ultimately be classified as a long-term asset when the material is used in the drilling of a well.

At June 30, 2018 and December 31, 2017, we excluded $10.5 million and $12.1 million of inventory, respectively, from depreciation as the inventory had not been placed into service.

5. Asset retirement obligations

The following table summarizes the changes in our asset retirement obligations ("ARO") for the six months ended June 30, 2018 and for the year ended December 31, 2017:

	June 30, 2018	December 31, 2017
	(in thousands)	
Asset retirement obligations at beginning of period	$4,727	$ 4,833
Liabilities settled	-	(37)
Foreign exchange change effect	(778)	(259)
Additions	109	-
Accretion expense	89	190
Asset retirement obligations at end of period	$4,147	$ 4,727

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Our ARO is measured using primarily Level 3 inputs. The significant unobservable inputs to this fair value measurement include estimates of plugging costs, remediation costs, inflation rate and well life. The inputs are calculated based on historical data as well as current estimated costs.

6. Derivative instruments

We use derivative instruments to manage certain risks related to commodity prices and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by our senior management. We do not hold any derivatives for speculative purposes and do not use derivatives with leveraged or complex features. We have not designated the derivative contracts as hedges for accounting purposes, and accordingly, we record the derivative contracts at fair value and recognize changes in fair value in earnings as they occur.

Commodity price derivatives

To the extent that a legal right of offset exists, we net the value of our derivative contracts with the same counterparty in our consolidated balance sheets. All of our oil derivative contracts are settled based upon Brent crude oil pricing. We recognize gains and losses related to these contracts on a fair value basis in our consolidated statements of comprehensive (loss) income under the caption "(Loss) gain on derivative contracts." Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows under the caption "Cash settlement on derivative contracts."

At June 30, 2018 and December 31, 2017, we had outstanding derivative contracts with respect to our future crude oil production as set forth in the tables below:

Fair Value of Commodity Derivative Instruments as of June 30, 2018

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Additional Call Ceiling	Estimated Fair Value of Liability (in thousands)
Collar	July 1, 2018 - December 31, 2018	440	$ 55.00	$ 70.00	$ -	$ (799)
Collar	July 1, 2018 - December 31, 2018	489	$ 56.00	$ 70.00	$ 84.00	(759)
Total Estimated Fair Value of Liability						$ (1,558)

Fair Value of Commodity Derivative Instruments as of December 31, 2017

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Additional Call Ceiling	Estimated Fair Value of Liability (in thousands)

Collar	January 1, 2018 — February 28, 2018	458	$ 50.00	$ 61.50	$ -	$	(178)
Collar	January 1, 2018 — March 31, 2018	500	$ 47.00	$ 59.65	$ -		(376)
Collar	January 1, 2018 — May 31, 2018	298	$ 47.50	$ 61.00	$ -		(286)
Collar	January 1, 2018 — June 30, 2018	746	$ 47.50	$ 57.10	$ -		(1,375)
Total Estimated Fair Value of Liability						$	(2,215)

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Foreign currency derivatives

To the extent that a legal right of offset exists, we net the value of our derivative contracts with the same counterparty in our consolidated balance sheets. All of our foreign exchange derivative contracts are settled based upon the contract rate. We recognize gains and losses related to these contracts on a fair value basis in our consolidated statements of comprehensive (loss) income under the caption "(Loss) gain on derivative contracts." Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows under the caption "Cash settlement on derivative contracts."

At June 30, 2018, we had outstanding derivative contracts with respect to our foreign exchange rates as set forth in the tables below:

Fair Value of Currency Derivative Instruments as of June 30, 2018

Type	Buy/Sell	Rate	Settlement Date	Buy Currency	Buy Currency Amount	Sell Currency	Sell Currency Amount	Estimated Fair Value of Liability
								(in thousands)
FXOPT	Buy	4.840	10/16/18	TRY	16,940,000	USD	3,500,000	$ (234)
FXOPT	Buy	4.790	09/03/18	TRY	4,790,000	USD	1,000,000	(169)
FXFWD	Sell	4.930	07/03/18	USD	1,500,000	TRY	7,397,550	(114)
FXFWD	Sell	4.960	07/17/18	USD	3,500,000	TRY	17,351,600	(263)
FXFWD	Sell	4.980	07/31/18	USD	1,500,000	TRY	7,475,250	(112)
FXFWD	Sell	5.010	08/14/18	USD	4,250,000	TRY	21,297,175	(315)
FXFWD	Sell	5.050	09/05/18	USD	1,600,000	TRY	8,085,760	(117)
Total Estimated Fair Value of Liability								$ (1,324)

During the three months ended June 30, 2018 and 2017, we recorded a net loss on derivative contracts of $3.1 million and a net gain of $0.7 million, respectively. During the six months ended June 30, 2018 and 2017, we recorded a net loss on derivative contracts of $3.9 million and a net gain of $1.7 million, respectively.

Balance sheet presentation

The following table summarizes both: (i) the gross fair value of our derivative instruments by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in our consolidated balance sheets at June 30, 2018 and December 31, 2017, and (ii) the net recorded fair value as reflected on our consolidated balance sheets at June 30, 2018 and December 31, 2017.

As of June 30, 2018

Type of Derivative Contract	Location on Consolidated Balance Sheets	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
		(in thousands)		
Commodity - crude oil	Current liabilities	$1,558	$ -	$ 1,558
Commodity - crude oil	Long-term liabilities	$-	$ -	$ -
Foreign exchange	Current liabilities	$1,324	$ -	$ 1,324
Foreign exchange	Long-term liabilities	$-	$ -	$ -

		As of December 31, 2017		
Type of Derivative Contract	Location on Consolidated Balance Sheets	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
		(in thousands)		
Commodity - crude oil	Current liabilities	$ 2,215	$ -	$ 2,215
Commodity - crude oil	Long-term liabilities	$ -	$ -	$ -
Foreign exchange	Current liabilities	$ -	$ -	$ -
Foreign exchange	Long-term liabilities	$ -	$ -	$ -

7. Loans payable

As of the dates indicated, our third-party debt consisted of the following:

	June 30, 2018	December 31, 2017
Fixed and floating rate loans	(in thousands)	
Term Loans (1)	$ 30,375	$ 28,625
Less: current portion	19,175	15,625
Long-term portion	$ 11,200	$ 13,000

(1) Includes the 2018 Term Loan, the 2017 Term Loan, and the 2016 Term Loan (each as defined below and collectively, “Term Loans”).

2016 Term Loan

On August 23, 2016, the Turkish branch of TransAtlantic Exploration Mediterranean International Pty Ltd (“TEMI”) entered into a Credit Agreement (the “Credit Agreement”) with DenizBank, A.S. (“DenizBank”). The Credit Agreement is a master agreement pursuant to which DenizBank may make loans to TEMI from time to time pursuant to additional loan agreements.

On August 31, 2016, DenizBank entered into a $30.0 million term loan (the “2016 Term Loan”) with TEMI under the Credit Agreement. In addition, we and DenizBank entered into additional agreements with respect to up to $20.0 million of non-cash facilities, including guarantee letters and treasury instruments for future hedging transactions.

The 2016 Term Loan bore interest at a fixed rate of 5.25% (plus 0.2625% for Banking and Insurance Transactions Tax per the Turkish government) per annum and was payable in six monthly installments of $1.25 million each through February 2017 and thereafter in twelve monthly installments of $1.88 million each through February 2018. On April 27, 2017, TEMI and DenizBank approved a revised amortization schedule for the 2016 Term Loan. Pursuant to the revised amortization schedule, the maturity date of the 2016 Term Loan was extended from February 2018 to June 2018, and the monthly principal payments were reduced from $1.88 million to $1.38 million. The other terms of the 2016 Term Loan remained unchanged. Amounts repaid under the 2016 Term Loan could not be re-borrowed and early repayments under the 2016 Term Loan were subject to early repayment fees.

The 2016 Term Loan was guaranteed by DMLP, Ltd. (“DMLP”), TransAtlantic Turkey, Ltd. (“TransAtlantic Turkey”), Talon Exploration, Ltd. (“Talon Exploration”) and TransAtlantic Worldwide, Ltd. (“TransAtlantic Worldwide”).

The 2016 Term Loan contained standard prohibitions on the activities of TEMI as the borrower, including prohibitions on granting of liens on its assets, incurring additional debt, dissolving, liquidating, merging, consolidating, paying dividends, making certain investments, selling assets or transferring revenue, and other similar matters. In addition, the 2016 Term Loan prohibited Amity Oil International Pty Ltd (“Amity”) and Petrogas Petrol Gaz ve Petrokimya Urunleri Insaat Sanayi ve Ticaret A.S. (“Petrogas”) from incurring additional debt. An event of default under the 2016 Term Loan included, among other events, failure to pay principal or interest when due, breach of certain covenants, representations, warranties and obligations, bankruptcy or insolvency and the occurrence of a material adverse effect.

The 2016 Term Loan was secured by a pledge of (i) the stock of TEMI, DMLP, TransAtlantic Turkey and Talon Exploration, (ii) substantially all of the assets of TEMI, (iii) certain real estate owned by Petrogas, (iv) the Gundem real estate and Muratli real estate owned by Gundem Turizm Yatirim ve Isletmeleri A.S. (“Gundem”) and (v) certain Diyarbakir real estate owned 80% by N. Malone Mitchell 3rd and 20% by Selami Erdem Uras. In addition, TEMI assigned its Turkish collection accounts and its receivables from the sale of oil to DenizBank as additional security for the 2016 Term Loan. Gundem is beneficially owned by Mr. Mitchell, his adult children, and Mr. Uras. Mr. Mitchell is our chief executive officer and chairman of our board of directors. Mr. Uras is our vice president, Turkey.

