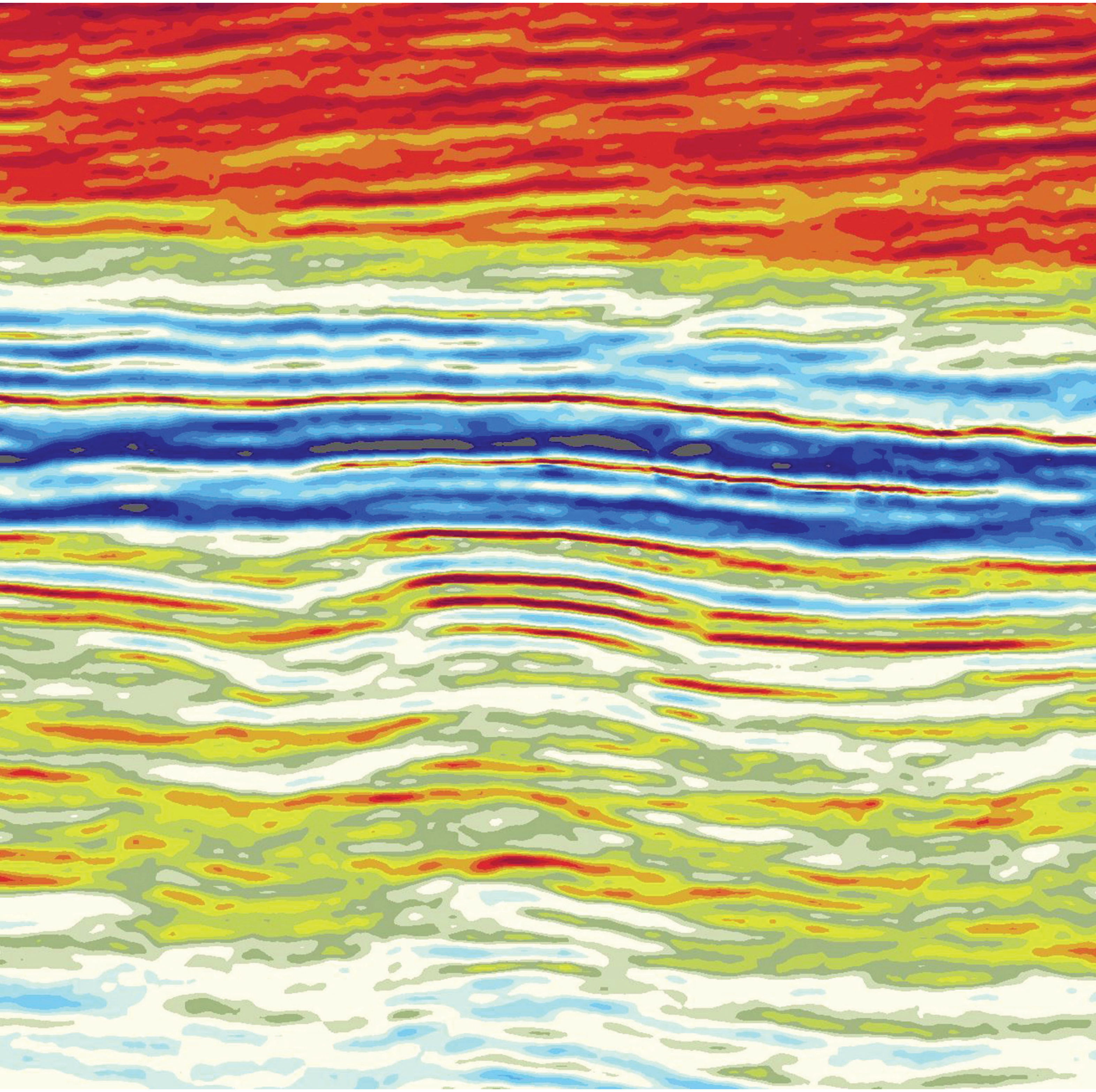
TRANSATLANTIC
Petroleum Ltd.

2018
ANNUAL REPORT



DEAR
FELLOW SHAREHOLDERS:

The upstream oil and gas energy industry continues to experience significant changes in business fundamentals and company valuation. The significant drop in oil prices in late 2018 (now largely recovered) constrained both our cash flow and capital budget during the fourth quarter of 2018 and first quarter of 2019. In addition, industry valuation metrics have returned to discounted cash flow measures from the net asset (NAV) and “potential” valuation metrics common over the past 15 years.

We made one significant oil discovery and several minor oil discoveries in 2018. The results of our Bulgaria exploration well drilled in early 2019 were disappointing. We will continue to endeavor to balance drilling development wells in our current fields with drilling higher risk exploration wells to expand our future development opportunities. Constrained credit availability and existing debt service obligations currently limit our activity level. Under current conditions, we expect to replace our existing base production decline and modestly grow production in 2019.

During 2018, we conducted an extensive and prolonged strategic process seeking liquidity for all shareholders and a premium to prevailing market price. We were unsuccessful in this process, but our Board of Directors continues to investigate and consider opportunities to achieve these objectives.

Turkey experienced significant changes in currency exchange, interest rate, and inflation in 2018. We have and will continue to seek to mitigate risks through forward contracts when available and prudent. Nevertheless, Turkey continues to provide a stable and accommodating environment for our business.

Sincerely,

Malone Mitchell 3rd
Chairman and Chief Executive Officer

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 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** **(Address of principal executive offices)**	**75001** **(Zip Code)**

Registrant's telephone number, including area code: (214) 220-4323

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common shares, par value $0.10	**NYSE American**

Securities registered pursuant to Section 12(g) of the Act:

None

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

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

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☐	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 ☒

The aggregate market value of common shares, par value $0.10 per share, held by non-affiliates of the registrant, based on the last sale price of the common shares on June 30, 2018 (the last business day of the registrant's most recently completed second fiscal quarter), was approximately $41.9 million. For purposes of this computation, all officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such determination should not be deemed an admission that such officers, directors or 10% beneficial owners are, in fact, affiliates of the registrant.

As of March 22, 2019, there were 52,496,666 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2019 Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

TRANSATLANTIC PETROLEUM LTD.
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018
INDEX

Forward-Looking Statements

Certain statements in this Annual Report on Form 10-K constitute "forward-looking statements" within the meaning of applicable U.S. and Canadian securities legislation. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as "plans," "expects," "estimates," "budgets," "intends," "anticipates," "believes," "projects," "indicates," "targets," "objective," "could," "should," "may," or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity, and achievements to differ materially from those expressed or implied by such statements, including the factors discussed under Item 1A. Risk Factors in this Annual Report on Form 10-K. Such factors include, but are not limited to, the following: our ability to access sufficient capital to fund our operations; fluctuations in and volatility of the market prices for oil and natural gas products; the ability to produce and transport oil and natural gas; the results of exploration and development drilling and related activities; global economic conditions, particularly in the countries in which we carry on business, especially economic slowdowns; actions by governmental authorities including increases in taxes, legislative and regulatory initiatives related to fracture stimulation activities, changes in environmental and other regulations, and renegotiations of contracts; political uncertainty, including actions by insurgent groups or other conflicts; the negotiation and closing of material contracts or sale of assets; future capital requirements and the availability of financing; risks associated with drilling, operating and decommissioning wells; actions of third-party co-owners of interests in properties in which we also own an interest; and the other factors discussed in other documents that we file with or furnish to the U.S. Securities and Exchange Commission (the "SEC") and Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and our course of action would depend upon our assessment of the future, considering all information then available. In that regard, any statements as to: future oil or natural gas production levels; capital expenditures; asset sales; the allocation of capital expenditures to exploration and development activities; sources of funding for our capital expenditure programs or operations; drilling of new wells; demand for oil and natural gas products; expenditures and allowances relating to environmental matters; dates by which certain areas will be developed or will come on-stream; expected finding and development costs; future production rates; ultimate recoverability of reserves, including the ability to convert probable and possible reserves to proved reserves; dates by which transactions are expected to close; future cash flows, uses of cash flows, collectability of receivables and availability of trade credit; expected operating costs; changes in any of the foregoing; and other statements using forward-looking terminology are forward-looking statements, and there can be no assurance that the expectations conveyed by such forward-looking statements will, in fact, be realized.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

Readers should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law.

Glossary of Selected Oil and Natural Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

2D seismic. Geophysical data that depict the subsurface strata in two dimensions.

3D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic.

Appraisal wells. Wells drilled to convert an area or sub-region from the resource to the reserves category.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bbl/d. Barrels of oil per day.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent. Boe is not included in the DeGolyer and MacNaughton reserves report and is derived by us by converting natural gas to oil in the ratio of six Mcf of natural gas to one Bbl of oil. The conversion factor is the current convention used by many oil and natural gas companies. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Boepd. Barrels of oil equivalent per day.

Commercial well; commercially productive well. An oil and natural gas well which produces oil and natural gas in sufficient quantities such that proceeds from the sale of such production exceed royalties, production expenses, and taxes.

Completion. The communication of the formation to the well bore, which may include installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres which are allocated to a production license or assignable to producing wells or wells capable of production.

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

Directional drilling. The technique of drilling a well while varying the angle of direction of a well and changing the direction of a well to hit a specific target.

Dry hole; dry well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Exploitation. The continuing development of a known producing formation in a previously discovered field, including efforts to maximize the ultimate recovery of oil or natural gas from the field by development wells, secondary recovery equipment, or other suitable processes and technology.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field or not in an area previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well.

Farm-in or farm-out. An agreement to assign an interest in a drilling location and related acreage conditional upon the drilling of a well on that location, the completion of other work commitments related to that acreage, or some combination thereof.

Formation. A geological stratum identifiable by distinct age or composition that was deposited under the same general geologic conditions.

Frac; fracture stimulation. A stimulation treatment involving the fracturing of a reservoir and then injecting water and generally sand and/or chemicals into the fractures under pressure to contact greater surface area to stimulate hydrocarbon production in low-permeability reservoirs.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A technique used in certain formations where a well is drilled near vertically to a certain depth and then drilled at an angle parallel with a specified formation.

Initial production rate. Generally, the maximum 24-hour production volume from a well.

Mbbl. One thousand stock tank barrels.

Mboe. One thousand barrels of oil equivalent.

Mboepd. One thousand barrels of oil equivalent per day.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One thousand cubic feet of natural gas per day.

Mmbbl. One million stock tank barrels.

Mmboe. One million barrels of oil equivalent.

Mmcf. One million cubic feet of natural gas.

Mmcf/d. One million cubic feet of natural gas per day.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Overriding royalty interest. An interest in an oil or natural gas property entitling the owner to a share of oil and natural gas production free of some costs of production as defined by agreement.

Play. A term applied during a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

Present value of estimated future net revenues or PV-10. The present value of estimated future net revenues is an estimate of future net revenues from a property at the date indicated, without giving effect to derivative financial instrument activities, after deducting production and ad valorem taxes, future capital costs, abandonment costs, and operating expenses, but before deducting future federal income taxes. The future net revenues have been discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil and natural gas prices and operating and capital costs at the date indicated, at its acquisition date, or as otherwise indicated. We believe that the present value of estimated future net revenues before income taxes, while not a financial measure in accordance with U.S. generally accepted accounting principles ("U.S. GAAP"), is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially.

Productive well. A productive well is a well that is not a dry well.

Proved developed reserves. Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate.

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (“EUR”) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Recompletion. An operation within an existing well bore to make the well produce oil or natural gas from a different, separately producible zone other than the zone from which the well had been producing or to stimulate a currently producing formation with a different completion.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Sales volumes. The amount of production of oil or natural gas sold after deducting royalties and working interests owned by third parties.

Shale. Fine-grained sedimentary rock composed of consolidated clay or mud but also commonly containing carbonate or elastic material. Shale is one of the most frequently occurring sedimentary rocks.

Standardized measure of discounted future net cash flows or the Standardized Measure. Under the Standardized Measure, future cash flows for the years ended December 31, 2018 and 2017 are estimated by applying the simple average spot prices for the trailing twelve month period using the first day of each month beginning on January 1 and ending on December 1 of each respective year, adjusted for fixed and determinable escalations, to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end and future plugging and abandonment costs to determine pre-tax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Tcf. One trillion cubic feet of natural gas.

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

Wellhead production. The volume of oil or natural gas produced before deducting royalties and working interests owned by third parties prior to any oil and natural gas lost or used from wellhead to market.

Working interest (“WI”). The operating interest that gives the owner the right to drill, produce and conduct activities on the property and a share of production.

PART I

Item 1. Business

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

Our Business

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 December 31, 2018, we held interests in 372,050 and 162,500 net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria, respectively. As of March 22, 2019, approximately 48% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, the chairman of our board of directors and our chief executive officer.

Based on the reserves report prepared by DeGolyer and MacNaughton, independent petroleum engineers, our estimated proved reserves at December 31, 2018 in Turkey were 10,383 Mboe, of which 96.1% was oil. Of these estimated proved reserves, 52.2% were proved developed reserves. As of December 31, 2018, the Standardized Measure and PV-10 of our proved reserves in Turkey were $266.2 million and $320.6 million, respectively. See “Item 2. Properties—Value of Proved Reserves” for a reconciliation of PV-10 to the Standardized Measure.

Recent Developments

2019 Term Loan. On February 22, 2019, the Turkish branch of TransAtlantic Exploration Mediterranean International Pty Ltd (“TEMI”) entered into a $20.0 million term loan (the “2019 Term Loan”) with DenizBank, A.S (“DenizBank”) under our general credit agreement with DenizBank (the “Credit Agreement”).

The 2019 Term Loan bears interest at a fixed rate of 7.5% (plus 0.3% for Banking and Insurance Transactions Tax per the Turkish government) per annum. The 2019 Term Loan has a ten-month grace period during which the 2019 Term Loan bears interest but no payments are due other than a single interest only payment of $0.76 million in August 2019. After the ten-month grace period, the 2019 Term Loan is payable in fourteen monthly principal installments of $1.43 million plus interest. The 2019 Term Loan matures in February 2021. Amounts repaid under the 2019 Term Loan may not be re-borrowed, and early repayments under the 2019 Term Loan are subject to early repayment fees.

Our Properties and Operations

Summary of Geographic Areas of Operations

The following table shows net reserves information as of December 31, 2018:

	Proved Developed Reserves (Mboe)	Proved Undeveloped Reserves (Mboe)	Total Proved Reserves (Mboe)	Probable Reserves (Mboe)	Possible Reserves (Mboe)
Turkey	5,423	4,960	10,383	5,884	6,360

Turkey

As of December 31, 2018, we held interests in five onshore exploration licenses and 18 onshore production leases covering a total of 443,268 gross (372,050 net) acres in Turkey. As of December 31, 2018, we had total net proved reserves of 9,976 Mbbl of oil and 2,440 Mmcf of natural gas, net probable reserves of 5,748 Mbbl of oil and 817 Mmcf of natural gas and net possible reserves of 6,204 Mbbl of oil and 938 Mmcf of natural gas in Turkey. During 2018, our average wellhead production was 3,355 net Boepd of oil and natural gas in Turkey. The following summarizes our core producing properties in Turkey:

Southeastern Turkey. During 2018, substantially all of our oil production was concentrated in Southeastern Turkey, primarily in the Arpatepe, Bahar, Goksu, Selmo, and Yeniev oil fields. These fields are located in the northwest region within the Turkish portion of the North Arabian Basin. The North Arabian Basin includes prolific oil trends that extend from Iran and Iraq into Turkey.