On June 28, 2018, we repaid the 2016 Term Loan in full in accordance with its terms.

2017 Term Loan

On November 17, 2017, DenizBank entered into a $20.4 million term loan (the “2017 Term Loan”) with TEMI under the Credit Agreement. We will use the proceeds from the 2017 Term Loan for general corporate purposes.

The 2017 Term Loan bears interest at a fixed rate of 6.0% (plus 0.3% for Banking and Insurance Transactions Tax per the Turkish government) per annum. The 2017 Term Loan has a grace period which bears no interest or payments due until July 2018 and then is payable in one monthly installment of $1.38 million, nine monthly installments of $1.2 million each through April 2019 and thereafter in eight monthly installments of $1.0 million each through December 2019, with the exception of one monthly installment of $1.2 million occurring in October 2019. The 2017 Term Loan matures in December 2019. Amounts repaid under the 2017 Term Loan may not be re-borrowed, and early repayments under the 2017 Term Loan are subject to early repayment fees. The 2017 Term Loan is guaranteed by Petrogas, Amity, Talon Exploration, DMLP, and TransAtlantic Turkey.

The 2017 Term Loan contains standard prohibitions on the activities of TEMI as the borrower, including prohibitions on granting of liens on its assets, incurring additional debt, dissolving, liquidating, merging, consolidating, paying dividends, making certain investments, selling assets or transferring revenue, and other similar matters. In addition, the 2017 Term Loan prohibits Amity and Petrogas from incurring additional debt. An event of default under the 2017 Term Loan includes, among other events, failure to pay principal or interest when due, breach of certain covenants, representations, warranties and obligations, bankruptcy or insolvency and the occurrence of a material adverse effect.

The 2017 Term Loan is secured by a pledge of (i) the stock of TEMI, DMLP, TransAtlantic Turkey, and Talon Exploration, (ii) substantially all of the assets of TEMI, (iii) certain real estate owned by Petrogas, (iv) the Gundem real estate and Muratli real estate owned by Gundem, (v) certain Diyarbakir real estate owned 80% by N. Malone Mitchell 3rd and 20% Selami Erdem Uras, and (vi) certain Ankara real estate owned 100% by Mr. Uras. In addition, TEMI assigned its Turkish collection accounts and its receivables from the sale of oil to DenizBank as additional security for the 2017 Term Loan. Gundem is beneficially owned by Mr. Mitchell, his adult children, and Mr. Uras. Mr. Mitchell is our chief executive officer and chairman of our board of directors. Mr. Uras is our vice president, Turkey.

At June 30, 2018, we had $20.4 million outstanding under the 2017 Term Loan and no availability, and we were in compliance with the covenants in the 2017 Term Loan.

2018 Term Loan

On May 28, 2018, DenizBank entered into a $10.0 million term loan (the “2018 Term Loan”) with TEMI under the Credit Agreement. We will use the proceeds from the 2018 Term Loan for general corporate purposes.

The 2018 Term Loan bears interest at a fixed rate of 7.25% (plus 0.3% for Banking and Insurance Transactions Tax per the Turkish government) per annum. The 2018 Term Loan has a grace period through July 2018 during which no payments are due. Thereafter, accrued interest on the 2018 Term Loan is payable monthly and the principal on the 2018 Term Loan is payable in five monthly installments of $0.2 million each through December 2018, four monthly installments of $0.5 million each through April 2019, four monthly installments of $1.0 million each through August 2019, and four monthly installments of $0.75 million each through December 2019. The 2018 Term Loan matures in December 2019. Amounts repaid under the 2018 Term Loan may not be reborrowed, and early repayments under the 2018 Term Loan are subject to early repayment fees. The 2018 Term Loan is guaranteed by Petrogas, Amity, Talon Exploration, DMLP, and TransAtlantic Turkey.

The 2018 Term Loan contains standard prohibitions on the activities of TEMI as the borrower, including prohibitions on encumbering or creating restrictions or limitations on all or a part of its assets, revenues, or properties, giving guaranties or sureties, selling assets or transferring revenues, dissolving, liquidating, merging, or consolidating, incurring additional debt, paying dividends, making certain investments, undergoing a change of control, and other similar matters. In addition, the 2018 Term Loan prohibits Amity, Talon

Exploration, DMLP, and Transatlantic Turkey from incurring additional debt. An event of default under the 2018 Term Loan includes, among other events, failure to pay principal or interest when due, breach of certain covenants, representations, warranties, and obligations, bankruptcy or insolvency, and the occurrence of a material adverse effect.

The 2018 Term Loan is secured by a pledge of (i) the stock of TEMI, DMLP, TransAtlantic Turkey, and Talon Exploration, (ii) substantially all of the assets of TEMI, (iii) certain real estate owned by Petrogas, (iv) certain Gundem real estate and Muratli real estate owned by Gundem, (v) certain Diyarbakir real estate owned 80% by N. Malone Mitchell 3rd and 20% Selami Erdem Uras, and (vi) certain Ankara real estate owned 100% by Mr. Uras. In addition, TEMI assigned its Turkish collection accounts and its receivables from the sale of oil to DenizBank as additional security for the 2018 Term Loan. Gundem is beneficially owned by Mr. Mitchell, his adult children, and Mr. Uras. Mr. Mitchell is our chief executive officer and chairman of our board of directors. Mr. Uras is our vice president, Turkey.

At June 30, 2018, we had $10.0 million outstanding under the 2018 Term Loan and no availability, and we were in compliance with the covenants in the 2018 Term Loan.

2017 Notes

Our 13.0% Senior Convertible Notes due 2017 (the “2017 Notes”) were issued pursuant to an indenture, dated as of February 20, 2015 (the “Indenture”), between us and U.S. Bank National Association, as trustee (the “Trustee”). The 2017 Notes bore interest at an annual rate of 13.0%, payable semi-annually, in arrears, on January 1 and July 1 of each year. The 2017 Notes matured on July 1, 2017, and on July 3, 2017, we paid off and retired all remaining outstanding 2017 Notes.

ANBE Note

On December 30, 2015, TransAtlantic Petroleum (USA) Corp (“TransAtlantic USA”) entered into a $5.0 million draw down convertible promissory note (the “ANBE Note”) with ANBE Holdings, L.P. (“ANBE”), an entity owned by the adult children of our chairman and chief executive officer, N. Malone Mitchell 3rd, and controlled by an entity managed by Mr. Mitchell and his wife. The ANBE Note bore interest at a rate of 13.0% per annum. On December 30, 2015, we borrowed $3.6 million under the ANBE Note for general corporate purposes.

On October 31, 2016, TransAtlantic USA entered into an amendment of the ANBE Note with ANBE (the “ANBE Amendment”). The ANBE Amendment extended the maturity date of the Note from October 31, 2016 to September 30, 2017, provided for the ANBE Note to be repaid in four quarterly installments of $0.9 million each in December 2016 and March, June and September 2017, and provided for monthly payments of interest.

On February 27, 2017, we repaid the ANBE Note in full with proceeds from the sale of TBNG and terminated it.

Unsecured lines of credit

Our wholly-owned subsidiaries operating in Turkey are party to unsecured, non-interest bearing lines of credit with a Turkish bank. At June 30, 2018, we had no outstanding borrowings under these lines of credit.

8. Contingencies relating to production leases and exploration permits

Selmo

We are involved in litigation with persons who claim ownership of a portion of the surface at the Selmo oil field in Turkey. These cases are being vigorously defended by TEMI and Turkish governmental authorities. We do not have enough information to estimate the potential additional operating costs we would incur in the event the purported surface owners' claims are ultimately successful. Any adjustment arising out of the claims will be recorded when it becomes probable and measurable.

Bulgaria

During 2012, we were notified that the Bulgarian government may seek to recover approximately $2.0 million in contractual obligations under our Aglen exploration permit work program. Due to the Bulgarian government's January 2012 ban on fracture stimulation and related activities, a force majeure event under the terms of the exploration permit was recognized by the Bulgarian government. Although we invoked force majeure, we recorded $2.0 million in general and administrative expense relating to our Aglen exploration permit during 2012 for this contractual obligation.

In October 2015, the Bulgarian Minister of Energy filed a suit in the Sofia City Court against Direct Petroleum Bulgaria EOOD (“Direct Bulgaria”), claiming $200,000 in liquidated damages for Direct Bulgaria’s alleged failure to fulfill its obligations under the Aglen exploration permit work program. In May 2018, the Sofia City Court concluded that Direct Bulgaria did not fail to fulfill its obligations under the Aglen exploration permit work program as Direct Bulgaria received a force majeure event recognition as a result of a fracture stimulation ban in 2012, imposed by the Bulgarian Parliament, which force majeure event had not been terminated before the expiry of Direct Bulgaria’s obligations under the Aglen exploration permit work program. Additionally, the Sofia City Court concluded that, even if Direct Bulgaria had failed to fulfill its obligations under the Aglen exploration permit work program, the Bulgarian Minister of Energy failed to file suit within the three-year limitation period. Therefore, the Sofia City Court dismissed all claims of the Bulgarian Minister of Energy and ordered the Bulgarian Minister of Energy to pay Direct Bulgaria’s attorney’s fees and legal costs for court experts. In June 2018, the Bulgarian Minister of Energy filed an appeal in the Sofia Court of Appeal. We continue to vigorously defend this claim.

9. Shareholders’ equity

Restricted stock units

We recorded share-based compensation expense of $0.1 million and $0.3 million for awards of restricted stock units (“RSUs”) for the three months ended June 30, 2018 and 2017, respectively. We recorded share-based compensation expense of $0.2 million and $0.4 million for awards of RSUs for the six months ended June 30, 2018 and 2017, respectively.

As of June 30, 2018, we had approximately $0.5 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 0.7 years.

Earnings per share

We account for earnings per share in accordance with ASC Subtopic 260-10, Earnings Per Share (“ASC 260-10”). ASC 260-10 requires companies to present two calculations of earnings per share: basic and diluted. Basic earnings per common share for the three and six months ended June, 2018 and 2017 equals net loss divided by the weighted average shares outstanding during the periods. Weighted average shares outstanding are equal to the weighted average of all shares outstanding for the period, excluding unvested RSUs. Diluted earnings per common share for the three and six months ended June 30, 2018 and 2017 are computed in the same manner as basic earnings per common share after assuming the issuance of common shares for all potentially dilutive common share equivalents, which includes RSUs, preferred shares and warrants (prior to January 6, 2018), whether exercisable or not. For the three and six months ended June 30, 2018, there were no dilutive securities included in the calculation of diluted earnings per share.

The following table presents the basic and diluted earnings per common share computations:

(in thousands, except per share amounts)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Net (loss) earnings from continuing operations	$(1,006)	$566	$(2,781)	$(15,483)

Basic net (loss) earnings per common share:				
Shares:				
Weighted average common shares outstanding	50,420	47,412	50,397	47,355
Basic net (loss) earnings per common share:				
Continuing operations	$(0.02)	$0.01	$(0.06)	$(0.33)
Diluted net (loss) earnings per common share:				
Shares:				
Weighted average common shares outstanding	50,420	47,826	50,397	47,355
Diluted net (loss) earnings per common share:				
Continuing operations	$(0.02)	$0.01	$(0.06)	$(0.33)

Warrants

On December 31, 2014, April 24, 2015 and August 13, 2015, we issued 233,334, 233,333 and 233,333 common share purchase warrants (“Warrants”), respectively, to the shareholders of Gundem as consideration for the pledge of Turkish real estate in exchange for an extension of the maturity of a credit agreement between us and a Turkish bank. As consideration for the pledge of Turkish real estate, the independent members of our board of directors approved the issuance of the Warrants to be allocated in accordance with each shareholder's ownership percentage of Gundem. The Warrants were issued pursuant to a warrant agreement, whereby the Warrants were immediately exercisable and entitled the holder to purchase one common share for each Warrant. The Warrants were issued in December 2014, April 2015 and August 2015 at an exercise price of $5.99, $5.65 and $2.99 per share, respectively. The Warrants expired, unexercised, pursuant to their terms on January 6, 2018.

10. Segment information

In accordance with ASC 280, Segment Reporting ("ASC 280"), we have two reportable geographic segments: Turkey and Bulgaria. Summarized financial information from continuing operations concerning our geographic segments is shown in the following table:

	Corporate	Turkey	Bulgaria	Total
	(in thousands)			
For the three months ended June 30, 2018				
Total revenues	$-	$18,198	$ -	$18,198
(Loss) income from continuing operations before income taxes	$(4,429)	4,612	$ (75)	108
Capital expenditures	$-	$5,625	$ -	$5,625
For the three months ended June 30, 2017				
Total revenues	$-	$12,341	$ -	$12,341
(Loss) income from continuing operations before income taxes	(4,315)	6,163	(79)	1,769
Capital expenditures	$-	$4,893	$ -	$4,893
For the six months ended June 30, 2018				
Total revenues	$-	$35,124	$ -	$35,124
(Loss) income from continuing operations before income taxes	$(8,222)	$7,963	$ (121)	$(380)
Capital expenditures	$-	$10,835	$ -	$10,835
For the six months ended June 30, 2017				
Total revenues	$-	$28,777	$ -	$28,777
(Loss) income from continuing operations before income taxes	(23,236)	11,240	(149)	(12,145)
Capital expenditures	$-	$11,331	$ -	$11,331
Segment assets				
June 30, 2018	$10,890	$136,107	$ 795	$147,792
December 31, 2017	$10,966	$149,185	$ 499	$160,650

11. Financial instruments

Interest rate risk

We are exposed to interest rate risk as a result of our variable rate short-term cash holdings.

Foreign currency risk

We have underlying foreign currency exchange rate exposure. Our currency exposures primarily relate to transactions denominated in the Bulgarian Lev, the European Union Euro, and the New Turkish Lira (“TRY”). We are also subject to foreign currency exposures resulting from translating the functional currency of our subsidiary financial statements into the U.S. Dollar reporting currency. At June 30, 2018, we had 1.0 million TRY (approximately $0.2 million) in cash and cash equivalents, which exposes us to exchange rate risk based on fluctuations in the value of the TRY. We have not used foreign currency forward contracts to manage exchange rate fluctuations prior to 2018. At June 30, 2018, we were a party to foreign exchange derivative contracts (See Note 6. “Derivative instruments”).

Commodity price risk

We are exposed to fluctuations in commodity prices for oil and natural gas. Commodity prices are affected by many factors, including, but not limited to, supply and demand. At June 30, 2018 and December 31, 2017, we were a party to commodity derivative contracts (See Note 6. “Derivative instruments”).

Concentration of credit risk

The majority of our receivables are within the oil and natural gas industry, primarily from our industry partners and from government agencies. Included in receivables are amounts due from Turkiye Petrolleri Anonim Ortakligi ("TPAO"), the national oil company of Turkey, Zorlu Dogal Gaz Ithalat Ihracat ve Toptan Ticaret A.S. ("Zorlu"), a privately owned natural gas distributor in Turkey, and TUPRAS, which purchase the majority of our oil and natural gas production. The receivables are not collateralized. To date, we have experienced minimal bad debts and have no allowance for doubtful accounts for TUPRAS. The majority of our cash and cash equivalents are held by four financial institutions in the United States and Turkey.

Fair value measurements

Cash and cash equivalents, restricted cash, accounts receivable, accounts payable, accrued liabilities and our loans payable were each estimated to have a fair value approximating the carrying amount at June 30, 2018 and December 31, 2017, due to the short maturity of those instruments.

The following table summarizes the valuation of our financial assets and liabilities as of June 30, 2018:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Measured on a recurring basis				
Liabilities:				
Foreign exchange derivative contracts	$-	$ (1,324)	$ -	(1,324)
Commodity derivative contracts	-	(1,558)	-	(1,558)
Disclosed but not carried at fair value				
Liabilities:				
2018 Term Loan	-	-	(8,493)	(8,493)
2017 Term Loan	-	-	(18,035)	(18,035)
2016 Term Loan	-	-	-	-
Total	$-	$ (2,882)	$ (26,528)	$(29,410)

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2017:

Fair Value Measurement Classification

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Measured on a recurring basis				
Liabilities:				
Commodity derivative contracts	$-	$ (2,215)	$ -	$(2,215)
Disclosed but not carried at fair value				
Liabilities:				
2017 Term Loan	-	-	(16,613)	(16,613)
2016 Term Loan	-	-	(7,866)	(7,866)
Total	$-	$ (2,215)	$ (24,479)	$(26,694)

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We remeasure our derivative contracts on a recurring basis, with changes flowing through earnings. At June 30, 2018 and December 31, 2017, the fair values of the 2018 Term Loan, 2017 Term Loan, and the 2016 Term Loan were estimated using a discounted cash flow analysis based on unobservable Level 3 inputs, including our own credit risk associated with the loans payable.

12. Related party transactions

The following table summarizes related party accounts receivable and accounts payable as of the dates indicated:

	June 30, 2018	December 31, 2017
	(in thousands)	
Related party accounts receivable:		
Riata Management Service Agreement	$704	$ 576
PSIL MSA	449	447
Total related party accounts receivable	$1,153	$ 1,023
Related party accounts payable:		
Riata Management Service Agreement	$672	$ 341
PSIL MSA	2,213	2,119
Interest payable on Series A Preferred	378	681
Other - board of directors fees	125	-
Total related party accounts payable	$3,388	$ 3,141

Services transactions

Effective May 1, 2008, we entered into a service agreement (as amended, the “Service Agreement”), with Longfellow Energy, LP (“Longfellow”), Viking Drilling LLC (“Viking Drilling”), MedOil Supply, LLC and Riata Management, LLC (“Riata Management”) (collectively, the “Service Entities”). Mr. Mitchell and his wife own 100% of Riata Management. In addition, Mr. Mitchell, his wife and his children indirectly own 100% of Longfellow. Riata Management owns 100% of MedOil Supply, LLC. Dalea Partners, LP (“Dalea”), an affiliate of Mr. Mitchell, owns 100% of Viking Drilling. Under the terms of the Service Agreement, we pay, or are paid, for the actual cost of the services rendered plus the actual cost of reasonable expenses on a monthly basis. Under the terms of the Service Agreement, the Service Entities agreed to provide us upon our request certain computer services, payroll and benefits services, insurance administration services and entertainment services, and we and the Service Entities agreed to provide to each other certain management consulting services, oil and natural gas services and general accounting services (collectively, the “Services”). Under the terms of the Service Agreement, we pay, or are paid, for the actual cost of the Services rendered plus the actual cost of reasonable expenses on a monthly basis. We or the Service Entities may terminate the Service Agreement at any time by providing advance notice of termination to the other party.