We hold a 100% working interest in the Selmo production lease, which expires in June 2025. We also hold a 100% working interest in the Selmo exploration license. The Selmo oil field is the second largest oil field in Turkey in terms of historical cumulative production and is responsible for a large portion of our current crude oil production. For 2018, our net wellhead production of crude oil from the Selmo field was 653,719 Bbls at an average rate of 1,791 Bbl/d. Turkiye Petrolleri Anonim Ortakligi ("TPAO"), a Turkish government-owned oil and natural gas company, and Türkiye Petrol Rafinerileri A.Ş. ("TUPRAS"), a privately-owned oil refinery in Turkey, purchase all of our crude oil production, which are transported by truck to their neighboring facilities. At December 31, 2018, we had 55 gross and net producing wells in the Selmo oil field.

We hold a 100% working interest in the Molla exploration license, which includes the Bahar and Cavuslu fields. We also hold a 100% working interest in each of the three Molla production leases, which includes the Goksu, Yeniev, West Yeniev, Pinar, Catak and Bati Yasince fields. In the Molla licenses, we target Bedinan, Dadas, Hazro, and Mardin formations, which produce on the licenses. For 2018, our wellhead production of crude oil from the Molla area was 468,514 Bbls at an average rate of 1,284 Bbl/d. At December 31, 2018, we had 16 gross and net producing wells on the Molla licenses.

We hold a 50% working interest in our Arpatepe production lease. For 2018, our share of wellhead production of net crude oil from the Arpatepe field was 51,127 Bbls at an average rate of 140 Bbl/d. At December 31, 2018, we had five producing wells on the Arpatepe production lease. We have operated the Arpatepe production lease since December 2015.

We hold a 50% working interest in the Bakuk production lease. In 2017, our production was shut in due to security precautions and remained shut in during 2018.

Northwestern Turkey. Substantially all of our natural gas production is concentrated in the Thrace Basin, which is one of Turkey's most productive onshore natural gas regions. It is located in northwestern Turkey close to Istanbul province. For 2018, our net wellhead production was 238,865 Mcf at an average rate of 645 Mcf/d from all of the gas fields.

Bulgaria

As of December 31, 2018, we held interests in one production concession covering a total of 162,500 net undeveloped acres in Bulgaria. During 2018, we had no production or reserves in Bulgaria.

Current Operations

Southeastern Turkey

Molla

Yeniev Field. Both the Yeniev-1 and West Yeniev-1 wells continue flowing naturally with little water. In November 2018, we spud the East Yeniev-1 appraisal well to further delineate the structure. The well was drilled to a total measured depth of 9,900 feet and encountered hydrocarbon shows in the Mardin and Bedinan formations. Completion operations began in January 2019 and resulted in a discovery in the Mardin formation.

Other. We spud the Blackeye-1 well in January 2019. The well was drilled to a total measured depth of 11,105 feet and encountered oil shows in the Hazro, Mardin, and Bedinan formations. Completion operations began in February 2019.

Selmo

We have completed the initial phase of operations in the Selmo-1 well to re-enter and test the Permian formation, establishing the productivity of the Permian formation. During a short-term flow test of a previously untested interval, the Selmo-1 well tested 45.6 API condensate along with natural gas containing a high carbon dioxide percentage component. While the Selmo-1 well lies in what is interpreted as the gas cap of the structure, the positive test results warrant further testing lower on the structure.

Northwestern Turkey

Thrace Basin BCGA

We continue to evaluate our prospects in the Thrace Basin's Basin Center Gas Accumulation ("Thrace Basin BCGA") in light of the recent 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.

Subsequent to drilling and testing of the Yamalik-1 well, the joint venture between Valeura and Equinor announced a three-well program. In the first quarter of 2019, Valeura and Equinor announced that they drilled and cased a second well in the Thrace Basin BCGA, the Inanli-1 well. According to Valeura and Equinor, the well was drilled to a total depth of 4,885 meters and encountered 1,615 meters of high net-to-gross sandstone, which they interpreted to contain over-pressured gas. Valeura and Equinor announced that they expect to complete the well in the first quarter of 2019. In the first quarter of 2019, Valeura and Equinor announced that they spud the Devepinar-1 appraisal well and drilled it to intermediate casing point at 3,375 meters. According to Valeura and Equinor, the Devepinar-1 appraisal well is designed as a 20-kilometer step-out well to test the lateral extent of the Thrace Basin BCGA.

We expect to spud a shallow exploration well on our license in the Thrace Basin in the second quarter of 2019.

Bulgaria

We commenced the side-track and re-drilling of the Deventci R-1 well in December 2018, targeting the Ozirovu and Dolmi Dabnik formations. The well was drilled to a total depth of 16,450 feet. Although we encountered the targeted formations, tests did not indicate commercial quantities of reservoir quality rock. We are currently evaluating future activity in Bulgaria.

Planned Operations

We expect our net field capital expenditures for 2019 to range between $25.0 million and $30.0 million. We expect net field capital expenditures during 2019 to include between $24.0 million and $29.0 million in drilling and completion expense for 10 planned wells and approximately $1.0 million for recompletions. We expect that cash on hand and cash flow from operations will be sufficient to fund our 2019 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2019 capital expenditure budget is subject to change.

Customers

Oil. During 2018, 87.5% of our oil production, which is U.S. Dollar indexed, was concentrated in the Selmo and Bahar oil fields in Turkey. TUPRAS purchases substantially all of our oil production. During 2018, we sold $68.2 million of oil to TUPRAS, representing 96.4% of our total revenues. We sell all of our Southeastern Turkey oil to TUPRAS pursuant to a domestic crude oil purchase and sale agreement. Under the purchase and sale agreement, TUPRAS purchases oil produced by us and delivered to our TPAO Batman tanks and to the Boru Hatlari ile Petrol Tasima A.S. (“BOTAŞ”) Dörtyol plant. The price of the oil delivered pursuant to the purchase and sale agreement is determined under the Petroleum Market Law No. 5015 under the laws of the Republic of Turkey. The purchase and sale agreement automatically renews for successive one-year terms unless earlier terminated in writing by either party. All payments for our oil production made by TUPRAS for the past nine years have been in full and on time. No other purchasers of our oil accounted for more than 10% of our total revenues.

Natural Gas. During 2018, no purchasers of our natural gas production, which is indexed on the New Turkish Lira (“TRY”), accounted for 10% or more of our total revenues.

Competition

We operate in the highly competitive areas of oil and natural gas exploration, development, production and acquisition with a number of other companies, including U.S.-based and international companies doing business in each of the countries in which we operate. We face competition from both major and other independent oil and natural gas companies in each of the following areas seeking oil and natural gas exploration licenses and production licenses and leases and acquiring desirable producing properties or new leases for future exploration.

Many of our competitors have substantially greater financial, managerial, technological and other resources than we do. To the extent competitors are able to pay more for properties than we are paying, we will be at a competitive disadvantage. Further, many of our competitors enjoy technological advantages over us and may be able to implement new technologies more rapidly than we can. Our ability to explore for and produce oil and natural gas prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Fracture Stimulation Program

Oil and natural gas may be recovered from our properties through the use of fracture stimulation combined with modern drilling and completion techniques. Fracture stimulation involves the injection of water, and generally sand and/or chemicals under pressure into formations to fracture the oil or gas formation by contacting greater surface area to stimulate production. We have successfully utilized fracture stimulation in our Thrace Basin, Molla, and Selmo licenses and production leases.

Fracture stimulations in Thrace Basin and Molla are conducted in a low permeability reservoir. These stimulations generally consist of injecting between 20,000 and 100,000 gallons of fluid that contain between 80,000 and 150,000 pounds of sand per stage. Fluids are generally a mixture of slickwater and gels, which is typical in stimulation. The size of fracture stimulation treatments is dependent on net pay thickness and stress barriers.

Although the cost of each well will vary, on average approximately 10% to 60% of the total cost of completing a well in both Thrace Basin and Molla is associated with stimulation activities. We account for these costs as typical drilling and completion costs and include them in our capital expenditure budget.

We diligently review best practices and industry standards in connection with fracture stimulation activities and strive to comply with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across potable water sources, cementing surface casing from setting depth to surface and second string from setting depth up-well past multiple frac barriers above the formation and, in some cases, to surface, continuously monitoring the fracture stimulation process in real time, and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources or at a certified water treatment plant. In Southeast Turkey, the base of potable water is generally 3,000 feet to 8,000 feet above the hydrocarbon zones. There have not been any incidents, citations, or suits involving environmental concerns related to our fracture stimulation operations on our properties.

In the Thrace Basin, Selmo, and Molla, we have access to water resources which we believe will be adequate to execute any stimulation activities that we may perform in the future. We also employ procedures for environmentally friendly disposal of fluids recovered from fracture stimulation.

For more information on the risks of fracture stimulation, please read “Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry—Our oil and natural gas operations are subject to extensive and complex laws and government regulation in the jurisdictions in which we operate and compliance with existing and future laws may increase our costs or impair our operations” and “Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry—Legislative and regulatory initiatives and increased public scrutiny relating to fracture stimulation activities could result in increased costs and additional operating restrictions or delays.”

Governmental Regulations

Government Regulations. Our current or future operations, including exploration and development activities on our properties, require permits from various governmental authorities, and such operations are and will be governed by laws and regulations concerning exploration, development, production, exports, taxes, labor laws and standards, occupational health, waste disposal, toxic substances, land use, environmental protection and other matters. Compliance with these requirements may prove to be difficult and expensive. Due to our international operations, we are subject to the following issues and uncertainties that can affect our operations adversely:

- the risk of expropriation, nationalization, war, revolution, political instability, border disputes, renegotiation or modification of existing contracts, and import, export and transportation regulations and tariffs;
- laws of foreign governments affecting our ability to fracture stimulate oil or natural gas wells, such as the legislation enacted in Bulgaria in January 2012;
- the risk of not being able to procure residency and work permits for our expatriate personnel;
- taxation policies, including royalty and tax increases and retroactive tax claims;
- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over international operations;
- laws and policies of the United States affecting foreign trade, taxation and investment, including anti-bribery and anti-corruption laws;

- the possibility of being subjected to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- the possibility of restrictions on repatriation of earnings or capital from foreign countries.

Permits and Licenses. In order to carry out exploration and development of oil and natural gas interests or to place these into commercial production, we may require certain licenses and permits from various governmental authorities. There can be no guarantee that we will be able to obtain all necessary licenses and permits that may be required. In addition, such licenses and permits are subject to change and there can be no assurances that any application to renew any existing licenses or permits will be approved.

Repatriation of Earnings. Currently, there are no prohibitions on the repatriation of earnings or capital to foreign entities from Turkey or Bulgaria. However, there can be no assurance that any such prohibitions on repatriation of earnings or capital from the aforementioned countries or any other country where we may invest will not be imposed in the future. We may be liable for the payment of taxes upon repatriation of certain earnings from the aforementioned countries.

Environmental. The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which we operate. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products and waste created by water and air pollution control procedures. These regulations can have an impact on the selection of drilling locations and facilities, and potentially result in increased capital expenditures. In addition, environmental legislation may require those wells and production facilities to be abandoned and sites reclaimed to the satisfaction of local authorities. Such regulation has increased the cost of planning, designing, drilling, operating and, in some instances, abandoning wells. We are committed to complying with environmental and operational legislation wherever we operate.

Such laws and regulations not only expose us to liability for our own negligence but may also expose us to liability for the conduct of others or for our actions that were in compliance with all applicable laws at the time those actions were taken. We may incur significant costs as a result of environmental accidents, such as oil spills, natural gas leaks, ruptures, or discharges of hazardous materials into the environment, including clean-up costs and fines or penalties. Additionally, we may incur significant costs in order to comply with environmental laws and regulations and may be forced to pay fines or penalties if we do not comply.

There has been an increase in interest among the media, government regulators and private citizens concerning the possible negative environmental and geological effects of fracture stimulation. Some have alleged that fracture stimulation results in the contamination of aquifers and may even contribute to seismic activity. In January 2012, the government of Bulgaria enacted legislation that banned the fracture stimulation of oil and natural gas wells in the Republic of Bulgaria and imposed large monetary penalties on companies that violate that ban. There is a risk that Turkey could at some point impose similar legislation or regulations. Such legislation or regulations could severely impact our ability and the cost to drill and complete wells. We are committed to complying with legislation and regulations involving fracture stimulation wherever we operate.

Insurance

We currently carry general liability insurance and excess liability insurance, including pollution insurance, with a combined annual limit of $13.0 million per occurrence and $16.0 million in the aggregate. These insurance policies contain maximum policy limits and are subject to customary exclusions and limitations. Our general liability insurance covers us and our subsidiaries for third-party claims and liabilities arising out of lease operations and related activities. The excess liability insurance is in addition to, and is triggered if, the general liability insurance per occurrence limit is reached. We also maintain control of well insurance. Our control of well insurance has a per occurrence and combined single limit of $25.0 million and is subject to deductibles ranging from $10,000 to $250,000 per occurrence. In addition, we carry a political risk policy, which covers our scheduled production facilities in the event of an act of terrorism with an annual limit of $8.6 million. We will continue to monitor our insurance coverage and will maintain appropriate levels of insurance to satisfy applicable regulations, as well as maintain levels of insurance appropriate for prudent operations within the industry in which we operate.

We require our third-party service providers to sign master service agreements with us pursuant to which they agree to indemnify us for the personal injury and death of the service provider's employees as well as subcontractors that are hired by the service provider. Similarly, we generally agree to indemnify our third-party service providers against similar claims regarding our employees and our other contractors.

We also require our third-party service providers that perform fracture stimulation operations for us to sign master service agreements containing the indemnification provisions noted above. We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to fracture stimulation operations. We believe that our general liability, excess liability and pollution insurance policies would cover third-party claims related to fracture stimulation operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated environmental clean-up responsibilities.

Bermuda Tax Exemption

As a Bermuda exempted company and under current Bermuda law, we are not subject to tax on profits, income or dividends, nor is there any capital gains tax applicable to us in Bermuda. Profits can be accumulated, and it is not obligatory for us to pay dividends.

Furthermore, we have received an assurance from the Minister of Finance of Bermuda under the Exempted Undertakings Tax Protection Act 1966, as amended, that in the event that Bermuda enacts any legislation imposing tax computed on profits, income, any capital asset, gain or appreciation, we and any of our operations or our shares, debentures or other obligations shall be exempt from the imposition of such tax until March 31, 2035, provided that such exemption shall not prevent the application of any tax payable in accordance with the provisions of the Land Tax Act, 1967 or otherwise payable in relation to land in Bermuda leased to us.

We are required to pay an annual government fee (the "AGF"), which is determined on a sliding scale by reference to our authorized share capital and share premium account, with a minimum fee of $1,995 Bermuda Dollars and a maximum fee of $31,120 Bermuda Dollars. The Bermuda Dollar is treated at par with the U.S. Dollar. The AGF is payable each year on or before the end of January and is based on the authorized share capital and share premium account on August 31 of the preceding year.

In Bermuda, stamp duty is not chargeable in respect of the incorporation, registration, licensing of an exempted company or, subject to certain minor exceptions, on their transactions.

Employees

As of December 31, 2018, we employed 112 people in Turkey, 30 people in Addison, Texas and 6 people in Bulgaria. Approximately 36 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with the Petroleum, Chemical and Rubber Workers Union of Turkey ("PETROL-IS"). We consider our employee relations to be satisfactory.

Formation

We were incorporated under the laws of British Columbia, Canada on October 1, 1985 under the name Profco Resources Ltd. and continued to the jurisdiction of Alberta, Canada under the *Business Corporations Act* (Alberta) on June 10, 1997. Effective December 2, 1998, we changed our name to TransAtlantic Petroleum Corp. Effective October 1, 2009, we continued to the jurisdiction of Bermuda under the Bermuda *Companies Act 1981* under the name TransAtlantic Petroleum Ltd.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), are made available free of charge on our website at www.transatlanticpetroleum.com as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. The SEC maintains a website that contains reports, proxy and information statements, and other information regarding issues, including us, that electronically file with the SEC at http://www.sec.gov.

Our common shares are listed on the NYSE American exchange. Section 110 of the NYSE American company guide permits the NYSE American to consider the laws, customs and practices of foreign issuers in relaxing certain NYSE American listing criteria, and to grant exemptions from NYSE American listing criteria based on these considerations. A description of the significant ways in which our governance practices differ from those followed by US domestic companies pursuant to NYSE American standards is available on our website, www.transatlanticpetroleum.com, under Corporate Governance page, which is accessible under the About heading on the home page.

Executive Officers of the Registrant

The following table and text sets forth certain information with respect to our executive officers as of March 1, 2019:

Name	Age	Positions
N. Malone Mitchell 3rd	57	Chairman and Chief Executive Officer
Todd C. Dutton	65	President
Michael P. Hill	37	Chief Accounting Officer
Tabitha T. Bailey	33	Vice President, General Counsel and Corporate Secretary
Harold "Lee" Muncy	66	Vice President of Geosciences

N. Malone Mitchell 3rd has served as our chief executive officer since May 2011, as a director since April 2008 and as our chairman since May 2008. Since 2005, Mr. Mitchell has served as the president of Riata Corporate Group, LLC and Longfellow Energy, LLC, a Dallas-based private oil and natural gas exploration and production company. From June to December 2006, Mr. Mitchell served as president and chief operating officer of SandRidge Energy, Inc. (formerly Riata Energy, Inc.), an independent oil and natural gas company concentrating in exploration, development and production activities. Until he sold his controlling interest in Riata Energy, Inc. in June 2006, Mr. Mitchell also served as president, chief executive officer and chairman of Riata Energy, Inc., which Mr. Mitchell founded in 1985 and built into one of the largest privately held energy companies in the United States. Mr. Mitchell earned a B.S. from Oklahoma State University.

Todd C. Dutton has served as our president since May 2014. Mr. Dutton has served as president of Longfellow Energy, LP ("Longfellow"), a Dallas, Texas-based independent oil and natural gas exploration and production company owned by our chairman and chief executive officer, Mr. Mitchell 3rd and his family, since January 2007, where his primary responsibility is to originate and develop oil and natural gas projects. He brings 40 years of experience in the oil and natural gas industry, focusing on exploration, acquisitions and property evaluation. He has served in various supervisory and management roles at Texas Pacific Oil Company, Coquina Oil Corporation, BEREXCO INC. and Riata Energy, Inc. Mr. Dutton earned a B.B.A. in Petroleum Land Management from the University of Oklahoma.

Michael P. Hill has served as our chief accounting officer and principal accounting and principal financial officer since January 2019. Mr. Hill served as chief accounting officer of AVAD Energy Partners, LLC from December 2017 to January 2019, where he was responsible for internal and external financial reporting, cash management, debt compliance, relationships with oil and gas purchasers, execution of the hedging strategy, and analyzing profitability. Previously, Mr. Hill served as our corporate controller from June 2017 to December 2017, our financial reporting manager at from 2012 to June 2017, and our senior financial reporting accountant from 2010 to 2012. Mr. Hill also served as international controller at Toreador Resources Corporation and began his career as an auditor at Grant Thornton LLP. Mr. Hill earned a B.B.A. in Accounting and Finance from Texas Tech University.

Tabitha T. Bailey has served as our vice president, general counsel, and corporate secretary since January 2019, and as associate general counsel from June 2017 to January 2019. Previously, Ms. Bailey served as an attorney in the corporate department at Akin Gump Strauss Hauer & Feld LLP from October 2013 to June 2017, where she represented clients in mergers, acquisitions, capital raising, securities compliance, and other strategic transactions across a broad range of industries. Ms. Bailey began her career as an attorney in the corporate department at Haynes and Boone, LLP. Ms. Bailey earned a B.A. in International Studies and Economics from the University of Mississippi and a J.D. from Vanderbilt University Law School.

Harold "Lee" Muncy has served as our vice president of geosciences since June 2014. Mr. Muncy previously served as vice president, exploration for the Bass Companies, a group of Fort Worth, Texas-based independent oil and natural gas exploration and production companies, where he worked from 2000 to 2012. He brings more than 36 years of geological experience in the oil and natural gas industry, where he has focused on exploration, exploitation and worldwide transactions. He began his career as a geologist with Mobil Oil Corporation and served as exploration manager for Fina Oil & Chemical Company and vice president of exploration and land for TransTexas Gas Corp. Mr. Muncy earned a B.S. and an M.S. in Geology & Mineralogy from The Ohio State University.

Item 1A. Risk Factors

Risks Related to Our Business

All of our operations are conducted in Turkey and Bulgaria, and we are subject to political, economic and other risks and uncertainties in these countries.

All of our operations are performed in the emerging markets of Turkey and Bulgaria, which may expose us to risks different than those associated with U.S. or Canadian markets. Due to our foreign operations, we are subject to the following issues and uncertainties that can adversely affect our operations:

- the risk of, and disruptions due to, expropriation, nationalization, war, terrorism, revolution, election outcomes, economic instability, political instability, or border disputes;
- the uncertainty of local contractual terms, renegotiation or modification of existing contracts and enforcement of contractual terms in disputes before local courts;
- the risk of import, export and transportation regulations and tariffs, including boycotts and embargoes;
- the risk of not being able to procure residency and work permits for our expatriate personnel;
- the requirements or regulations imposed by local governments upon local suppliers or subcontractors, or being imposed in an unexpected and rapid manner;
- taxation and revenue policies, including royalty and tax increases, retroactive tax claims and the imposition of unexpected taxes or other payments on revenues;
- exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over foreign operations;
- laws and policies of Canada and the United States, including the U.S. Foreign Corrupt Practices Act (“FCPA”), and of the other countries in which we operate affecting foreign trade, taxation and investment, including anti-bribery and anti-corruption laws;
- our internal control policies may not protect us from reckless and criminal acts committed by our employees or agents, including violations or alleged violations of the FCPA;
- the possibility of being subjected to the exclusive jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of courts in the United States; and
- the possibility of restrictions on repatriation of earnings or capital from foreign countries.

To manage these risks, we sometimes form joint ventures and/or strategic partnerships with local private and/or governmental entities. Local partners provide us with local market knowledge. However, there can be no assurance that changes in conditions or regulations in the future will not affect our profitability or ability to operate in such markets.

Acts of violence, terrorist attacks or civil unrest in Turkey and nearby countries could adversely affect our business.

During 2018, we derived all of our revenue from our operations in Turkey and substantially all of our oil production was derived from Southeastern Turkey. Historically, the southeastern area of Turkey and nearby countries such as Iran, Iraq and Syria have occasionally experienced political, social, security and economic problems, terrorist attacks, insurgencies, war and civil unrest. Since December 2010, political instability has increased in a number of countries in the Middle East and North Africa. As a result of the civil war in Syria, hundreds of thousands of Syrian refugees have fled to Turkey. In addition, tensions continue between Turkey and Syria. In addition, Turkey has experienced numerous terrorist incidents, and in July 2016, there was a failed attempt to overthrow the government of President Recep Tayyip Erdoğan.

The recent conflict with the terrorist group Islamic State in Iraq and Syria (“ISIS”), the tension in and involving the Kurdish regions of northern Iraq, which are contiguous to the region where our Southeast Turkey licenses are located, and the aftermath the attempted coup d’etat may have political, social or security implications in Turkey or otherwise may impact the Turkish economy.

Turkey has also experienced problems with domestic terrorist and ethnic separatist groups. For example, Turkey has been in conflict for many years with the People’s Congress of Kurdistan (formerly known as the PKK), an organization that is listed as a terrorist organization by states and organizations, including Turkey, the European Union and the United States.

The potential impact on our business from such events, conditions and conflicts in these countries is uncertain. We may be unable to access the locations where we conduct operations or transport oil to our offtakers in a reliable manner. In those locations where we have employees or operations, we may incur substantial costs to maintain the safety of our personnel and our operations.

We have a history of losses and may not achieve consistent profitability in the future.

We have incurred substantial losses in prior years. During 2018, we generated a net loss of $5.2 million. We will need to generate and sustain increased revenue levels in future periods in order to become consistently profitable, and even if we do, we may not be able to maintain or increase our level of profitability. We may incur losses in the future for a number of reasons, including the risks described herein, unforeseen expenses, difficulties, complications and delays and other unknown risks.

We depend on the services of our chairman and chief executive officer.

We depend on the performance of Mr. Mitchell, our chairman and chief executive officer. The loss of Mr. Mitchell could negatively impact our ability to execute our strategy. We do not maintain a key person life insurance policy on Mr. Mitchell.

We could lose permits or licenses on certain of our properties in Turkey unless the permits or licenses are extended or we commence production and convert the permits or licenses to production leases or concessions.

At December 31, 2018, of our total net undeveloped acreage, 16.2% and 32.2% will expire during 2019 and 2020, respectively, unless we are able to extend the permits or licenses covering this acreage or commence production on this acreage and convert the permits or licenses into production leases or concessions. If our permits or licenses expire, we will lose our right to explore and develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including factors that are beyond our control. Such factors include drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. In addition, if our liquidity continues to be constrained and we are not able to access additional capital, we may be unable to fund the drilling of some of our obligation wells, and we could lose some of our licenses.

Substantially all of our oil is sold to one customer, and the loss of this customer could have a material adverse impact on our results of operations.

TUPRAS, an affiliate of Koç Holding, purchases substantially all of our oil production from Turkey, representing 96.4% of our total revenues in 2018. If TUPRAS reduces its oil purchases or fails to purchase our oil production, or there is a material non-payment, our results of operations could be materially and adversely affected. TUPRAS may be subject to its own operating risks that could increase the risk that it could default on its obligations to us. Under Turkish law, TUPRAS is obligated to purchase all of our oil production in Turkey, and we are prohibited from selling any of our oil produced in Turkey to any other customer. Pursuant to a purchase and sale agreement with TUPRAS, the price of oil delivered to TUPRAS is determined under the Petroleum Market Law No. 5015 under the laws of the Republic of Turkey. Changes to Turkish law could adversely affect our business and results of operations.

A significant failure of our computer systems may increase our operating costs or otherwise adversely affect our business.

We depend upon our computer systems to perform accounting and administrative functions as well as manage other aspects of our operations. We maintain normal backup polices with respect to our computer systems and networks. Nevertheless, our computer systems and networks are subject to risks that may cause interruptions in service, including, but not limited to, security breaches, physical damage, power loss, software defects, hacking attempts, computer viruses and malware, lost data and programming and/or human errors. Significant interruptions in service, security breaches or lost data may have a material adverse effect on our business, financial condition or results of operations.

Our indebtedness could adversely affect our financial condition and prevent us from fulfilling our debt service and other obligations.

Our indebtedness could have significant effects on our business. For example, it could:

- make it more difficult for us to satisfy our financial obligations, including with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing our indebtedness;
- increase our vulnerability to general adverse economic, industry and competitive conditions, especially declines in oil and natural gas prices;
- limit our ability to borrow additional funds, and
- limit our financial flexibility

Each of these factors may have a material and adverse effect on our financial condition and viability. Our ability to make payments with respect to our indebtedness and to satisfy any other debt obligations will depend on commodity prices and our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting us and our industry, many of which are beyond our control.

We could experience labor disputes that could disrupt our business in the future.

As of December 31, 2018, 36 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with PETROL-IS. Potential work disruptions from labor disputes with these employees could disrupt our business and adversely affect our financial condition and results of operations.

Risks Related to the Oil and Natural Gas Industry

Oil and natural gas prices are volatile. Declines in prices could adversely affect our financial condition, results of operations, cash flows, access to capital, and ability to grow.

Oil and natural gas prices historically have been volatile and may continue to be volatile in the future. Oil prices could move downward or upward on a rapid or repeated basis, and, as of December 31, 2018, we do not have any commodity derivative contracts that hedge our price risk. The decline since late 2014 in oil and natural gas prices has reduced our revenue, cash flows, and access to capital, and while prices have risen from the lowest levels, prices could decline again in the future. Lower oil and natural gas prices also potentially reduce the amount of oil and natural gas that we can economically produce resulting in a reduction in the proved oil and natural gas reserves we could recognize. Thus, significant and sustained commodity price reductions could materially and adversely affect our financial condition and results of operations which could impact, maintain or increase our current levels of borrowing, our ability to repay current or future indebtedness, refinance our current indebtedness or obtain additional capital on attractive terms.

The markets for crude oil and natural gas have historically been, and are likely to continue to be, volatile and subject to wide fluctuations in response to numerous factors, including the following:

- worldwide and domestic supplies of oil and gas, and the productive capacity of the oil and gas industry as a whole;
- changes in the supply and the level of consumer demand for such fuels;
- overall global and domestic economic conditions;
- political conditions in oil, natural gas, and other fuel-producing and fuel-consuming areas;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for crude oil or natural gas;
- the price and level of imports of crude oil, refined petroleum products, and liquefied natural gas;
- weather conditions, including effects of weather conditions on prices and supplies in worldwide energy markets;
- technological advances affecting energy consumption and conservation;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting countries to agree to and maintain crude oil prices and production controls;
- the competitive position of each such fuel as a source of energy as compared to other energy sources;

- strengthening and weakening of the U.S. Dollar relative to other currencies; and
- the effect of governmental regulations and taxes on the production, transportation, and sale of oil, natural gas, and other fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty, but in general we expect oil and gas prices to continue to fluctuate significantly.

Reserves estimates depend on many assumptions that may turn out to be inaccurate.

Our reserves are estimated by independent petroleum engineers. Any material inaccuracies in our reserves estimates or underlying assumptions could materially affect the quantities and present values of our reserves. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves that we may report. In order to prepare these estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves that we may report. In addition, we may adjust estimates of proved, probable, and possible reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Moreover, there can be no assurance that our reserves will ultimately be produced or that our proved undeveloped, probable, and possible reserves will be developed within the periods anticipated. Any significant variance in the assumptions could materially affect the estimated quantity and value of our reserves.

Investors should not assume that the pre-tax net present value of our proved, probable, and possible reserves is the current market value of our estimated oil and natural gas reserves. We base the pre-tax net present value of future net cash flows from our proved, probable, and possible reserves on prices and costs on the date of the estimate. Actual future prices, costs, and the volume of produced reserves may differ materially from those used in the pre-tax net present value estimate.