On March 20, 2017, we entered into a second amendment to the Service Agreement among us and Longfellow, Viking Drilling, Riata Management, Longfellow Nemaha, LLC, a Texas limited liability company, Red Rock

Minerals, LP, a Delaware limited partnership, Red Rock Advisors, LLC, a Texas limited liability company, Production Solutions International Limited, a Bermuda exempted company, and Nexlube Operating, LLC, a Delaware limited liability company, and their subsidiaries (collectively, the “Riata Entities”), adding and removing certain of the Service Entities and the Riata Entities and expanding the scope of Services. As this agreement is a related party transaction, the independent members of our board of directors reviewed and approved this amendment.

As of June 30, 2018, we had $0.7 million of outstanding receivables and $0.7 million of outstanding payables pursuant to the Service Agreement.

On March 3, 2016, Mr. Mitchell closed a transaction whereby he sold his interests in Viking Services B.V. ("Viking Services"), the beneficial owner of Viking International Limited ("Viking International"), Viking Petrol Sahasi Hizmetleri A.S. ("VOS") and Viking Geophysical Services Ltd. ("Viking Geophysical"), to a third party. As part of the transaction, Mr. Mitchell acquired certain equipment used in the performance of stimulation, wireline, workover and similar services, which equipment is owned and operated by Production Solutions International Petrol Arama Hizmetleri Anonim Sirketi ("PSIL"). PSIL is beneficially owned by Dalea Investment Group, LLC, which is controlled by Mr. Mitchell. Consequently, on March 3, 2016, TEMI entered into a master services agreement (the "PSIL MSA") with PSIL on substantially similar terms to our then current master services agreements with Viking International, VOS and Viking Geophysical. Pursuant to the PSIL MSA, PSIL performs the services on behalf of TEMI and its affiliates. The master services agreement with each of Viking International, VOS and Viking Geophysical currently remain in effect.

As of June 30, 2018, we had $0.4 million of outstanding receivables and $2.2 million of outstanding payables pursuant to the PSIL MSA.

Office sublease

On August 7, 2018 and effective as of June 14, 2018, TransAtlantic USA entered into a sublease agreement (the "Sublease") with Longfellow to lease corporate office space located at 16803 North Dallas Parkway, Addison, Texas. The Sublease was approved by the audit committee of the board of directors.

TransAtlantic USA subleases approximately 10,000 square feet of corporate office space in Addison, Texas. The initial lease term under the Sublease commenced on June 14, 2018 (the "Commencement Date") and expires on June 30, 2020, unless earlier terminated in accordance with the Sublease. From the Commencement Date until June 30, 2019, TransAtlantic USA is required to pay monthly rent of $18,333.33 to Longfellow, plus utilities, real property taxes, and liability insurance (to the extent that TransAtlantic USA does not obtain its own liability insurance). The monthly rent increases by $416.67 for the period commencing June 30, 2019 and ending June 30, 2021.

Pursuant to the Sublease, effective as of June 14, 2018, TransAtlantic USA and Longfellow agreed to terminate the Amended and Restated Office Lease, dated June 26, 2017, by and between TransAtlantic USA and Longfellow.

Dalea Amended Note and Pledge Agreement

On April 19, 2016, we entered into a note amendment agreement (the "Note Amendment Agreement") with Mr. Mitchell, and Dalea Partners, LP ("Dalea"), pursuant to which Dalea agreed to deliver an amended and restated promissory note (the "Amended Note") in favor of us, in the principal sum of $7,964,053, which Amended Note would amend and restate that certain Promissory Note, dated June 13, 2012, made by Dalea in favor of us in the principal amount of $11.5 million (the "Original Note"). The Note Amendment Agreement reduced the principal amount of the Original Note to $7,964,053 in exchange for the cancellation of an account payable of approximately $3.5 million (the "Account Payable") owed by TransAtlantic Albania Ltd. ("TransAtlantic Albania"), our former subsidiary, to Viking International Limited. We have indemnified a third party for any liability relating to the payment of the Account

Payable.

Pursuant to the Note Amendment Agreement, on April 19, 2016, we entered into the Amended Note, which amended and restated the Original Note that was issued in connection with our sale of our subsidiaries, Viking International and Viking Geophysical Services, to a joint venture owned by Dalea and Abraaj Investment Management Limited in June 2012. In the Amended Note, we and Dalea acknowledged that (i) while the sale of Dalea's interest in Viking Services enabled us to take the position that the Original Note was accelerated in accordance with its terms, the principal purpose of including the acceleration events in the Original Note was to ensure that certain oilfield services provided by Viking Services to us would continue to be available to us, and (ii) such services will now be provided pursuant to the PSIL MSA. PSIL is beneficially owned by Dalea Investment Group, LLC, which is controlled by Mr. Mitchell. As a result, the Amended Note revised the events triggering acceleration of the repayment of the Original Note to the following: (i) a reduction of ownership by Dalea (and other controlled affiliates of Mr. Mitchell) of equity interest in PSIL to less than 50%; (ii) the sale or transfer by Dalea or PSIL of all or substantially all of its assets to any person (a "Transferee") that does not own a controlling interest in Dalea or PSIL and is not controlled by Mr. Mitchell (an "Unrelated Person"), or the subsequent transfer by any Transferee that is not an Unrelated Person of all or substantially all of its assets to an Unrelated Person; (iii) the acquisition by an Unrelated Person of more than 50% of the voting interests of Dalea or PSIL; (iv) termination of the PSIL MSA other than as a result of an uncured default thereunder by TEMI; (v) default by PSIL under the PSIL MSA, which default is not remedied within a period of 30 days after notice thereof to PSIL; and (vi) insolvency or bankruptcy of PSIL. The maturity date of the Amended Note was extended to June 13, 2019. The interest rate on the Amended Note remains at 3.0% per annum and continues to be guaranteed by Mr. Mitchell. The Amended Note contains customary events of default.

In addition, pursuant to the Note Amendment Agreement, on April 19, 2016, we entered into a pledge agreement (the “Pledge Agreement”) with Dalea, whereby Dalea pledged the $2.0 million principal amount of the 2017 Notes owned by Dalea (the “Dalea Convertible Notes”), including any future securities for which the Dalea Convertible Notes are converted or exchanged, as security for the performance of Dalea’s obligations under the Amended Note. The Pledge Agreement provides that interest payable to Dalea under the Dalea Convertible Notes (or any future securities for which the Dalea Convertible Notes are converted or exchanged) will be credited first against the outstanding principal balance of the Amended Note and, upon full repayment of the outstanding principal balance of the Amended Note, any accrued and unpaid interest on the Amended Note. The Pledge Agreement contains customary events of default. On November 4, 2016, Dalea exchanged $2.0 million of 2017 Notes for 40,000 Series A Preferred Shares.

On June 30, 2016, we entered into a waiver with Dalea, whereby we waived our right under the Pledge Agreement to receive the interest payment due July 1, 2016 under the Dalea Convertible Notes in connection with the payment of 201,459 common shares to Dalea with respect to the 2017 Note interest payment paid on June 30, 2016.

During the three and six months ended June 30, 2018, we reduced the principal amount of the Amended Note by $0.1 million and $0.1 million, respectively, for cash dividends paid on the Series A Preferred Shares.

As of June 30, 2018, the amount receivable under the Amended Note was $6.3 million.

Pledge fee agreements

In connection with the pledge of the Gundem real estate and Muratli real estate to DenizBank as collateral for the 2016 Term Loan, on August 31, 2016, we entered into a pledge fee agreement with Gundem (the “Gundem Fee Agreement”) pursuant to which we pay Gundem a fee equal to 5% per annum of the collateral value of the Gundem real estate and Muratli real estate. Pursuant to the Gundem Fee Agreement, the Gundem real estate has a deemed collateral value of $10.0 million and the Muratli real estate has a deemed collateral value of $5.0 million.

In connection with the pledge of the Diyarbakir real estate to DenizBank as collateral for the 2016 Term Loan, on August 31, 2016, we entered into a pledge fee agreement with Messrs. Mitchell and Uras (the “Diyarbakir Fee Agreement”) pursuant to which we pay Mr. Mitchell and Selami Erdem Uras a fee of 5% per annum of the collateral value of the Diyarbakir real estate. Mr. Uras is our vice president, Turkey. Pursuant to the Diyarbakir Fee Agreement, the Diyarbakir real estate has a deemed collateral value of $5.0 million.

Amounts payable to Mr. Mitchell under the Gundem Fee Agreement and the Diyarbakir Fee Agreement are used to reduce the outstanding principal amount of the Amended Note. During the three and six months ended June 30, 2018, we reduced the principal amount of the Amended Note by $0.2 million and $0.3 million, respectively, for amounts payable under the pledge fee agreements.

13. Assets and liabilities held for sale and discontinued operations

TBNG assets and liabilities held for sale

On October 13, 2016, we entered into a share purchase agreement (the "Purchase Agreement") with Valeura Energy Netherlands B.V. ("Valeura Netherlands") for the sale of all of the equity interests in TBNG, our wholly-owned subsidiary. TBNG owned a portion of our interests in the Thrace Basin area in Turkey.

We classified the assets and liabilities of TBNG within the captions "Assets held for sale" and "Liabilities held for sale" on our consolidated balance sheets as of December 31, 2016. Although the sale of TBNG met the threshold to classify its assets and liabilities as held for sale, it didn't meet the requirements to classify its operations as discontinued as the sale wasn't considered a strategic shift in our operations. As such, TBNG's results of operations are classified as continuing operations for all periods presented.

On February 24, 2017, we closed on the sale of TBNG for gross proceeds of $20.7 million, and approximate net cash proceeds of $16.1 million, which amounts reflect a $0.2 million post-closing purchase price adjustment.

For the three months March 31, 2017, we recorded a non-cash net loss of $15.2 million on the sale of TBNG. The loss related to the reclassification of the TBNG accumulated foreign currency translation adjustment that was realized into earnings from accumulated other comprehensive loss within shareholders' equity, and presented below:

	Loss on Sale (in thousands)
Total cash proceeds for TBNG	$ 20,707
Less: TBNG net assets	12,869
Gain on sale before accumulated foreign currency translation adjustment	7,838
Less: TBNG accumulated foreign currency translation adjustment	(23,064)
Net loss on sale of TBNG	$ (15,226)

As a result of the TBNG sale, there were no assets or liabilities held for sale as of December 31, 2017 or as of June 30, 2018. For the three and six months ended June 30, 2018 and 2017, we had no significant operating results from discontinued operations.

14. Subsequent Events

On August 7, 2018 and effective as of June 14, 2018, TransAtlantic USA entered into the Sublease with Longfellow to lease corporate office space located at 16803 North Dallas Parkway, Addison, Texas (See Note 12. “Related party transactions”).

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

In this Quarterly Report on Form 10-Q, references to "we," "our," "us" or the "Company," refer to TransAtlantic Petroleum Ltd. and its subsidiaries on a consolidated basis unless the context requires otherwise. Unless stated otherwise, all sums of money stated in this Quarterly Report on Form 10-Q are expressed in U.S. Dollars.

Executive Overview

We are an international oil and natural gas company engaged in acquisition, exploration, development, and production. We have focused our operations in countries that have established, yet underexplored petroleum systems, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates, and tax rates to exploration and production companies. As of June 30, 2018, we held interests in approximately 343,000 and 163,000 net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria, respectively. As of August 6, 2018, approximately 47% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, our chief executive officer and chairman of our board of directors.

We are a holding company with two operating segments – Turkey and Bulgaria. Our assets consist of our ownership interests in subsidiaries that primarily own assets in Turkey and Bulgaria.

Strategic Alternatives Process

On January 16, 2018, we announced the formation of a special committee of the board of directors to market the Company and explore strategic alternatives to increase shareholder value. Since that time, the special committee has received several proposals to acquire the Company or certain of its assets. Following evaluation of the proposals, the special committee is currently in discussions with a potential acquiror of the entire Company and expects to receive a formal offer from such party and begin negotiating a letter of intent within the next 30 days. There is no assurance that we will receive an offer or enter into any agreement with such party. We will provide a further update at the appropriate time.

Financial and Operational Performance Summary

The following summarizes our financial and operational performance for the second quarter of 2018:

- We reported a $1.0 million net loss from continuing operations for the three months ended June 30, 2018.
  - We derived 98.2% of our oil and natural gas revenues from the production of oil and 1.5% from the production of natural gas during the three months ended June 30, 2018.
- Total oil and natural gas sales revenues increased 47.4% to $18.1 million for the quarter ended June 30, 2018 from $12.3 million in the same period in 2017. The increase was the result of a $31.62 increase in the average price received per barrel of oil equivalent ("Boe") as well as the adoption of ASU 2014-09, which now requires transportation costs, previously netted in revenue, to be reported separately.
- For the quarter ended June 30, 2018, we incurred $5.6 million in capital expenditures, including seismic and corporate expenditures, as compared to $4.9 million for the quarter ended June 30, 2017.
- As of June 30, 2018, we had $11.2 million in long-term debt, $19.2 million in short-term debt, and $46.1 million in Series A Preferred Shares as compared to $13.0 million in long-term debt, $15.6 million in short-term debt, and $46.1 million in Series A Preferred Shares as of December 31, 2017. During the quarter ended June 30, 2018, we repaid $4.2 million in debt and obtained a $10.0 million term loan.

Second Quarter 2018 Operational Update

During the second quarter of 2018, we spud one well and continued workover and recompletion production optimizations in southeastern Turkey.

In January 2018, we announced a planned drilling program in Southeast Turkey. This drilling program consisted of a six-well development program in the Selmo field and a two-well development program in the Molla area. Due to our recent success with the Yeniev-1 well, the increase in oil prices over the past six months, and optimism regarding the potential of our licenses in the Thrace Basin BCGA, we adjusted our drilling program and capital expenditure allocations for the remainder of 2018.

The following summarizes our operations by location during the second quarter of 2018 and our drilling plans by location for the remainder of 2018:

Southeastern Turkey

Selmo

In the second quarter of 2018, we vertically completed the Selmo-81H2 well and established commercial production of 68 barrels of oil per day (“Bopd”).

Workover and recompletion production optimizations in the Selmo field are ongoing, but we do not expect to drill additional wells in the Selmo field in the second half of 2018.

Molla

Bahar

We spud the Bahar-8 well targeting the Bedinan, Hazro, and Mardin formations in June 2018 and completed drilling and casing the well in July 2018. Oil shows were observed in all targeted zones. We expect to complete the Bahar-8 well in the third quarter of 2018.

After drilling the Bahar-8 well, we moved the rig to the Bahar-10 well location and spud the Bahar-10 well on August 5, 2018. In the fourth quarter of 2018, we plan to drill an additional well on the southeastern flank of the Bahar field to test the Dadas Sand, Mardin, and Bedinan formations.

Other

In the second quarter of 2018, we drilled the Yeniev-1 well to a total depth of 10,306 feet. Oil shows while drilling and log analysis indicate prospective pay in the Bedinan, Hazro, and Mardin formations. We perforated the first zone in the Bedinan formation on June 28, 2018. The initial production rate for this zone was 730 Bopd from a 24/64 choke and the current production rate is 375 Bopd from a 16/64 choke.

The Yeniev-1 well is a discovery on a new structure in the Molla area, opening up potentially significant drilling locations and potentially leading to additional development drilling. We expect to drill two additional wells to further delineate this structure in the second half of 2018.

We continue testing the Cavuslu-1 well following the discovery of hydrocarbons in the Bedinan and Dadas formations. We recently completed the Mardin zone at 25-40 Bopd after acid stimulation. We will test this isolated zone for approximately 30 days. Following this testing, we expect to begin long-term production in one or more of the tested zones.

On June 12, 2018, we were awarded a production license for the M44-b2-1 block, which covers 37,700 acres contiguous to our acreage in West Molla. This license includes our Catak, Pinar, and Yeniev wells.

We expect to fracture stimulate the Bedinan formation in the Pinar-1 well during the third quarter of 2018.

We have completed the 3D seismic processing and initial interpretation of our East Molla 3D seismic and have identified several prospects, which we expect to drill in the first half of 2019, contingent on financing.

Northwestern Turkey

Thrace Basin

Thrace Basin BCGA

We continue to evaluate our prospects in the Thrace Basin BCGA in light of the recent positive production test results at the Yamalik-1 exploration well operated by Valeura Energy Inc. (“Valeura”) with their partner Equinor ASA (formerly Statoil ASA) (“Equinor”). The Yamalik-1 exploration well is located on a license directly adjacent to our 120,000 net acres in the Thrace Basin of which we believe approximately 50,000 net acres (100% working interest, 87.5% net revenue interest) is in the Thrace Basin BCGA and analogous to the Valeura and Equinor acreage. We expect to spud the Karli-1 well, a gas exploration well in the Thrace Basin BCGA, in the fourth quarter of 2018. We will test zones and depths at the Karli-1 well equivalent to those tested at the Yamilik-1 well.

Other

We expect to resume production operations on the Yildurm-1 well in the second half of 2018

Bulgaria

We have prepared plans to side track and re-drill the Devinci R-1 well, which we plan to commence in the third quarter of 2018.

Planned Operations

In connection with our revised 2018 drilling program, we increased our projected remaining 2018 capital expenditure budget from our prior estimates. We now expect our net field capital expenditures for the remainder of 2018 to range between $24.0 million and $28.0 million. We expect net field capital expenditures during the remainder of 2018 to include between $20.0 million and $26.0 million in drilling and completion expense and approximately $1.2 million in recompletion expense.

We expect that cash on hand and cash flow from operations will be sufficient to fund the remainder of our 2018 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected remaining 2018 capital expenditure budget is subject to change.

Significant Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosures. Our significant accounting policies are described in “Note 3. Significant accounting policies” to our audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2017 and are of particular importance to the portrayal of our financial position and results of operations and require the application of significant judgment by management. These estimates are based on historical experience, information received from third parties, and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

Effective January 1, 2018, we adopted new accounting standards for revenue, statement of cash flows and restricted cash disclosures in statement of cash flows (See Note 2. “Recent accounting pronouncements”).