Future commodity price declines may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and gas operations. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and natural gas properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each depletion pool to the estimated fair value (discounted future net cash flows of that depletion pool). Any such charge will not affect our cash flow from operating activities or liquidity but will reduce our earnings and shareholders' equity. A decline in oil or natural gas prices from current levels, or other factors, could cause an impairment write-down of capitalized costs and a non-cash charge against future earnings. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date, even if oil or natural gas prices increase.

We may be unable to acquire or develop additional reserves, which would reduce our cash flow and income.

In general, production from oil and natural gas properties declines over time as reserves are depleted, with the rate of decline depending on reservoir characteristics. If we are not successful in our exploration and development activities or in acquiring properties containing reserves, our reserves will generally decline as reserves are produced. Our oil and natural gas production is highly dependent upon our access to capital and our ability to economically find, develop or acquire reserves in commercial quantities.

To the extent cash flow from operations is reduced, either by a decrease in prevailing prices for oil and natural gas or an increase in finding and development costs, and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired. Even with sufficient available capital, our future exploration and development activities may not result in additional reserves, and we might not be able to drill productive wells at acceptable costs.

Our future exploration, development and production activities may not be profitable or achieve our expected returns.

The long-term performance of our business depends upon our ability to identify, acquire and develop additional oil and natural gas reserves that are economically recoverable. Future success depends upon our ability to acquire working and revenue interests in properties upon which oil and natural gas reserves are ultimately discovered in commercial quantities, and the ability to develop prospects that contain additional proven oil and natural gas reserves to the point of production. Without successful acquisition and exploration activities, we will not be able to develop additional oil and natural gas reserves or generate additional revenues. There are no assurances that additional oil and natural gas reserves will be identified or acquired on acceptable terms or that oil and natural gas reserves will be discovered in sufficient quantities to enable us to recover our exploration and development costs or sustain our business.

The successful acquisition and development of oil and natural gas properties requires an assessment of recoverable reserves, future oil and natural gas prices and operating costs, potential environmental and other liabilities, and other factors. Such assessments are inherently uncertain. In addition, no assurance can be given that our exploration and development activities will result in the discovery of additional reserves. Operations may be curtailed, delayed or canceled as a result of lack of adequate capital and other factors, such as lack of availability of rigs and other equipment, title problems, weather, compliance with governmental regulations or price controls, mechanical difficulties, or unusual or unexpected formations, pressures and/or work interruptions. In addition, the costs of exploration and development may materially exceed our internal estimates.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our long-term success depends on the success of our exploration, development and production activities in each of our prospects. These activities are subject to numerous risks beyond our control, including the risk that we will be unable to economically produce our reserves or be able to find commercially productive oil or natural gas reservoirs. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project unprofitable. Further, many factors may curtail, delay or prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- title problems;
- adverse weather conditions;
- lack of market demand for oil and natural gas;
- delays imposed by, or resulting from, compliance with environmental laws and other regulatory requirements;
- declines in oil and natural gas prices; and
- shortages or delays in the availability of drilling rigs, equipment and qualified personnel.

Our future drilling activities might not be successful, and drilling success rates overall or within a particular area could decline. We could incur losses by drilling unproductive wells. Shut-in wells, curtailed production and other production interruptions may materially adversely affect our business, financial condition and results of operations.

The development of proved undeveloped reserves is uncertain. In addition, there are no assurances that our probable and possible reserves will be converted to proved reserves.

Our reserves are estimated by independent petroleum engineers. At December 31, 2018, approximately 47.8% of our total estimated net proved reserves in Turkey were proved undeveloped reserves. Undeveloped reserves, by their nature, are significantly less certain than developed reserves. At December 31, 2018, we also had a significant amount of unproved reserves, which consist of probable and possible reserves. There is significant uncertainty attached to unproved reserves estimates. The discovery, determination and exploitation of undeveloped or unproved reserves requires significant capital expenditures and successful drilling and exploration programs. We do not currently have the funds available to develop our undeveloped reserves. We may not be able to raise the additional capital that we need to develop these reserves. There is no certainty that we will be able to convert undeveloped reserves to developed reserves or unproved reserves into proved reserves or that our undeveloped or unproved reserves will be economically viable or technically feasible to produce.

Legislative and regulatory initiatives and increased public scrutiny relating to fracture simulation activities could result in increased costs and additional operating restrictions or delays.

Fracture stimulation is an important and commonly used process for the completion of oil and natural gas wells and involves the pressurized injection of water and generally sand and/or chemicals into rock formations to contact greater surface area to stimulate production. Recently, there has been increased public concern regarding the potential environmental impact of fracture stimulation activities. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on drinking water supplies, the use of water in connection with completion operations, and the potential for impact to surface water, groundwater and the environment generally.

The increased attention regarding fracture stimulation could lead to greater opposition, including litigation, to oil and natural gas production activities using fracture stimulation techniques. Increased public scrutiny may also lead to additional levels of regulation in the countries in which we operate that could cause operational restrictions or delays, make it more difficult to perform fracture stimulation or could increase our costs of compliance and doing business. Additional legislation or regulation, such as a requirement to disclose the chemicals used in fracture stimulation, could make it easier for third parties opposing fracture stimulation to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. A substantial portion of our operations rely on fracture stimulation, and the adoption of legislation in Bulgaria have placed restrictions on our fracture stimulation activities, causing us to suspend our fracture stimulation activities in Bulgaria. The adoption of legislative or regulatory initiatives in Turkey restricting fracture stimulation could impose operational delays, increased operations costs and additional related burdens on our exploration and production activities which could suspend or make it more difficult to perform fracture stimulation, cause a material decrease in the drilling of new wells and related completion activities and increase our costs of compliance and doing business, which could materially impact our business and profitability.

We are subject to operating hazards.

The oil and natural gas exploration and production business involves a variety of operating risks, including the risk of fire, explosion, blowout, pipe failure, casing collapse, stuck tools, uncontrollable flows of oil or natural gas, abnormally pressured formations and environmental hazards such as oil spills, surface cratering, natural gas leaks, pipeline ruptures, discharges of toxic gases, underground migration, surface spills, mishandling of fracture stimulation fluids, including chemical additives, and natural disasters. The occurrence of any of these events could result in substantial losses to us due to injury and loss of life, loss of or damage to well bores and/or drilling or production equipment, costs of overcoming downhole problems, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Gathering systems and processing facilities are subject to many of the same hazards and any significant problems related to those facilities could adversely affect our ability to market our production.

Our oil and natural gas operations are subject to extensive and complex laws and government regulation in the jurisdictions in which we operate and compliance with existing and future laws may increase our costs or impair our operations.

Our oil and natural gas operations are subject to numerous federal, state, local, foreign and provincial laws and regulations, including those related to the environment, employment, immigration, labor, oil and natural gas exploration and development, payments to local, foreign and provincial officials, taxes and the repatriation of foreign earnings. If we fail to adhere to any applicable federal, state, local, foreign and provincial laws or regulations, or if such laws or regulations restrict exploration or production, or negatively affect the sale, of oil and natural gas, our business, prospects, results of operations, financial condition or cash flows may be impaired. We may be subject to governmental sanctions, such as fines or penalties, as well as potential liability for personal injury, property or natural resource damage and might be required to make significant capital expenditures to comply with federal, state or international laws or regulations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations could adversely affect our business or operations, or substantially increase our costs and associated liabilities.

In addition, exploration for, and exploitation, production and sale of, oil and natural gas in each country in which we operate is subject to extensive national and local laws and regulations requiring various licenses, permits and approvals from various governmental agencies. If these licenses or permits are not issued or unfavorable restrictions or conditions are imposed on our exploration or drilling activities, we might not be able to conduct our operations as planned. Alternatively, failure to comply with these laws and regulations, including the requirements of any licenses or permits, might result in the suspension or termination of operations and subject us to penalties. We incur costs to comply with these numerous laws, regulations, licenses and permits.

Specifically, our oil and natural gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the imposition of administrative, civil and/or criminal penalties, incurring investigatory or remedial obligations and the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to comply in all material respects with applicable environmental laws and regulations, we cannot assure you that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability. We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations.

In addition, many countries have agreed to regulate emissions of "greenhouse gases." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning of oil and natural gas, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for some of our services or products in the future.

We do not plan to insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and natural gas operations.

We do not intend to insure against all risks. Our oil and natural gas exploration and production activities are subject to numerous hazards and risks associated with drilling for, producing and transporting oil and natural gas, and storing, transporting and using explosive materials, and any of the following risks can cause substantial losses:

- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination, underground migration and surface spills or mishandling of fracture stimulation fluids, including chemical additives;
- abnormally pressured formations;

- leaks of oil, natural gas and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, including fracture stimulation activities, or from the gathering and transportation of oil, natural gas and other hydrocarbons, malfunctions of pipelines, processing or other facilities in our operations or at delivery points to third parties;
- spillage or mishandling of oil, natural gas, brine, well fluids, hydraulic fracturing fluids, toxic gas or other pollutants by third-party service providers;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters or other catastrophic events.

As is customary in the oil and natural gas industry, we maintain insurance against some, but not all, of our operating risks. Our insurance may not be adequate to cover potential losses or liabilities and insurance coverage may not continue to be available at commercially acceptable premium levels or at all. We might not elect to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured or under-insured events could require us to make large unbudgeted cash expenditures that could adversely impact our business, financial condition or results of operations.

We might not be able to identify liabilities associated with properties or obtain protection from sellers against them, which could cause us to incur losses.

Our review and evaluation of prospects and future acquisitions might not necessarily reveal all existing or potential problems. For example, inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, may not be readily identified even when an inspection is undertaken. Even when problems are identified, a seller may be unwilling or unable to provide effective contractual protection against all or part of those problems, and we may assume environmental and other risks and liabilities in connection with acquired properties.

We might not be able to obtain necessary permits, approvals or agreements from one or more government agencies, surface owners, or other third parties, which could hamper our exploration, development or production activities.

There are numerous permits, approvals, and agreements with third parties, which will be necessary in order to enable us to proceed with our exploration, development or production activities and otherwise accomplish our objectives. The government agencies in each country in which we operate have discretion in interpreting various laws, regulations, and policies governing operations under the licenses. Further, we may be required to enter into agreements with private surface owners to obtain access to, and agreements for, the location of surface facilities. In addition, because many of the laws governing oil and natural gas operations in the international countries in which we operate have been enacted relatively recently, there is only a relatively short history of the government agencies handling and interpreting those laws, including the various regulations and policies relating to those laws. This short history does not provide extensive precedents or the level of certainty that allows us to predict whether such agencies will act favorably toward us. The governments have broad discretion to interpret requirements for the issuance of drilling permits. Our inability to meet any such requirements could have a material adverse effect on our exploration, development or production activities.

Hedging transactions that we enter into from time to time may expose us to counterparty credit risk.

From time to time, we enter into commodity derivative contracts to hedge the price volatility of oil. These hedging transactions may expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract, and we may not be able to realize the benefit of the derivative contract.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do, which may adversely affect our ability to compete.

We operate in the highly competitive areas of oil and natural gas exploration, development, production and acquisition with a number of other companies, including U.S.-based and foreign companies doing business in each of the countries in which we operate. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in seeking oil and natural gas exploration licenses and production licenses and acquiring desirable producing properties or new leases for future exploration.

Many of our competitors have substantially greater financial, managerial, technological and other resources than we do. These companies are able to pay more for exploratory prospects and productive oil and natural gas properties than we can. To the extent competitors are able to pay more for properties than we are paying, we will be at a competitive disadvantage. Further, many of our competitors enjoy technological advantages over us and may be able to implement new technologies more rapidly than we can. Our ability to explore for and produce oil and natural gas prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Risks Related to Our Common Shares

The interests of our controlling shareholder may not coincide with yours and such controlling shareholder may make decisions with which you may disagree.

As of March 22, 2019, Mr. Mitchell beneficially owned approximately 48% of our outstanding common shares. In addition, persons and entities affiliated with Mr. Mitchell participated in our offering of $46.1 million aggregate principal amount of 12.0% Series A Convertible Redeemable Preferred Shares (the "Series A Preferred Shares") and have the right to convert their Series A Preferred Shares to common shares subject to the terms and conditions of the Series A Preferred Shares. Dalea Partners, LP, an affiliate of Mr. Mitchell, owns 42,000 Series A Preferred Shares; trusts benefitting Mr. Mitchell's four children each own 41,000 Series A Preferred Shares; and Longfellow owns 205,000 Series A Preferred Shares. As a result, Mr. Mitchell could control substantially all matters requiring shareholder approval, including the election of directors and approval of significant corporate transactions. In addition, this concentration of ownership may delay or prevent a change in control of the Company and make some future transactions more difficult or impossible without the support of Mr. Mitchell. The interests of Mr. Mitchell may not coincide with your interests or the interests of our other shareholders.

We may seek to raise additional funds or restructure or increase our debt by issuing securities that would dilute your ownership. Depending on the terms available to us, if these activities result in significant dilution, it may negatively impact the trading price of our common shares.

We may seek to raise additional funds or restructure or increase our debt by issuing common shares, preferred shares, or securities convertible into or exercisable for common shares, that would dilute your ownership. Depending on the terms available to us, if these activities result in significant dilution, it may negatively impact the trading price of our common shares. Further, any additional financing that we secure may require the granting of rights, preferences or privileges senior to, or pari passu with, those of our common shares. Any issuances by us of equity securities may be at or below the prevailing market price of our common shares and in any event may have a dilutive impact on your ownership interest, which could cause the market price of our common shares to decline. We may also raise additional funds through the incurrence of convertible debt or the issuance or sale of other securities or instruments senior to our common shares. If we experience dilution from the issuance of additional securities and we grant superior rights to new securities over common shareholders, it may negatively impact the trading price of our common shares and you may lose all or part of your investment.

The value of our common shares may be affected by matters not related to our own operating performance.

The value of our common shares may be affected by matters that are not related to our operating performance and which are outside of our control. These matters include the following:

- general economic conditions in the United States, Turkey, Bulgaria and globally;
- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and natural gas industry, including environmental regulation and regulation of fracture stimulation activities;
- fluctuation in foreign exchange or interest rates;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;

- failure to obtain industry partner and other third-party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the need to obtain required approvals from regulatory authorities;
- worldwide supplies and prices of, and demand for, oil and natural gas;
- political conditions and developments in each of the countries in which we operate;
- political conditions in oil and natural gas producing regions;
- revenue and operating results failing to meet expectations in any particular period;
- investor perception of the oil and natural gas industry;
- limited trading volume of our common shares;
- announcements relating to our business or the business of our competitors;
- the sale of assets;
- the issuance of common shares, debt or other securities;
- our liquidity;
- our ability to raise additional funds or restructure our debt; and
- loss of key management.

In the past, companies that have experienced volatility in the trading price of their common shares have been the subject of securities class action litigation. We might become involved in securities class action litigation in the future. Such litigation often results in substantial costs and diversion of management's attention and resources and could have a material adverse effect on our business, financial condition and results of operation.

U.S. shareholders who hold common shares during a period when we are classified as a passive foreign investment company may be subject to certain adverse U.S. federal income tax consequences.