Results of Operations—Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

Our results of operations for the three months ended June 30, 2018 and 2017 were as follows:

	Three Months Ended June 30, 2018	2017	Change 2018-2017
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	241	290	(49)
Natural gas (Mmcf)	56	66	(10)
Total production (Mboe)	250	301	(51)
Average daily sales volumes (Boepd)	2,746	3,308	(562)
Average prices:			
Oil (per Bbl)	$ 74.10	$ 41.27	$ 32.83
Natural gas (per Mcf)	$ 4.84	$ 4.77	$ 0.07
Oil equivalent (per Boe)	$ 72.42	$ 40.80	$ 31.62
Revenues:			
Oil and natural gas sales	$ 18,100	$ 12,283	$ 5,817
Sales of purchased natural gas	1	-	1
Other	97	58	39
Total revenues	18,198	12,341	5,857
Costs and expenses (income):			
Production	2,803	2,714	89
Transportation and processing	1,138	-	1,138
Exploration, abandonment and impairment	191	2	189
Cost of purchased natural gas	1	-	1
Seismic and other geological and geophysical	59	65	(6)
General and administrative	3,786	3,181	605
Depletion	3,039	4,004	(965)
Depreciation and amortization	237	251	(14)
Interest and other expense	2,091	2,288	(197)
Interest and other income	(377)	(188)	(189)
Foreign exchange loss (gain)	1,938	(1,116)	3,054
Gain (loss) on derivative contracts:			
Cash settlements on derivative contracts	(1,860)	32	(1,892)
Change in fair value on derivative contracts	(1,281)	644	(1,925)
Total (loss) gain on derivative contracts	(3,141)	676	(3,817)
Oil and natural gas costs per Boe:			
Production	$ 9.18	$ 7.89	$ 1.29
Depletion	$ 10.64	$ 11.64	$ (1.00)

Oil and Natural Gas Sales. Total oil and natural gas sales revenues increased to $18.1 million for the three months ended June 30, 2018 from $12.3 million for the same period in 2017. The increase was primarily due to an increase in the average realized price per Boe. Our average price received increased $31.62 per Boe to $72.42 per Boe for the three months ended June 30, 2018 from $40.80 per Boe for the same period in 2017. This was partially offset by a decrease in our average daily sales volumes of 562 Boepd for the three months ended June 30, 2018 as compared to the same period in 2017. In addition, the increase was a result of a new revenue reporting regulation, ASU 2014-09, adopted in 2018 requiring previously netted transportation expenses, of $1.1 million for the three months ended June 30, 2018, to be reported separately as expenses.

Sales of Purchased Natural Gas. Sales of purchased natural gas for the three months ended June 30, 2018 did not change significantly from the same period in 2017.

Production. Production expenses increased to $2.8 million, or $9.18 per Boe, for the three months ended June 30, 2018 from $2.7 million, or $7.89 per Boe, for the same period in 2017. The increase was primarily due to more workovers during the three months ended June 30, 2018 as compared to the same period in 2017.

Transportation and Processing. Transportation and processing expense increased to $1.1 million for the three months ended June 30, 2018 from zero for the same period in 2017. The increase was due to the new revenue reporting regulation, ASU 2014-09, which now requires this cost, previously netted in revenue, to be reported separately.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment cost increased to $0.2 million for the three months ended June 30, 2018 from $2,000 for the same period in 2017. The increase was primarily due to additional impairments recorded in the Redy and Edirne fields and an additional abandonment expense recorded in the Goksu field for the three months ended June 30, 2018.

General and Administrative. General and administrative expense increased to $3.8 million for the three months ended June 30, 2018 from $3.2 million for the same period in 2017. The increase was primarily due to $0.6 million in costs associated with our strategic alternatives process, which includes professional expenses and travel.

Depletion. Depletion expense decreased to $3.0 million, or $10.64 per Boe, for the three months ended June 30, 2018 from $4.0 million, or $11.64 per Boe, for the same period of 2017. The decrease was primarily due to a devaluation of the Turkish Lira to the US Dollar.

Interest and Other Expense. Interest and other expense decreased to $2.1 million for the three months ended June 30, 2018 from $2.3 million for the same period in 2017. The decrease was primarily due to our lower average debt balances during the three months ended June 30, 2018 as compared to the same period in 2017.

Interest and Other Income. Interest and other income cost increased to $0.4 million for the three months ended June 30, 2018 from $0.2 million for the same period in 2017. The increase was primarily due to higher average cash balances during the three months ended June 30, 2018 as compared to the same period in 2017.

Foreign Exchange Loss (Gain). We recorded a foreign exchange loss of $1.9 million for the three months ended June 30, 2018 as compared to a gain of $1.1 million for the same period in 2017. Foreign exchange gains and losses are primarily unrealized (non-cash) in nature and results from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the Turkish Lira amount if it has not been settled previously. The foreign exchange loss for the three months ended June 30, 2018 was due to a decrease in the value of the Turkish Lira compared to the U.S. Dollar. From June 30, 2017 to June 30, 2018, the Turkish Lira to the U.S. Dollar declined 30.0%. At June 30, 2018, the exchange rate was 4.5607 as compared to 3.5071 at June 30, 2017.

Gain (Loss) on Derivative Contracts. We recorded a net loss on derivative contracts of $3.1 million for the three months ended June 30, 2018 as compared to a net gain of $0.7 million for the same period in 2017. During the three months ended June 30, 2018, we recorded a $1.3 million loss to mark our currency derivative contracts to their fair value, a $75,000 gain to mark our commodity derivative contracts to their fair value and a $1.9 million loss on settled contracts. During the same period in 2017, we recorded a $0.6 million gain to mark our commodity derivative contracts to their fair value and a $32,000 gain on settled contracts.

Results of Operations—Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Our results of operations for the six months ended June 30, 2018 and 2017 were as follows:

	Six Months Ended June 30,		Change
	2018	2017	2018-2017
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	489	604	(115)
Natural gas (Mmcf)	123	251	(128)
Total production (Mboe)	510	646	(136)
Average daily sales volumes (Boepd)	2,800	3,550	(750)
Average prices:			
Oil (per Bbl)	$69.84	$44.39	$ 25.45
Natural gas (per Mcf)	$4.92	$4.91	$ 0.01
Oil equivalent (per Boe)	$68.22	$43.42	$ 24.80
Revenues:			
Oil and natural gas sales	$34,761	$28,051	$ 6,710
Sales of purchased natural gas	1	654	(653)
Other	362	72	290
Total revenues	35,124	28,777	6,347
Costs and expenses (income):			
Production	5,672	5,801	(129)
Transportation and processing	2,331	-	2,331
Exploration, abandonment and impairment	231	108	123
Cost of purchased natural gas	1	568	(567)
Seismic and other geological and geophysical	218	80	138
General and administrative	7,123	6,771	352
Depletion	7,350	8,315	(965)
Depreciation and amortization	385	437	(52)
Interest and other expense	4,873	4,659	214
Interest and other income	(631)	(481)	(150)
Foreign exchange loss	3,996	1,007	2,989
Gain (loss) on derivative contracts:			
Cash settlements on derivative contracts	(3,200)	32	(3,232)
Change in fair value on derivative contracts	(667)	1,632	(2,299)
Total (loss) gain on derivative contracts	(3,866)	1,664	(5,530)
Oil and natural gas costs per Boe:			
Production	$9.74	$7.81	$ 1.93
Depletion	$12.62	$11.26	$ 1.36

Oil and Natural Gas Sales. Total oil and natural gas sales revenues increased to $34.8 million for the six months ended June 30, 2018 from $28.1 million for the same period in 2017. The increase was primarily due to an increase in the average realized price per Boe. Our average price received increased $24.80 per Boe to $68.22 per Boe for the six months ended June 30, 2018, from $43.42 per Boe for the same period in 2017. This was partially offset by a decrease in our sales volumes of 136 Mboe for the six months ended June 30, 2018 as compared to the same period in 2017, primarily due to a decrease from the divestiture of TBNG in February 2017. In addition, the increase was a result of a new revenue reporting regulation, ASU 2014-09, adopted in 2018 requiring previously netted transportation expenses, of $2.3 million for the six months ended June 30, 2018, to be reported separately as expenses.

Sales of Purchased Natural Gas. Sales of purchased natural gas decreased to $1,000 for the six months ended June 30, 2018 from $0.7 million for the same period in 2017. The decrease was primarily due to the divestiture of TBNG in February 2017.

Production. Production expenses decreased to $5.7 million, or $9.74 per Boe, for the six months ended June 30, 2018 from $5.8 million, or $7.81 per Boe, for the same period in 2017. The decrease in production expense was primarily due to the divestiture of

TBNG in February 2017. The increase in Boe was due to a 21.05% decrease in production volumes as compared to a 2.22% decrease in production expense.

Transportation and Processing. Transportation and processing expense increased to $2.3 million for the six months ended June 30, 2018 from zero for the same period in 2017. The increase was due to the new revenue reporting regulation, ASU 2014-09, which now requires this cost, previously netted in revenue, to be reported separately.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs increased to $0.2 million for the six months ended June 30, 2018 from $0.1 million for the same period in 2017. The increase was primarily due to additional impairments recorded for the six months ended June 30, 2018.

Cost of Purchased Natural Gas. Cost of purchased natural gas decreased to zero for the six months ended June 30, 2018 from $0.6 million for the same period in 2017. The decrease was primarily due to the divestiture of TBNG in February 2017.

General and Administrative. General and administrative expense increased to $7.1 million for the six months ended June 30, 2018 from $6.8 million for the same period in 2017. The increase was primarily due to $0.9 million in costs associated with our strategic alternatives process, which includes professional expenses and travel. This was partially offset by a decrease in insurance expenses of $0.2 million and a decrease in severance and legal contingencies of $0.3 million.

Depletion. Depletion expense decreased to $7.4 million, or $12.62 per Boe, for the six months ended June 30, 2018 from $8.3 million, or $11.26 per Boe, for the same period of 2017. The decrease in depletion expense was primarily due to a devaluation of the Turkish Lira to the US Dollar. The increase in Boe was due to a 21.05% decrease in production volumes as compared to a 11.61% decrease in depletion expense.

Interest and Other Expense. Interest and other expense increased to $4.9 million for the six months ended June 30, 2018 from $4.7 million for the same period in 2017. The increase was primarily due to our higher average debt balances during the six months ended June 30, 2018 as compared to the same period in 2017.

Interest and Other Income. Interest and other income increased to $0.6 million for the six months ended June 30, 2018 from $0.5 million for the same period in 2017. The increase was primarily due to higher average cash balances during the six months ended June 30, 2018 as compared to the same period in 2017

Foreign Exchange Loss. We recorded a foreign exchange loss of $4.0 million for the six months ended June 30, 2018 as compared to a loss of $1.0 million for the same period in 2017. Foreign exchange gains and losses are primarily unrealized (non-cash) in nature and result from the re-measuring of specific transactions and monetary accounts in a currency other than the functional currency. For example, a U.S. Dollar transaction which occurs in Turkey is re-measured at the period-end to the Turkish Lira amount if it has not been settled previously. The foreign exchange loss for the six months ended June 30, 2018 was due to a decrease in the value of the Turkish Lira as compared to the U.S. Dollar. From June 30, 2017 to June 30, 2018, the Turkish Lira to the U.S. Dollar declined 30.0%. At June 30, 2018, the exchange rate was 4.5607 as compared to 3.5071 at June 30, 2017.

Gain (Loss) on Derivative Contracts. We recorded a net loss on commodity derivative contracts of $3.9 million for the six months ended June 30, 2018 as compared to a net gain of $1.7 million for the same period in 2017. During the six months ended June 30, 2018, we recorded a $0.7 million gain to mark our commodity derivative contracts to their fair value, a $1.3 million loss to mark our currency derivative contracts to their fair value and a $3.2 million loss on settled contracts. During the same period in 2017, we recorded a $1.6 million gain to mark our derivative contracts to their fair value and a $32,000 gain on settled contracts.

Capital Expenditures

For the quarter ended June 30, 2018, we incurred $5.6 million in capital expenditures, including seismic and corporate expenditures, as compared to $4.9 million for the quarter ended June 30, 2017.

In connection with our revised 2018 drilling program, we increased our projected remaining 2018 capital expenditure budget from our prior estimates. We now expect our net field capital expenditures for the remainder of 2018 to range between $24.0 million and $28.0 million. We expect net field capital expenditures during the remainder of 2018 to include between $20.0 million and $26.0 million in drilling and completion expense and approximately $1.2 million in recompletion expense. We expect that cash on hand and cash flow from operations will be sufficient to fund the remainder of our 2018 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected remaining 2018 capital expenditure budget is subject to change.

Cash flows

Net cash provided by operating activities during the six months ended June 30, 2018 was $13.4 million, a decrease from net cash provided by operating activities of $13.6 million for the same period in 2017. The decrease in net cash was primarily due to the timing of collecting our receivables and paying our accounts payable.

Net cash used in investing activities during the six months ended June 30, 2018 was $12.6 million, a decrease from net cash provided by investing activities of $6.1 million for the same period in 2017. The decrease in net cash was primarily due to the proceeds received from the sale of TBNG of $17.8 million during the six months ended June 30, 2017.

Net cash provided by financing activities during the six months ended June 30, 2018 was $1.7 million, an increase from net cash used in financing activities of $15.6 million for the same period in 2017. The increase in net cash was primarily due to a decrease in debt principal repayments as well as additional loan proceeds from the 2018 Term Loan.

Liquidity and Capital Resources

As of June 30, 2018, we had $30.4 million of indebtedness, not including $9.0 million of trade payables, as further described below. We believe that our cash flow from operations will be sufficient to meet our normal operating requirements and to fund planned capital expenditures during the next 12 months. As of June 30, 2018, we had a working capital surplus of $9.2 million.

Outstanding Debt and Series A Preferred Shares

2016 Term Loan. On August 23, 2016, the Turkish branch of TEMI entered into the Credit Agreement with DenizBank. The Credit Agreement is a master agreement pursuant to which DenizBank may make loans to TEMI from time to time pursuant to additional loan agreements.

On August 31, 2016, DenizBank entered the 2016 Term Loan under the Credit Agreement. In addition, we and DenizBank entered into additional agreements with respect to up to $20.0 million of non-cash facilities, including guarantee letters and treasury instruments for future hedging transactions. The 2016 Term Loan bore interest at a fixed rate of 5.25% (plus 0.2625% for Banking and Insurance Transactions Tax per the Turkish government) per annum and was payable in monthly installments of $1.38 million through June 2018. Amounts repaid under the 2016 Term Loan could not be re-borrowed and early repayments under the 2016 Term Loan were subject to early repayment fees. The 2016 Term Loan was guaranteed by DMLP, TransAtlantic Turkey, Talon Exploration, and TransAtlantic Worldwide.

The 2016 Term Loan contained standard prohibitions on the activities of TEMI as the borrower, including prohibitions on granting of liens on its assets, incurring additional debt, dissolving, liquidating, merging, consolidating, paying dividends, making certain investments, selling assets or transferring revenue, and other similar matters. In addition, the 2016 Term Loan prohibited Amity and Petrogas from incurring additional debt. An event of default under the 2016 Term Loan included, among other events, failure to pay principal or interest when due, breach of certain covenants, representations, warranties and obligations, bankruptcy or insolvency and the occurrence of a material adverse effect.

The 2016 Term Loan was secured by a pledge of (i) the stock of TEMI, DMLP, TransAtlantic Turkey and Talon Exploration, (ii) substantially all of the assets of TEMI, (iii) certain real estate owned by Petrogas, (iv) the Gundem real estate and Muratli real estate owned by Gundem and (v) certain Diyarbakir real estate owned 80% by N. Malone Mitchell 3rd and 20% by Selami Erdem Uras. In addition, TEMI assigned its Turkish collection accounts and its receivables from the sale of oil to DenizBank as additional security for the 2016 Term Loan. Gundem is beneficially owned by Mr. Mitchell, his adult children, and Mr. Uras. Mr. Mitchell is our chief executive officer and chairman of our board of directors. Mr. Uras is our vice president, Turkey.

On June 28, 2018 we repaid the 2016 Term Loan in full in accordance with its terms.

2017 Term Loan. On November 17, 2017, DenizBank entered into the 2017 Term Loan under the Credit Agreement. We will use the proceeds from the 2017 Term Loan for general corporate purposes.

The 2017 Term Loan bears interest at a fixed rate of 6.0% (plus 0.3% for Banking and Insurance Transactions Tax per the Turkish government) per annum. The 2017 Term Loan has a grace period which bears no interest or payments due until July 2018 and then is payable in one monthly installment of $1.38 million, nine monthly installments of $1.2 million each through April 2019 and thereafter in eight monthly installments of $1.0 million each through December 2019, with the exception of one monthly installment of $1.2 million occurring in October 2019. The 2017 Term Loan matures in December 2019. Amounts repaid under the 2017 Term Loan may not be re-borrowed, and early repayments under the 2017 Term Loan are subject to early repayment fees. The 2017 Term Loan is guaranteed by Petrogas, Amity, Talon Exploration, DMLP, and TransAtlantic Turkey.

The 2017 Term Loan contains standard prohibitions on the activities of TEMI as the borrower, including prohibitions on granting of liens on its assets, incurring additional debt, dissolving, liquidating, merging, consolidating, paying dividends, making certain investments, selling assets or transferring revenue, and other similar matters. In addition, the 2017 Term Loan prohibits Amity and Petrogas from incurring additional debt. An event of default under the 2017 Term Loan includes, among other events, failure to pay principal or interest when due, breach of certain covenants, representations, warranties and obligations, bankruptcy or insolvency and the occurrence of a material adverse effect.

The 2017 Term Loan is secured by a pledge of (i) the stock of TEMI, DMLP, TransAtlantic Turkey, and Talon Exploration, (ii) substantially all of the assets of TEMI, (iii) certain real estate owned by Petrogas, (iv) the Gundem real estate and Muratli real estate owned by Gundem, (v) certain Diyarbakir real estate owned 80% by N. Malone Mitchell 3rd and 20% Selami Erdem Uras, and (vi) certain Ankara real estate owned 100% by Mr. Uras. In addition, TEMI assigned its Turkish collection accounts and its receivables from the sale of oil to DenizBank as additional security for the 2017 Term Loan. Gundem is beneficially owned by Mr. Mitchell, his adult children, and Mr. Uras. Mr. Mitchell is our chief executive officer and chairman of our board of directors. Mr. Uras is our vice president, Turkey.

At June 30, 2018, we had $20.4 million outstanding under the 2017 Term Loan and no availability, and we were in compliance with the covenants in the 2017 Term Loan.

2018 Term Loan. On May 28, 2018, DenizBank entered into the 2018 Term Loan under the Credit Agreement. We will use the proceeds from the 2018 Term Loan for general corporate purposes.

The 2018 Term Loan bears interest at a fixed rate of 7.25% (plus 0.3% for Banking and Insurance Transactions Tax per the Turkish government) per annum. The 2018 Term Loan has a grace period through July 2018 during which no payments are due. Thereafter, accrued interest on the 2018 Term Loan is payable monthly and the principal on the 2018 Term Loan is payable in five monthly installments of $0.2 million each through December 2018, four monthly installments of $0.5 million each through April 2019, four monthly installments of $1.0 million each through August 2019, and four monthly installments of $0.75 million each through December 2019. The 2018 Term Loan matures in December 2019. Amounts repaid under the 2018 Term Loan may not be reborrowed, and early repayments under the 2018 Term Loan are subject to early repayment fees. The 2018 Term Loan is guaranteed by Petrogas, Amity, Talon Exploration, DMLP, and TransAtlantic Turkey.