Management believes that we are not currently a passive foreign investment company. However, we may have been a passive foreign investment company during one or more of our prior taxable years and could become a passive foreign investment company in the future. In general, classification of our company as a passive foreign investment company during a period when a U.S. shareholder holds common shares could result in certain adverse U.S. federal income tax consequences to such shareholder.

Certain U.S. shareholders who hold common shares during a period when we are classified as a controlled foreign corporation may be subject to certain adverse U.S. federal income tax rules.

Management believes that we currently are a controlled foreign corporation for U.S. federal income tax purposes and that we will continue to be so treated. Consequently, a U.S. shareholder that owns 10% or more of the total combined voting power of all classes of our shares entitled to vote on the last day of our taxable year may be subject to certain adverse U.S. federal income tax rules with respect to the shareholder's investment in us.

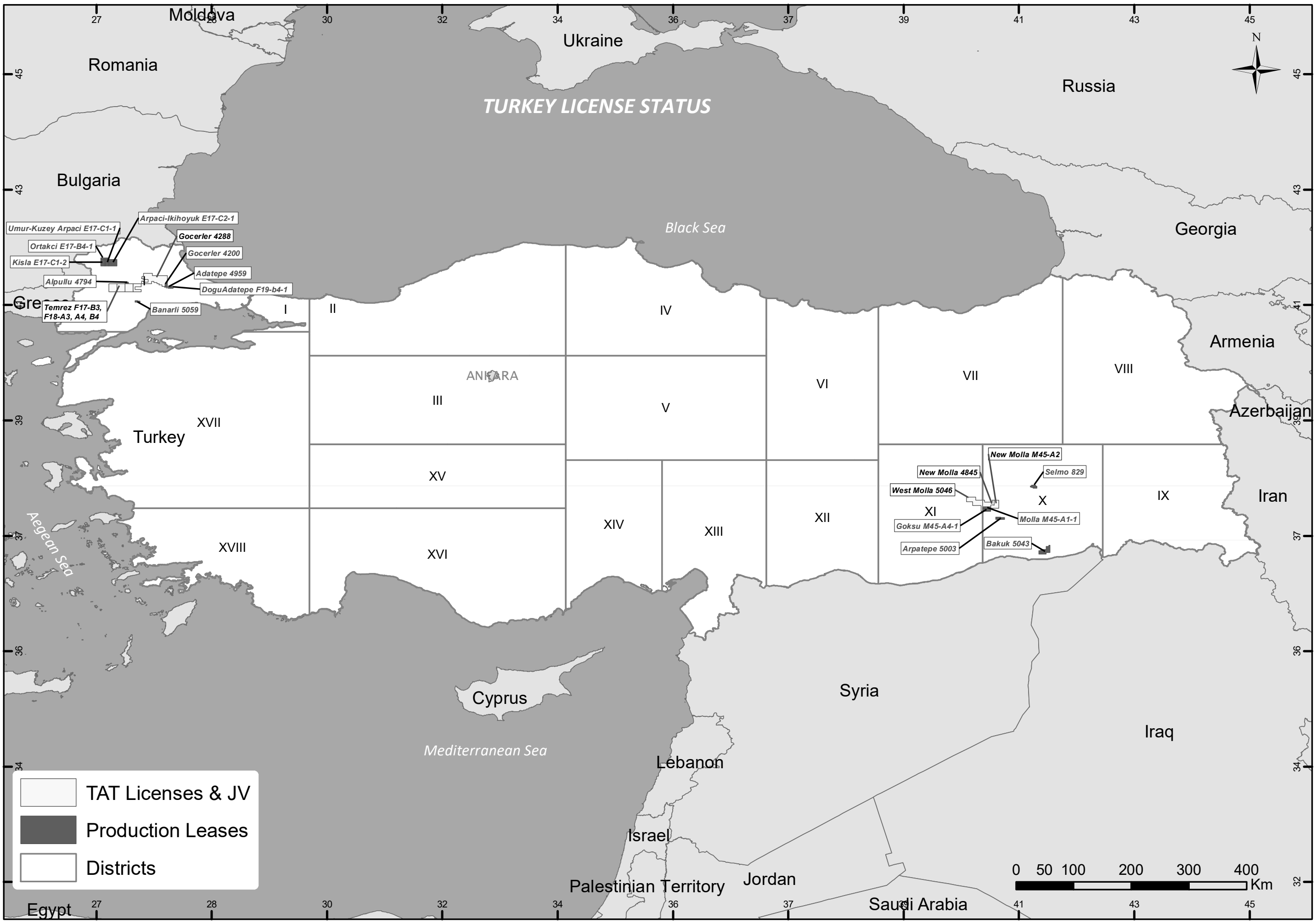
Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Turkey

General. As of December 31, 2018, we held interests in five onshore exploration licenses and 18 onshore production leases covering a total of 443,268 gross (372,050 net) acres in Turkey. We acquired our interests in Turkey through acquisitions, farm-in agreements with existing third-party license holders and applications submitted to the Turkish General Directorate of Mineral and Petroleum Affairs (the “GDMPA”), the agency responsible for the regulation of oil and natural gas activities under the Ministry of Energy and Natural Resources in Turkey. The following map shows our interests in Turkey:



Reserves. As of December 31, 2018, we had total net proved reserves of 9,976 Mbbl of oil and 2,440 Mmcf of natural gas, net probable reserves of 5,748 Mbbl of oil and 817 Mmcf of natural gas and net possible reserves of 6,204 Mbbl of oil and 938 Mmcf of natural gas in Turkey.

Equipment Yards. As of December 31, 2018, we leased equipment yards in Muratli and Diyarbakir and own an equipment yard at Edirne.

Commercial Terms. Turkey’s fiscal regime for oil and natural gas licenses is presently comprised of royalties and income tax. The royalty rate is 12.5%. As of December 31, 2018, the corporate income tax rate was 22%. There is a 5% net profits interest burden for certain of our non-core wells in the Thrace region of Turkey. Dividends repatriated from Turkey would be subject to a withholding tax rate of 15% unless reduced by a tax treaty. There is also an 18% value added tax. However, for exploration licenses, no value added tax is assessed on drilling, completion, workover, seismic and geologic activities.

Licensing Regime. The licensing process in Turkey for oil and natural gas concessions occurs in three stages: permit, license, and lease. Under a permit, the government grants the non-exclusive right to conduct a geological investigation over an area. The size of the area and the term of the permit are subject to the discretion of the GDMPA. A new petroleum law was passed by the Turkish government in May 2013, amending some of the processes related to licensing and operations in Turkey. The regulations concerning implementation were passed by the Turkish government in January 2014. The existing licenses and future licensing processes are currently in a transition phase from the old petroleum law to the new petroleum law. The new law provides that operators have the option to maintain their licenses under the old petroleum law for the duration of the existing terms of a license or to convert their licenses to the new petroleum law prior to the expiration of the license.

The GDMPA awards a license after it approves the applicant's work program, which may include obligations such as geological and geophysical work, seismic reprocessing and interpretation and contingent shooting of seismic and drilling of wells. A license grants exclusive rights over an area for the exploration for and production of petroleum.

Licensing Under the Old Petroleum Law. A license has a term of four years and requires drilling activities by the third year, but this obligation may be deferred into the fourth year by posting a bond. A license is eligible for two separate two-year extensions by fulfilling prior work commitments and subscribing to additional work commitments. A final three-year term may be granted as an appraisal period for any oil or natural gas discovery registered in the previous terms. No single company may own more than an aggregate of 100% of eight licenses within a district. Rentals are due annually based on the size of the license.

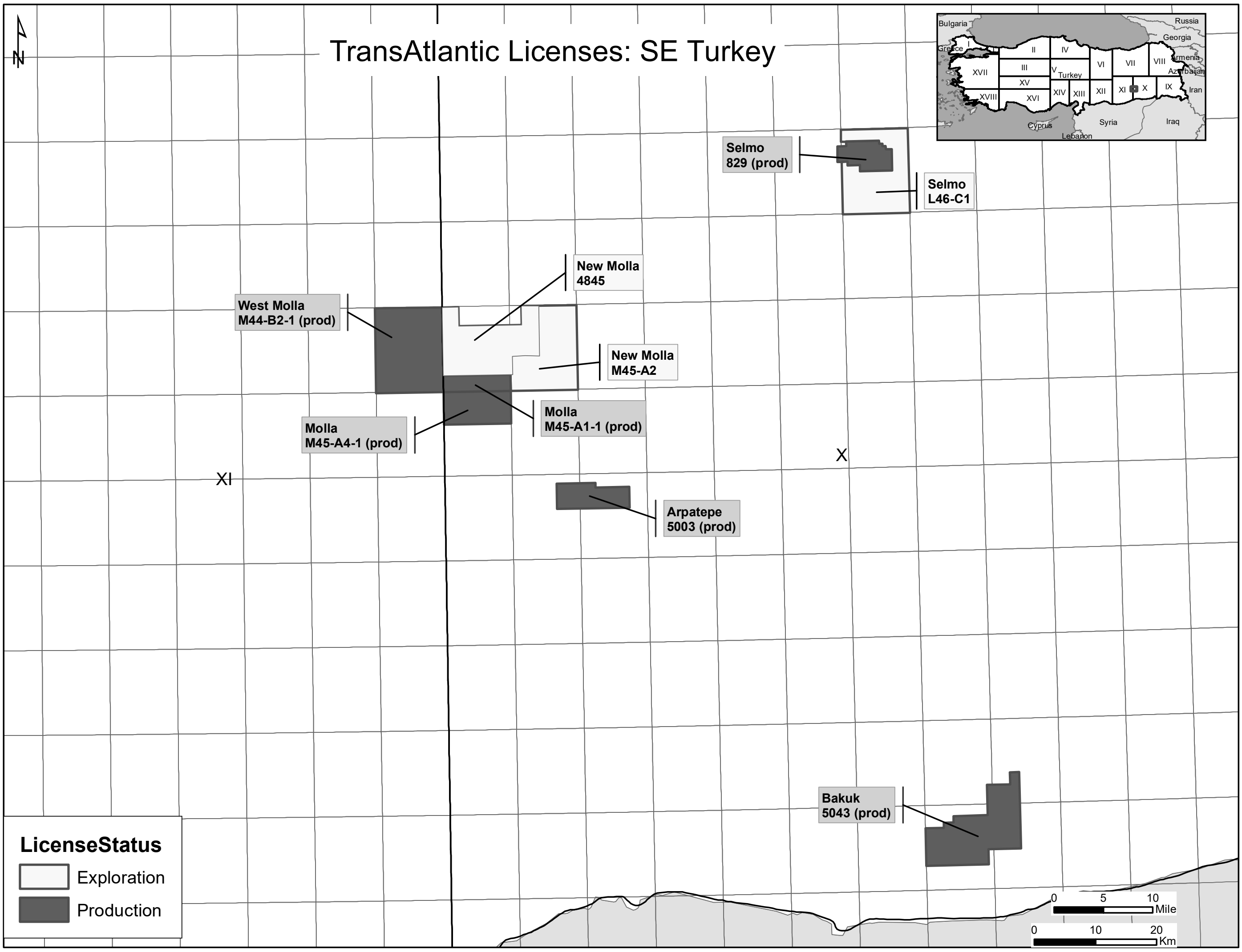
Once a discovery is made, the license holder may apply to convert the area, not to exceed 25,000 hectares (approximately 62,000 acres), to a lease. Under a lease, the lessee may produce oil and natural gas. The term of a lease is for 20 years and may be extended for two further terms of 10 years each. Annual rentals are due based on the size of the lease. The production lease holder is typically able to apply for a new exploration license covering the area of the original exploration license, minus the area of the newly-granted production lease.

Licensing Under the New Petroleum Law. A license has a term of five years and requires the license holder to post a bond equal to 2% of the cost of the work commitments to secure the fulfillment of the work commitments. Licenses shall be based on map sections of scale equal to 1/50,000 (approximately 148,000 acres) or 1/25,000 (approximately 37,000 acres). A license is eligible for two separate two-year extensions by fulfilling prior work commitments and subscribing to additional work commitments including the drilling of at least one well in each separate extension period and providing a bond to secure fulfillment of the additional work commitments. A final two-year term may be granted to appraise a petroleum discovery made during the prior terms. An additional six-month extension may be granted during any of the foregoing terms in order to complete the drilling or testing of a well.

Once a discovery is made, the license holder may apply to convert part of the license area, covering the prospective petroleum field, to a production lease. Under a lease, the lessee may produce oil and natural gas. Based on production level, the term of a lease is for between 5 and 20 years and may be extended up to 40 years in total. The production lease holder is typically able to apply for a new exploration license covering the area of the original exploration license, minus the area of the newly-granted production lease.

The expiration dates reported on our exploration licenses and production leases below are subject to various extensions available under the old petroleum law and the new petroleum law. Those portions of exploration licenses with production are available during any term for conversion to a production lease with a term of between 5 and 20 years plus further extensions if production is maintained. We have converted some of our qualifying acreage into the new petroleum law regulations. Conversion into the new petroleum law provides for the renewal of the exploration license terms for qualifying acreage.

Southeastern Turkey. The following map shows our interests in Southeastern Turkey at December 31, 2018:



Arpatepe (Production Lease 5003). We own a 50% working interest in Production Lease 5003, which covers approximately 11,200 gross acres. For 2018, our wellhead production of oil from the Arpatepe field was 51,127 Bbls of oil, at an average rate of 140 Bbl/d. We are the operator of this production lease, which expires in November 2028, with extensions available under the new petroleum laws.

Bakuk (Production Lease 5043). We own a 50% working interest in Production Lease 5043, which covers approximately 34,400 gross acres. Park Place Energy, Ltd. is the operator of this production lease, which expires in January 2032, with extensions available under the new petroleum laws. The Bakuk-1R well was shut in during 2017 for security precautions and remained shut in during 2018.

Bati Yasince (Production Lease M45-A1-1). We own a 100% operated working interest in Production Lease M45-A1-1, which covers 7,200 gross acres. In 2018, our wellhead production of oil from this production lease was 587 Bbls of oil, at an average rate of 1.60 Bbl/d. We are the operator of this production lease, which expires in December 2019, with extensions available under the new petroleum laws. We expect to apply for extension of this production lease later in 2019.

Göksu (Production Lease M45-A4-1). We own a 100% operated working interest in Production Lease M45-A4-1, which covers approximately 14,500 gross acres. For 2018, our wellhead production of oil from this production lease was 12,809 Bbls of oil, at an average rate of 35 Bbls/d. We are the operator of this production lease, which expires in December 2020, with extensions available under the new petroleum laws.