The 2018 Term Loan contains standard prohibitions on the activities of TEMI as the borrower, including prohibitions on encumbering or creating restrictions or limitations on all or a part of its assets, revenues, or properties, giving guaranties or sureties, selling assets or transferring revenues, dissolving, liquidating, merging, or consolidating, incurring additional debt, paying dividends, making certain investments, undergoing a change of control, and other similar matters. In addition, the 2018 Term Loan prohibits Amity, Talon Exploration, DMLP, and Transatlantic Turkey from incurring additional debt. An event of default under the 2018 Term Loan includes, among other events, failure to pay principal or interest when due, breach of certain covenants, representations, warranties, and obligations, bankruptcy or insolvency, and the occurrence of a material adverse effect.

The 2018 Term Loan is secured by a pledge of (i) the stock of TEMI, DMLP, TransAtlantic Turkey, and Talon Exploration, (ii) substantially all of the assets of TEMI, (iii) certain real estate owned by Petrogas, (iv) certain Gundem real estate and Muratli real estate owned by Gundem, (v) certain Diyarbakir real estate owned 80% by N. Malone Mitchell 3rd and 20% Selami Erdem Uras, and (vi) certain Ankara real estate owned 100% by Mr. Uras. In addition, TEMI will assigned its Turkish collection accounts and its receivables from the sale of oil to DenizBank as additional security for the 2018 Term Loan. Gundem is beneficially owned by Mr. Mitchell, his adult children, and Mr. Uras. Mr. Mitchell is our chief executive officer and chairman of our board of directors. Mr. Uras is our vice president, Turkey.

At June 30, 2018, we had $10.0 million outstanding under the 2018 Term Loan and no availability, and we were in compliance with the covenants in the 2018 Term Loan.

2017 Notes. The 2017 Notes were issued pursuant to the Indenture. The 2017 Notes bore interest at an annual rate of 13.0%, payable semi-annually, in arrears, on January 1 and July 1 of each year. The 2017 Notes matured on July 1, 2017, and on July 3, 2017, we paid off and retired all remaining outstanding 2017 Notes.

ANBE Note. On December 30, 2015, TransAtlantic USA entered into the ANBE Note. The ANBE Note bore interest at a rate of 13.0% per annum. On December 30, 2015, we borrowed $3.6 million under the ANBE Note for general corporate purposes. On October 31, 2016, TransAtlantic USA entered into the ANBE Amendment, which extended the maturity date of the Note from October 31, 2016 to September 30, 2017, provided for the ANBE Note to be repaid in four quarterly installments of $0.9 million each in December 2016 and March, June and September 2017, and provided for monthly payments of interest. On February 27, 2017, we repaid the ANBE Note in full with proceeds from the sale of TBNG and terminated it.

Series A Preferred Shares. As of June 30, 2018, we had 921,000 Series A Preferred Shares outstanding. The Series A Preferred Shares contain a substantive conversion option, are mandatorily redeemable, and convert into a fixed number of common shares. As a result, under U.S GAAP, we have classified the Series A Preferred Shares within mezzanine equity in our consolidated balance sheets. As of June 30, 2018, we had $21.3 million of Series A Preferred Shares and $24.8 million of Series A Preferred Shares – related party outstanding (See Note 3. "Series A Preferred Shares").

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our derivative contracts may expose us to credit risk in the event of nonperformance by our counterparty. DenizBank is a counterparty to our derivative contracts. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. These agreements allow us to offset our asset position with our liability position in the event of default by the counterparty.

During the second quarter of 2018, there were no material changes in market risk exposures or their management that would affect the Quantitative or Qualitative Disclosures About Market Risk disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017. The following tables sets forth our derivatives contracts, which are settled based on Brent oil pricing, with respect to future crude oil production as of June 30, 2018 and contract rates with respect to foreign exchange:

Fair Value of Commodity Derivative Instruments as of June 30, 2018

	Quantity	Weighted Average Minimum	Weighted Average Maximum Price	Estimated Fair

Type	Period	(Bbl/day)	Price (per Bbl)	(per Bbl)	Additional Call Ceiling	Value of Liability (in thousands)
Collar	July 1, 2018 - December 31, 2018	295	$ 55.00	$ 70.00	$ -	$ (799)
Collar	July 1, 2018 - December 31, 2018	327	$ 56.00	$ 70.00	$ 84.00	(759)
Total Estimated Fair Value of Liability						$ (1,558)

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Fair Value of Currency Derivative Instruments as of June 30, 2018

Type	Buy/Sell	Rate	Settlement Date	Buy Currency	Buy Currency Amount	Sell Currency	Sell Currency Amount	Estimated Fair Value of Liability
								(in thousands)
FXOPT	Buy	4.840	10/16/18	TRY	16,940,000	USD	3,500,000	$ (234)
FXOPT	Buy	4.790	09/03/18	TRY	4,790,000	USD	1,000,000	(169)
FXFWD	Sell	4.930	07/03/18	USD	1,500,000	TRY	7,397,550	(114)
FXFWD	Sell	4.960	07/17/18	USD	3,500,000	TRY	17,351,600	(263)
FXFWD	Sell	4.980	07/31/18	USD	1,500,000	TRY	7,475,250	(112)
FXFWD	Sell	5.010	08/14/18	USD	4,250,000	TRY	21,297,175	(315)
FXFWD	Sell	5.050	09/05/18	USD	1,600,000	TRY	8,085,760	(117)
Total Estimated Fair Value of Liability								$ (1,324)

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is accumulated and communicated to management, including our chief executive officer and principal accounting and financial officer, as appropriate to allow timely decisions regarding required disclosure.

As of June 30, 2018, management carried out an evaluation, under the supervision and with the participation of our chief executive officer and principal accounting and financial officer, of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act). Based upon the evaluation, our chief executive officer and principal accounting and financial officer concluded that, as of June 30, 2018, our disclosure controls and procedures were effective at the reasonable assurance level.

There are inherent limitations to the effectiveness of any system of disclosure controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurances of achieving their control objectives.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2018 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

During the second quarter of 2018, there were no material developments to the Legal Proceedings disclosed in "Part I, Item 3. Legal Proceedings" in our Annual Report on Form 10-K for the year ended December 31, 2017, other than the developments described below:

Bulgarian Ministry of Energy and Economy. In October 2015, the Bulgarian Minister of Energy filed a suit in the Sofia City Court against Direct Bulgaria, claiming $200,000 in liquidated damages for Direct Bulgaria's alleged failure to fulfill its obligations under the Aglen exploration permit work program. In May 2018, the Sofia City Court concluded that Direct Bulgaria did not fail to fulfill its obligations under the Aglen exploration permit work program as Direct Bulgaria received a force majeure event recognition as a result of a fracture stimulation ban in 2012, imposed by the Bulgarian Parliament, which force majeure event had not been terminated before the expiry of Direct Bulgaria's obligations under the Aglen exploration permit work program. Additionally, the Sofia City Court concluded that, even if Direct Bulgaria had failed to fulfill its obligations under the Aglen exploration permit work program, the Bulgarian Minister of Energy failed to file suit within the three-year limitation period. Therefore, the Sofia City Court dismissed all claims of the Bulgarian Minister of Energy and ordered the Bulgarian Minister of Energy to pay Direct Bulgaria's attorney's fees and legal costs for court experts. In June 2018, the Bulgarian Minister of Energy filed an appeal in the Sofia Court of Appeal. We continue to vigorously defend this claim.

Item 1A. Risk Factors

During the second quarter of 2018, there were no material changes to the risk factors disclosed in our Annual Report on Form 10-K for the year ended December 31, 2017.

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

None

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

3.1	Certificate of Continuance of TransAtlantic Petroleum Ltd., dated October 1, 2009 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
3.2	Altered Memorandum of Continuance of TransAtlantic Petroleum Ltd., dated March 4, 2014 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated March 6, 2014, filed with the SEC on March 6, 2014).
3.3	Amended Bye-Laws of TransAtlantic Petroleum Ltd., dated March 4, 2014 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated March 6, 2014, filed with the SEC on March 6, 2014).
3.4	Certificate of Designations of 12.0% Series A Convertible Redeemable Preferred Shares of TransAtlantic Petroleum Ltd. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K dated October 31, 2016, filed with the SEC on November 4, 2016).
4.1	Amended and Restated Registration Rights Agreement, dated December 30, 2008, by and between TransAtlantic Petroleum Corp. and Riata Management, LLC (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated December 30, 2008, filed with the SEC on January 6, 2009).
4.2	Specimen Common Share certificate (incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K dated March 4, 2014, filed with the SEC on March 6, 2014).
10.1	Form of Executive Retention Incentive Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated April 6, 2018, filed with the SEC on April 6, 2018).
10.2	Term Credit Contract, dated May 28, 2018, by and between TransAtlantic Exploration Mediterranean International Pty Ltd and DenizBank A.S. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated May 28, 2018, filed with the SEC on June 1, 2018).
10.3	Sublease Agreement, dated August 7, 2018 and effective June 14, 2018, by and between TransAtlantic Petroleum (USA) Corp. and Longfellow Energy, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 7, 2018, filed with the SEC on August 7, 2018).
31.1*	Certification of the Chief Executive Officer of the Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the Principal Accounting and Financial Officer of the Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer and Principal Accounting and Financial Officer of the Company, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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.

*Filed herewith.
**Furnished herewith.

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.

By: /s/ N. MALONE MITCHELL 3rd
N. Malone Mitchell 3rd

Chief Executive Officer

By: /s/ G. FABIAN ANDA
G. Fabian Anda

Principal Accounting and Financial Officer

Date: August 8, 2018