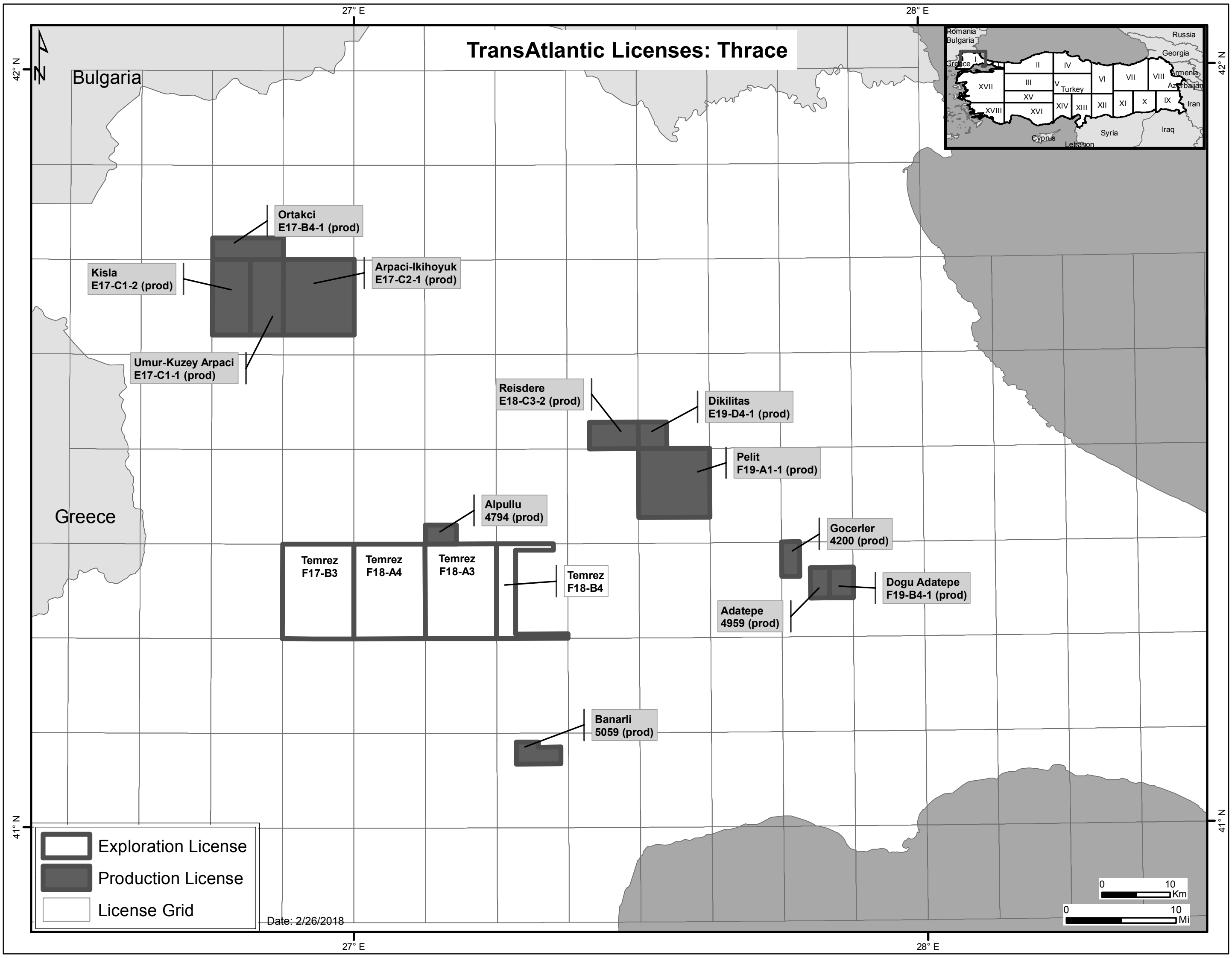
New Molla (Exploration License 4845). We own a 100% operated working interest in the Bahar appraisal wells in Exploration License 4845 and Exploration License M45-A2, which cover approximately 32,700 gross acres. For 2018, our wellhead production of oil from the Bahar appraisal wells was 372,747 Bbls of oil, at an average rate of 1,021 Bbl/d. We are the operator of this exploration license, which expires in March 2019, with extensions available under the new petroleum laws. The production lease application for a portion of this exploration license was submitted in 2017. We drilled the Bahar-8 and Bahar-10 wells, which started producing in 2018, and spud the Dogu (East) Yeniev-1 well with ongoing work-over operations. We also spud the Karagoz-1 well in the M45-A2 portion of this exploration license. Drilling operations are ongoing. In March 2019, we filed a production lease application for the M45-A2 portion of this exploration license.

West Molla (Production Lease M44-B2-1). We own a 100% operated working interest in Production Lease M44-B2-1. In 2018, we converted this license (formerly Exploration License 5046) to a production lease which covers 37,699 gross acres. For 2018, our wellhead production of oil from the wells was 82,371 Bbls of oil, at an average rate of 226 Bbl/d. We are the operator of this production lease, which expires in June 2023, with extensions available under the new petroleum laws. During 2018, we drilled the Yeniev-1 and West Yeniev-1 wells in this production lease. Both wells began producing in 2018.

Selmo (Production Lease 829). We own a 100% operated working interest in Production Lease 829, which covers approximately 8,900 gross acres and includes the Selmo oil field. For 2018, our wellhead production of oil in the Selmo field was 653,719 Bbls of oil, at an average rate of 1,791 Bbl/d. We are the operator of this production lease, which expires in June 2025. In 2018, we drilled the Selmo-81H2 well in this production lease. The well began producing in 2018.

Selmo (Exploration License L46-C1). We own a 100% operated working interest in Exploration License L46-C1, which covers 28,921 gross acres. We are the operator of this exploration license, which expires in November 2023, with extensions available under the new petroleum laws.

Northwestern Turkey. The following map shows our interests in northwestern Turkey at December 31, 2018:



Adatepe (Production Lease 4959). We own a 50% operated working interest in Production Lease 4959, which covers 3,086 gross acres. We are the operator of this production lease, which expires in September 2031, with extensions available under the new petroleum laws.

Alpullu (Production Lease 4794) and Temrez (Exploration Licenses F17B3, F18A3, F18A4, and F18B4). We own a 100% operated working interest in this production lease and these exploration licenses, which cover 3,158 acres and 119,866 acres, respectively. We are the operator of this production lease and these exploration licenses, which expire in September 2028 and July 2020, respectively, with extensions available under the new petroleum laws. We may drill wells on Exploration License F18-B4 in 2019.

Banarli (Production Lease 5059). We own a 50% operated working interest in Production Lease 5059, which covers 4,608 gross acres. We plan to maintain production to satisfy our obligation on this production lease. We are the operator of this production lease, which expires in February 2032, with extensions available under the new petroleum laws.

Dogu Adatepe (Production Lease F19-B4-1). We own a 50% working interest in Production Lease F19-B4-1, which covers part of our former Cayirdere license and approximately 4,000 gross acres. TPAO is the operator of this production lease, which expires in October 2020, with an additional 32 years of extensions under the new petroleum laws available with the maintenance of production on the lease.

Edirne (Production Leases Ortaki E17-B4-1, Arpaci-Ikihoyur E17-C2-1, and Umur-Kuzey Arpaci E17-C1-1) and Habiller (Production Lease Kisla E17-C1-2). We own a 55% operated working interest in Production Leases Ortaki E17-B4-1, Arpaci-

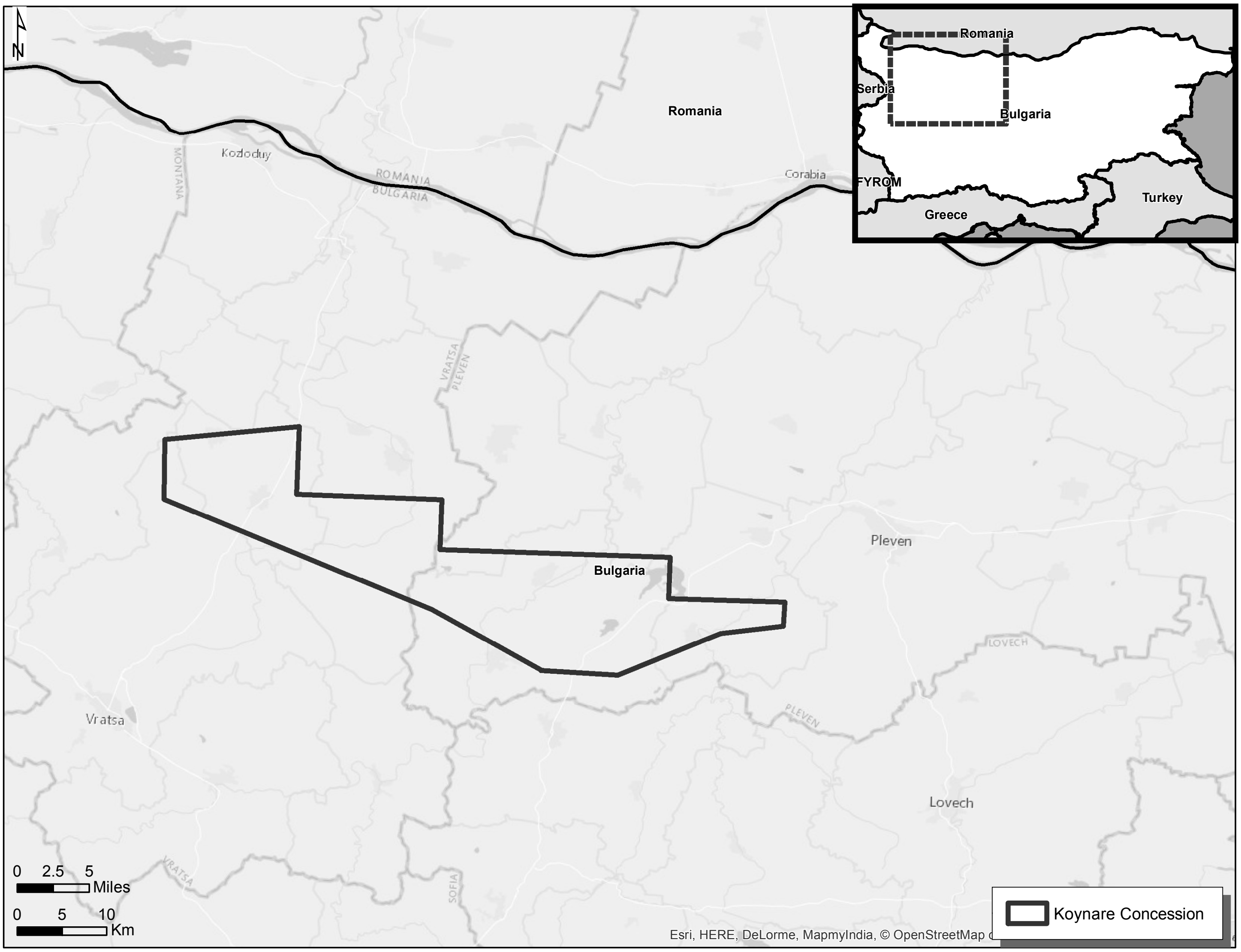
Ikihoyur E17-C2-1, and Umur-Kuzey Arpaci E17-C1-1 and a 100% operated working interest in Production Lease Kisla E17-C1-2, which cover an aggregate of approximately 65,000 gross acres. We are the operator of these production leases, which each expire in 2020, with extensions available under the new petroleum laws. Gas production was shut in for most of 2017. We converted our gas sales system from high pressure to low pressure and resumed gas sales in 2018.

Gocerler (Production Lease 4200 and Production Leases E18-C3-2, E19-D4-1, and F19-A1-1). We own a 50% operated working interest in Production Lease 4200 and Production Leases E18-C3-2, E19-D4-1, and F19-A1-1, which cover approximately 3,363 gross acres and 37,000 gross acres, respectively. We are the operator of these production leases, which expire in May 2023 and August 2021 through August 2025, respectively, with extensions available under the new petroleum laws.

In 2018, our net wellhead production was 238,865 Mcf at an average rate of 654 Mcf/d. from all the gas fields listed above.

Bulgaria

General. As of December 31, 2018, we operated and held interests in one production concession in Bulgaria. In January 2012, the Bulgarian Parliament enacted legislation that banned the fracture stimulation of oil and natural gas wells in the Republic of Bulgaria. The legislation also had the effect of preventing conventional drilling and completion activities. In June 2012, the Bulgarian Parliament amended the legislation to clarify that conventional drilling and completion activities were not intended to be affected by the law. As long as this legislation remains in effect, completion activity, production from our cased cemented existing wells, and our unconventional natural gas exploration, development, and production activities in Bulgaria will be significantly constrained. The following map shows our interests in Bulgaria at December 31, 2018:



Reserves. As of December 31, 2018, there were no reserves associated with our properties in Bulgaria.

Commercial Terms. Bulgaria's petroleum laws provide a framework for investment and operation that allows foreign investors to retain the proceeds from the sale of petroleum production. The fiscal regime is comprised of royalties and income tax.

The royalty ranges from 2.5% to 30%, based on an "R factor" which is particular to each production concession agreement, but is typically calculated by dividing the total cumulative revenues from a production concession by the total cumulative costs incurred for that production concession.

The production concession holder pays Bulgarian corporate income tax, which is assessed at a rate of 10%. All costs incurred in connection with exploration, development, and production operations are deductible for corporate income tax purposes.

Resident companies which remit dividends outside of Bulgaria are subject to a dividend withholding tax between 10% and 15%, depending on the proportion of the capital owned by the recipient. No customs duty is payable on the export of petroleum, however a customs duty may be payable on the import of material necessary to conduct petroleum operations in certain conditions. There is also a 20% value added tax. Oil is priced at market while natural gas is tied to a bundle pricing based in part on the import price and in part on the domestic price.

Licensing Regime. The licensing process in Bulgaria for oil and natural gas concessions occurs in two stages: exploration permit and then production concession.

Under an exploration permit, the government grants exploration rights for a term of up to five years to conduct seismic and other exploratory activities, including drilling. The recipient of an exploration permit commits to a work program and posts a bank guarantee in the amount of 10% of the estimated cost for the program. The area covered by an onshore exploration permit may be as large as 5,000 square kilometers. The exploration permit may be extended for up to two additional two-year terms, subject to fulfillment of minimum work programs, and may be extended for an additional one-year term in order to appraise potential geologic discoveries. Interests under an exploration permit are transferable, subject to government approval. The permit holder is required to pay an annual area fee equal to 40 Bulgarian Lev (approximately \$23 at December 31, 2018) per square kilometer, or 40 Bulgarian Lev (approximately \$23 at December 31, 2018) per square kilometer in the event the permit term is extended.

Upon the registration of a commercial discovery, an exploration permit holder may apply for a production concession. The production concession size corresponds to the area of the commercial discovery. The duration of a production concession is 35 years and may be extended by a further 15 years subject to the terms and conditions of the production concession agreement. Interests under a production concession are transferable, subject to government approval. No bonus is paid to the government by us upon conversion to a production concession.

Koynare. We own a 100% working interest, subject to a 3.02% overriding royalty interest, in the Koynare production concession covering approximately 163,000 acres. The Koynare Concession Area contains the Devinci-R1 well, where we discovered a reservoir in the Jurassic-aged Ozirovo formation at a depth of approximately 13,800 feet, which the Bulgarian government has certified as a geologic and commercial discovery. We commenced the side-track and re-drilling of the Deventci R-1 well in December 2018, targeting the Ozirovu and Dolmi Dabnik formations. The well was drilled to a total depth of 16,450 feet. Although we encountered the targeted formations, tests did not indicate commercial quantities of reservoir quality rock. We are currently evaluating future activity in Bulgaria. For purposes of our royalty conversion under the “R” factor, we have a cost recovery pool of approximately \$44.33 million at December 31, 2018.

Summary of Oil and Natural Gas Reserves

The following table summarizes our net proved, probable, and possible reserves at December 31, 2018.

	Reserves		
	Oil and Condensate (Mbbl)	Natural Gas (Mmcf)	Total (Mboe)
Reserves Category			
Total (1)			
Proved reserves			
Proved developed	5,047	2,256	5,423
Proved undeveloped	4,929	184	4,960
Total proved	9,976	2,440	10,383
Probable reserves			
Probable developed	901	787	1,032
Probable undeveloped	4,847	30	4,852
Total probable	5,748	817	5,884
Possible reserves			
Possible developed	1,132	906	1,283
Possible undeveloped	5,072	32	5,077
Total possible	6,204	938	6,360

(1) All of our reserves are located in Turkey

Value of Proved Reserves

The following table shows our estimated future net revenue, Standardized Measure, and PV-10 as of December 31, 2018:

	Total (in thousands)
Future net revenue	$ 479,775
Total Standardized Measure (1)	$ 266,157
Total PV-10 (2)	$ 320,625

(1) DeGolyer and MacNaughton did not estimate the Standardized Measure.
(2) The PV-10 value of the estimated future net revenue is not intended to represent the current market value of the estimated oil and natural gas reserves we own. Management believes that the presentation of PV-10, while not a financial measure in accordance with U.S. GAAP, provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes estimated to be paid, the use of a pre-tax measure is valuable when comparing companies based on reserves. PV-10 is not a measure of financial or operating performance under U.S. GAAP. PV-10 should not be considered as an alternative to the Standardized Measure as defined under U.S. GAAP. The Standardized Measure represents the PV-10 after giving effect to income taxes. The following table provides a reconciliation of our PV-10 to our Standardized Measure:

	Total (in thousands)
Total PV-10	$ 320,625
Future income taxes (1)	(77,533)
Discount of future income taxes at 10% per annum (1)	23,065
Standardized Measure (1)	$ 266,157

(1) DeGolyer and MacNaughton did not estimate future income taxes, the discount of future income taxes at 10% per annum, or the Standardized Measure.

Proved Reserves

Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors. See “Oil and Natural Gas Reserves under U.S. Law.”

At December 31, 2018, our estimated proved reserves were 10,383 Mboe, a decrease of 5,093 Mboe, or 33%, compared to 15,476 Mboe at December 31, 2017. This decrease was primarily attributable to revisions of previously estimated recoveries from planned wells in the Selmo field following revisions to our drilling plans in light of the expiration of our Selmo production lease in 2025, which resulted in a decrease of 3,680 Mboe, and from planned wells in the Bahar field following the establishment of the oil/water contact for the Bahar field, which resulted in a decrease of 2,618 Mboe. Additionally, proved reserves decreased 1,055 Mboe for volumes sold. This decrease was partially offset by a 2,045 Mboe increase in proved reserves due to the discovery of productive pay in the Yeniev oil field.

Proved Undeveloped Reserves

At December 31, 2018, our estimated proved undeveloped reserves were 4,960 Mboe, a decrease of 5,821 Mboe, or 54%, compared to 10,781 Mboe at December 31, 2017. The decrease in proved undeveloped reserves was primarily attributable to revisions of previously estimated recoveries from planned wells in the Selmo field following revisions to our drilling plans in light of the expiration of our Selmo production lease in 2025, which resulted in a decrease of 3,680 Mboe, and from planned wells in the Bahar field following the establishment of the oil/water contact for the Bahar field, which resulted in a decrease of 2,618 Mboe. This decrease was partially offset by a 1,373 Mboe increase in proved undeveloped reserves due to the discovery of productive pay in the Yeniev oil field. All of our proved undeveloped reserves as of December 31, 2018 will be developed within five years of the date the reserve was first disclosed as a proved undeveloped reserve. The estimated undiscounted capital costs associated with our proved undeveloped reserves in Turkey is $56.0 million.

The proved undeveloped reserves assume development costs will be funded from future cash flows from operations and financing activities, which may not be sufficient or available at commercially economic terms and could impact the timing of these development activities.

Probable Reserves

Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes, and other factors. See "—Oil and Natural Gas Reserves under U.S. Law."

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Possible Reserves

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes, and other factors. See "—Oil and Natural Gas Reserves under U.S. Law."

When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Internal Controls

Management has established, and is responsible for, a number of internal controls designed to provide reasonable assurance that the estimates of proved, probable, and possible reserves are computed and reported in accordance with rules and regulations provided by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls consist of documented process workflows and qualified professional engineering and geological personnel with specific reservoir experience. We also retained an outside independent engineering firm to prepare estimates of our proved, probable, and possible reserves for Turkey. We work closely with this firm, and management is responsible for providing accurate operating and technical data to it. Management has tested the processes and controls regarding our reserves estimates for 2018. Senior management reviews and approves our reserves estimates, whether prepared internally or by third parties. In addition, our audit committee serves as our reserves committee and is composed of three outside directors, all of whom have experience in the review of energy company reserves evaluations. The audit committee reviews the final reserves estimate and also meets with representatives from the outside engineering firm to discuss their process and findings.

Oil and Natural Gas Reserves under U.S. Law

In the United States, we are required to disclose proved reserves, and we are permitted to disclose probable and possible reserves, using the standards contained in Rule 4-10(a) of the SEC's Regulation S-X. The estimates of proved, probable, and possible reserves presented as of December 31, 2018 for Turkey have been prepared by DeGolyer and MacNaughton, our external engineers. The technical person at DeGolyer and MacNaughton that is primarily responsible for overseeing the preparation of our reserves estimates is a Registered Professional Engineer in the State of Texas and has a Bachelor of Science degree in Petroleum Engineering from Texas A&M University. He has over 34 years of experience in oil and natural gas reservoir studies and evaluations and is a member of the Society of Petroleum Engineers.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with DeGolyer and MacNaughton to ensure the integrity, accuracy and timeliness of data furnished to them for the preparation of their reserves estimates. Our vice president of engineering has over 11 years of experience in oil and natural gas reservoir studies and evaluations. He has a BASC (Engineering) from the University of British Columbia and is a registered Professional Engineer (Alberta).

Estimates of oil and natural gas reserves are projections based on a process involving an independent third-party engineering firm's collection of all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely upon various assumptions, including assumptions required by the SEC, such as constant oil and natural gas prices, operating expenses and future capital costs. We also make assumptions relating to availability of funds and timing of capital expenditures for development of our proved undeveloped, probable, and possible reserves. These reports should not be construed as the current market value of our reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the reserves will ultimately be realized. Our actual results could differ materially. See "Supplemental Information-Supplemental oil and natural gas reserves information (unaudited)" to our consolidated financial statements for additional information regarding our oil and natural gas reserves.

The technologies and economic data used in the estimation of our proved, probable, and possible reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

The estimates of proved, probable, and possible reserves prepared by DeGolyer and MacNaughton for the year ended December 31, 2018 included a detailed evaluation of our Selmo, Arpatepe, Bakuk, Molla, and certain Thrace Basin properties in Turkey. DeGolyer and MacNaughton determined that their estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about whether proved reserves are economically producible from a given date forward, under existing economic conditions, operating methods and government regulations, consistent with the definition in Rule 4-10(a)(24) of SEC Regulation S-X.

Oil and Natural Gas Reserves under Canadian Law

As a reporting issuer under Alberta, British Columbia and Ontario securities laws, we are required under Canadian law to comply with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") implemented by the members of the Canadian Securities Administrators in all of our reserves related disclosures. DeGolyer and MacNaughton evaluated our reserves as of December 31, 2018 for Turkey in accordance with the reserves definitions of NI 51-101 and the Canadian Oil and Gas Evaluators Handbook ("COGEH"). Our annual oil and natural gas reserves disclosures prepared in accordance with NI 51-101 and COGEH and filed in Canada are available at www.sedar.com.

Oil and Natural Gas Sales Volumes

The following table sets forth our sales volumes of oil and natural gas (including by field for any field that contained 15% or more of our total proved reserves) for 2018 and 2017:

	Sales Volumes		
Year	Oil (1) (Bbls)	Natural Gas (Mcf)	Total (Boe)
2018			
Turkey	1,020,144	211,686	1,055,425
Selmo field	570,189	–	570,189
Bahar field	322,129	–	322,129
Total Turkey	1,020,144	211,686	1,055,425
2017			
Turkey	1,103,947	311,224	1,155,818
Selmo field	593,425	–	593,425
Bahar field	437,481	–	437,481
TBNG (2)	88	64,730	10,876
Total Turkey	1,104,035	375,954	1,166,694

(1) "Oil" volumes include condensate (light oil) and medium crude oil.

(2) TBNG is reported separately due to the sale of the ownership interests in TBNG in February 2017.

Average Sales Price and Production Costs

The following table sets forth the average sales price per Bbl of oil and Mcf of natural gas and the average production cost, not including ad valorem and severance taxes, per unit of production for each of 2018 and 2017:

	2018	2017
Turkey:		
Average Sales Price Oil ($/Bbl)	$ 67.84	$ 48.65
Natural Gas ($/Mcf)	$ 5.01	$ 4.81
Unit Costs Production ($/Boe)	$ 8.93	$ 9.16

Drilling Activity

The following table sets forth the number of net productive and dry exploratory wells and net productive and dry development wells we drilled in 2018 and 2017:

	Development Wells		Exploratory Wells	
	Productive	Dry	Productive	Dry
Turkey:				
2018	3.0	–	2.0	–
2017	2.0	–	–	–
Bulgaria:				
2018	–	–	–	–
2017	–	–	–	–

Oil and Natural Gas Properties, Wells, Operations and Acreage

Productive Wells. The following table sets forth the number of productive wells (wells that were producing oil or natural gas or were capable of production) in which we held a working interest as of December 31, 2018:

	Oil		Natural Gas	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Turkey	73.0	71.0	32.0	21.2
Bulgaria	–	–	–	–

(1) "Gross wells" means the wells in which we held a working interest (operating or non-operating).
(2) "Net wells" means the sum of the fractional working interests owned in gross wells.

Developed Acreage. The following table sets forth our total gross and net developed acreage as of December 31, 2018:

	Developed Acres	
	Gross (1)	Net (2)
Turkey	234,139	162,921
Bulgaria	–	–
Total	234,139	162,921

(1) "Gross" means the total number of acres in which we had a working interest.
(2) "Net" means the sum of the fractional working interests owned in gross acres.

Undeveloped Acreage. The following table sets forth our undeveloped land position as of December 31, 2018:

	Undeveloped Acres	
	Gross (1)	Net (2)
Turkey	209,129	209,129
Bulgaria	162,800	162,800
Total	371,929	371,929

(1) "Gross" means the total number of acres in which we had a working interest.
(2) "Net" means the sum of the fractional working interests owned in gross acres.

Undeveloped Acreage Expirations. The following table summarizes by year our undeveloped acreage as of December 31, 2018 that is scheduled to expire in the next five years:

	Undeveloped Acres		% of Total Undeveloped Acres
	Gross (1)	Net (2)	Net (2)
2019	60,342	60,342	16.2
2020	119,866	119,866	32.2
2021	-	-	–
2022	-	-	–
2023	28,922	28,922	7.8

(1) "Gross" means the total number of acres in which we had a working interest.
(2) "Net" means the sum of the fractional working interests owned in gross acres.

We anticipate that we will be able to extend the license terms for substantially all of our undeveloped acreage in Turkey scheduled to expire in 2019 through the execution of our current work commitments.

Item 3. Legal Proceedings

TEMI Litigation. TEMI has been involved in a number of lawsuits with a group of villagers living around the Selmo oil field who claim ownership of a portion of the surface at Selmo in order to claim a legal right with respect to the receipt of surface use damages and land rental fees. These cases are being vigorously defended by TEMI and Turkish government authorities. We do not have enough information to estimate the potential additional operating costs we could incur in the event the purported surface owners' claims are ultimately successful. The following is a summary of these cases.

In 2003, the villagers applied to the Kozluk Civil Court of First Instance in Turkey with seven title survey certificates dating back to Ottoman times. These villagers were granted title registration certificates, and in 2005, these villagers applied to the Kozluk Civil Court of First Instance to enlarge the areas covered by the certificates to approximately 20 square kilometers. Neither we nor, to our knowledge, any ministry in the Turkish government received notice of this court proceeding. Almost all of our production wells at the Selmo oil field lie within this enlarged area. In 2009, the Supreme Court overruled the Kozluk Civil Court of First Instance and directed it to re-examine the case (the "Surface Litigation"). On June 27, 2012, the Kozluk Civil Court of First Instance dismissed the Surface Litigation. The court issued its formal decision on August 8, 2012, and the plaintiffs filed an appeal with the Court of Appeal. The decision was reversed by the Court of Appeal and sent back to the Kozluk Civil Court of First Instance in August 2014. The Court of Appeals ruled that the Kozluk Civil Court of First Instance investigate the merits of the dispute to determine the ownership position of the parties, that TPAO should be added as a party to the litigation, and that the cadastral map sheet depicting the real properties at issue must be investigated. The parties then appealed to the Court of Appeals for correction of judgment. The file was reversed by the Court of Appeal and sent back to the Kozluk Cadastre Court in April 2018.

In 2006, the Turkish Forestry Authority filed a claim in the Kozluk Cadastre Court against the villagers for attempting to register land that is registered with the Turkish government as forest. TEMI joined the Turkish government as a plaintiff in that case. In February 2011, the Kozluk Cadastre Court decided to suspend the case until there is a resolution of the Surface Litigation.

In addition, TEMI is a defendant in two nuisance cases filed in the Kozluk Cadastre Court and two claims for damages filed in the Kozluk Civil Court of First Instance. The plaintiffs in the nuisance cases are the same villagers in the Surface Litigation. The plaintiff in the damages cases is a single villager. The Turkish Treasury Department and the Turkish Forestry Authority have joined TEMI as defendants in each of these cases. The Kozluk Cadastre Court has decided to suspend each of the nuisance cases until there is a resolution of the Surface Litigation. On December 27, 2012, the Kozluk Civil Court of First Instance dismissed the first damages case, and the plaintiff appealed that decision. In June 2015, the Court of Appeal reversed that decision and sent the case back to the Kozluk Civil Court of First Instance. In May 2016, the Kozluk Civil Court of First Instance decided to merge the two damages cases (as the parties and the facts underlying each damages case are substantially the same and the primary difference is the time period for which the plaintiff is seeking damages) and suspend the merged damages case until there is a resolution of the Surface Litigation.

We continue to operate on the surface at Selmo and have paid surface damages and rentals for locations at Selmo from the time we began operating the Selmo lease to present.

Bulgarian Minister of Energy. 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. In November 2018, the Sofia Court of Appeal concluded that the judgement of the Sofia City Court was correct and, therefore, dismissed the Bulgarian Minister of Energy's appeal. In January 2019, the Bulgarian Minister of Energy filed an appeal in the Supreme Court of Cassation. We continue to vigorously defend this claim.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Common Shares and Dividends

As of March 22, 2019, we had 52,496,666 common shares issued and outstanding and held by 169 record holders, including nominee holders such as banks and brokerage firms who hold shares for beneficial owners.

We have not declared any dividends to date on our common shares. We have no present intention of paying any cash dividends on our common shares in the foreseeable future, as we intend to use cash flow from operations to invest in our business.

Foreign Exchange Control Regulations

We have been designated as a non-resident for Bermuda exchange control purposes by the Bermuda Monetary Authority. Because of this designation, there are no restrictions on our ability to transfer funds in and out of Bermuda.

The transfer of shares between persons regarded as residents outside Bermuda for exchange control purposes and the sale of our common shares to or by such persons may take place without specific consent under the *Exchange Control Act 1972*. Issuances and transfers of shares involving any person regarded as a resident in Bermuda for exchange control purposes require specific approval under the *Exchange Control Act 1972*.

As an “exempted company,” we are exempt from Bermuda laws which restrict the percentage of share capital that may be held by non-Bermuda residents, but as an exempted company, we may not participate in certain business transactions, including: (1) the acquisition or holding of land in Bermuda (except that required for our business and held by way of lease or tenancy for terms of not more than 50 years) without the express authorization of the Bermuda legislature, (2) the taking of mortgages on land in Bermuda to secure an amount in excess of $50,000 without the consent of the Minister of Finance, (3) the acquisition of any bonds or debentures secured by any land in Bermuda, other than certain types of Bermuda government securities, or (4) the carrying on of business of any kind in Bermuda, except in furtherance of our business carried on outside Bermuda.

Item 6. Selected Financial Data

Not applicable.

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

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 December 31, 2018, we held interests in 372,050 and 162,500 net acres of developed and undeveloped oil and natural gas properties in Turkey and Bulgaria, respectively. As of March 22, 2018, approximately 48% of our outstanding common shares were beneficially owned by Mr. Mitchell, the chairman of our board of directors and our chief executive officer.

2018 Financial and Operational Performance

- We derived 97.8% of our revenues from the production of oil and 1.5% of our revenues from the production of natural gas during the year ended December 31, 2018.
- Total oil and natural gas sales revenues increased 26.6% to $70.3 million for the year ended December 31, 2018, compared to $55.5 million in 2017. The increase was primarily the result of an increase in our average realized price which increased $19.00 to $66.58 per Boe in 2018 compared to $47.58 per Boe in 2017, resulting in a $16.0 million increase in revenue. Additionally, revenues increased $4.7 million due to revenue reporting regulation ASC 606. This was partially offset by a decrease in sales volumes of 112 Mboe, which resulted in lower revenues of $5.9 million.
- Wellhead production was 1,020 Mbbls of oil and 212 Mmcf of natural gas for the year ended December 31, 2018, as compared to 1,104 Mbbls of oil and 376 Mmcf of natural gas for 2017.
- In 2018, we incurred $23.7 million in total capital expenditures, including license acquisition, seismic and corporate expenditures, as compared to $20.6 million in total capital expenditures in 2017.
- As of December 31, 2018, we had no long-term debt, $22.0 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 Series A Preferred Shares as of December 31, 2017.

2018 Operations

Southeastern Turkey

We drilled the Selmo-81H2 well to a total depth of 5,770 feet for a drilling cost of approximately $3.7 million. Due to issues encountered while drilling, we completed the well vertically and established commercial production of 68 bbl/d.

We drilled the Bahar-8 well to a total depth of 10,650 feet for a drilling cost of approximately $3.1 million. The well was put on production at an initial rate of 55 bbl/d from the Hazro F4 formation.

We drilled the Bahar-10 well to a total depth of 10,790 feet for a drilling cost of approximately $2.3 million. The well was put on production at an initial rate of 145 bbl/d from the Hazro F3A formation.

We drilled the Yeniev-1 well to a total depth of 10,306 feet for a drilling cost of approximately $3.8 million. The well encountered hydrocarbon shows in the Mardin and Bedinan formations. The well was a discovery on a new structure in the Molla area with the potential for a significant number of future offset drilling locations. By natural flow, the well produced 68,427 bbl (350 bbl/d) through December 31, 2018.

We drilled the West Yeniev-1 well to a total depth of 9,625 feet for a drilling cost of approximately $3.0 million. The well encountered hydrocarbon shows in the Mardin and Bedinan formations and had an initial stabilized rate of 339 bbl/d producing naturally under a 16/64" choke.

We drilled the East Yeniev-1 well to a total depth of 9,900 feet for a drilling cost of approximately $1.9 million. The well encountered hydrocarbon shows in the Mardin and Bedinan formations. Completion operations began in January 2019 and resulted in a discovery in the Mardin formation.

The Cavuslu-1 well was put on production at an initial production rate of 31 Boped from the Mardin formation. Additional oil that was tested in the Bedinan and Dadas formations will be added after a long-term test period.

The Pinar-1 well had been intermittently producing due to a mechanical blockage in the well. The equipment causing the blockage was recovered in the third quarter of 2018, and the well was fracture stimulated in the Bedinan formation. The well was put on production with an initial production rate of 65 bbl/d.

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

Northwestern Turkey

We did not engage in any new drilling activities in northwestern Turkey during 2018.

Bulgaria

We commenced the side-track and re-drilling of the Deventci R-1 well in December 2018, targeting the Ozirovu and Dolmi Dabnik formations.

Current Operations

Southeastern Turkey

Molla

Yeniev Field. Both the Yeniev-1 and West Yeniev-1 wells continue flowing naturally with little water. In November 2018, we spud the East Yeniev-1 appraisal well to further delineate the structure. The well was drilled to a total measured depth of 9,900 feet and encountered hydrocarbon shows in the Mardin and Bedinan formations. Completion operations began in January 2019.

Other. We spud the Blackeye-1 well in January 2019. The well was drilled to a total measured depth of 11,105 feet and encountered oil shows in the Hazro, Mardin, and Bedinan formations. Completion operations began in February 2019.

Selmo

We have completed the initial phase of operations in the Selmo-1 well to re-enter and test the Permian formation, establishing the productivity of the Permian formation. During a short-term flow test of a previously untested interval, the Selmo-1 well tested 45.6 API condensate along with natural gas containing a high carbon dioxide percentage component. While the Selmo-1 well lies in what is interpreted as the gas cap of the structure, the positive test results warrant further testing lower on the structure.

Northwestern Turkey

Thrace Basin BCGA

We continue to evaluate our prospects in the Thrace Basin's Basin Center Gas Accumulation ("Thrace Basin BCGA") in light of the recent 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.

Subsequent to drilling and testing of the Yamalik-1 well, the joint venture between Valeura and Equinor announced a three-well program. In the first quarter of 2019, Valeura and Equinor announce that they drilled and cased a second well in the Thrace Basin BCGA, the Inanli-1 well. According to Valeura and Equinor, the well was drilled to a total depth of 4,885 meters and encountered 1,615 meters of high net -to-gross sandstone, which they interpreted to contain over-pressured gas. Valeura and Equinor announced that they expect to complete the well in the first quarter of 2019. In the first quarter of 2019, Valeura and Equinor announced that they spud the Devepinar-1 appraisal well and drilled it to intermediate casing point at 3,375 meters. According to Valeura and Equinor, the Devepinar-1 appraisal well is designed as a 20-kilometer step-out well to test the lateral extent of the Thrace Basin BCGA.

We expect to spud a shallow exploration well on our license in the Thrace Basin in the second quarter of 2019.

Bulgaria

We commenced the side-track and re-drilling of the Deventci R-1 well in December 2018, targeting the Ozirovu and Dolmi Dabnik formations. The well was drilled to a total depth of 16,450 feet. Although we encountered the targeted formations, tests did not indicate commercial quantities of reservoir quality rock. We are currently evaluating future activity in Bulgaria.

Planned Operations

We expect our net field capital expenditures for 2019 to range between $25.0 million and $30.0 million. We expect net field capital expenditures during 2019 to include between $24.0 million and $29.0 million in drilling and completion expense for 10 planned wells and approximately $1.0 million for recompletions. We expect that cash on hand and cash flow from operations will be sufficient to fund our 2019 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2019 capital expenditure budget is subject to change.

Critical Accounting Policies

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 consolidated financial statements included in this Annual Report on Form 10-K. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which 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.

We believe the following critical accounting policies affect the significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties. In accordance with the successful efforts method of accounting for oil and natural gas properties, costs of productive wells, developmental dry holes and productive leases are capitalized into appropriate groups of properties based on geographical and geological similarities. Acquisition costs of proved properties are amortized using the unit-of-production method based on total proved reserves, and exploration well costs and additional development costs are amortized using the unit-of-production method based on proved developed reserves. Proceeds from the sale of properties are credited to property costs, and a gain or loss is recognized when a significant portion of an amortization base is sold or abandoned. Exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged to expense as incurred. Exploratory drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to exploration expense if and when the well is determined to be non-productive. The determination of an exploratory well’s ability to produce generally must be made within one year from the completion of drilling activities. The acquisition costs of unproved acreage are initially capitalized and are carried at cost, net of accumulated impairment provisions, until such leases are transferred to proved properties or charged to exploration expense as impairments of unproved properties.

Impairment of Long-Lived Assets. We follow the provisions of Accounting Standards Codification (“ASC”) 360, *Property, Plant and Equipment* (“ASC 360”). ASC 360 requires that our long-lived assets be assessed for potential impairment of their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. Proved oil and natural gas properties are evaluated by field for potential impairment. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of a field are less than its carrying value. If an impairment occurs, the carrying value of the impaired field is reduced to its estimated fair value, which is generally estimated using a discounted cash flow approach.

Unproved oil and natural gas properties do not have producing properties and are valued on acquisition by management, with the assistance of an independent expert when necessary. As reserves are proved through the successful completion of exploratory wells, the cost is transferred to proved properties. The cost of the remaining unproved basis is periodically evaluated by management to assess whether the value of a property has diminished. To do this assessment, management considers (i) estimated potential reserves and future net revenues from an independent expert, (ii) our history in exploring the area, (iii) our future drilling plans per our capital drilling program prepared by our reservoir engineers and operations management, and (iv) other factors associated with the area. Impairment is taken on the unproved property value if it is determined that the costs are not likely to be recoverable. The valuation is subjective and requires management to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual results.

Business Combinations. We follow ASC 805, *Business Combinations* ("ASC 805") and ASC 810-10-65, *Consolidation.* ASC 805 requires most identifiable assets, liabilities, non-controlling interests, and goodwill acquired in a business combination to be recorded at "fair value." The statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under ASC 805, all business combinations will be accounted for by applying the acquisition method.

Foreign Currency Translation and Remeasurement. We follow ASC 830, *Foreign Currency Matters* ("ASC 830") which requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. The functional currency for each of our subsidiaries in Turkey and Bulgaria is the local currency. For certain entities, translation adjustments result from the process of translating the functional currency of the foreign operation's financial statements into our U.S. Dollar reporting currency, which is a non-cash transaction. These translation adjustments are reported separately and accumulated in the consolidated balance sheets as a component of accumulated other comprehensive loss.

ASC 830 requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. Exchange gains or losses from re-measuring transactions and monetary accounts in a currency other than the functional currency are included in current earnings.

Oil and Gas Reserves. The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated financial statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board ("FASB"). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. We engaged DeGolyer and MacNaughton, our independent reserve engineers, to independently evaluate our Turkey and Bulgaria properties that result in estimates for all of our estimated proved reserves at December 31, 2018.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Income Taxes. We follow the asset and liability method prescribed by ASC 740, *Income Taxes* ("ASC 740"). Under this method of accounting for income taxes, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Under ASC 740, the effect on deferred tax assets and liabilities of a change in enacted tax rates is recognized in earnings in the period that includes the enactment date.

Other Recent Accounting Pronouncements and Reporting Rules

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 we 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 $4.7 million for the twelve months ended December 31, 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 twelve months ended December 31, 2017, this standard would have increased both revenue and expenses by $4.4 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.

The following table displays the disaggregation of revenue by product type for the twelve months ended December 31, 2018 and 2017:

	2018	2017
	(in thousands)	
Oil	$ 69,207	$ 58,109
Natural gas	1,061	1,807
Total revenue from customers	$ 70,268	$ 59,916

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 $12.9 million and $15.8 million as of December 31, 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 No. 2016-02, *Leases (Topic 842),* which establishes a new lease accounting model for leases. The most significant changes include the clarification of the definition of a lease, the requirement for lessees to recognize for all leases a right-of-use asset and a lease liability in the consolidated balance sheet, and additional quantitative and qualitative disclosures which are designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. Expenses are recognized in the consolidated statement of income in a manner similar to current accounting guidance. Lessor accounting under the new standard is substantially unchanged. The new standard will become effective for us beginning with the first quarter of 2019. We will adopt the accounting standard using a prospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows us to carry forward the historical accounting relating to lease identification and classification for existing leases upon adoption. We have made an accounting policy election to keep leases with an initial term of 12 months or less off of the consolidated balance sheet. We are finalizing our evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements and estimate approximately $2.7 million of additional right-of-use assets and liabilities will be recognized in our consolidated balance sheet upon adoption.

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 December 31, 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. The adoption of this ASU had no impact on our consolidated financial statements and results of operations. We adopted ASU 2017-09 effective January 1, 2018.

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.

Results of Operations—Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

	Year Ended December 31, 2018	Year Ended December 31, 2017	Change 2018-2017
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	1,020	1,104	(84)
Natural gas (Mmcf)	212	376	(164)
Total production (Mboe)	1,055	1,167	(112)
Average daily sales volumes (Boepd)	2,892	3,144	(252)
Average prices:			
Oil (per Bbl)	$ 67.84	$ 48.65	$ 19.19
Natural gas (per Mcf)	$ 5.01	$ 4.81	$ 0.20
Oil equivalent (per Boe)	$ 66.58	$ 47.58	$ 19.00
Revenues:			
Oil and natural gas sales	$ 70,268	$ 55,523	$ 14,745
Sales of purchased natural gas	-	654	(654)
Other	521	462	59
Total revenues	70,789	56,639	14,150
Costs and expenses:			
Production	10,769	12,249	(1,480)
Transportation costs	4,665	-	4,665
Exploration, abandonment and impairment	401	934	(533)
Cost of purchased natural gas	-	568	(568)
Seismic and other exploration	489	4,723	(4,234)
General and administrative	14,719	12,817	1,902
Depletion	13,387	15,989	(2,602)
Depreciation and amortization	672	936	(264)
Interest and other expense	10,048	8,838	1,210
Foreign exchange loss	10,292	1,861	8,431
Deferred income tax expense	6,854	3,356	3,498
(Loss) gain on commodity derivative contracts:			
Cash settlements on derivative contracts	(4,012)	32	(4,044)
Change in fair value on derivative contracts	1,186	(1,884)	3,070
Total loss on derivative contracts	(2,826)	(1,852)	(974)
Oil and natural gas costs per Boe:			
Production	$ 8.93	$ 9.16	$ (0.23)
Depletion	$ 11.10	$ 11.99	$ (0.89)

Oil and Natural Gas Sales. Total oil and natural gas sales increased to $70.3 million in 2018 compared to $55.5 million in 2017. The $14.7 million increase was primarily a result of an increase in our average realized price by $19.00 to $66.58 per Boe in 2018, compared to $47.58 per Boe in 2017, resulting in a $16.0 million increase in revenue. Additionally, revenues increased $4.7 million due to revenue reporting regulation ASC 606. This was partially offset by a decrease in sales volumes of 112 Mboe, which resulted in lower revenues of $5.9 million. Our sales of oil are denominated in U.S. Dollars and are not impacted by foreign exchange rates.

Sales of Purchased Natural Gas. Sales of purchased natural gas for the year ended December 31, 2018 decreased $0.7 million due to the divestiture of TBNG in February 2017.

Production. Production expenses for the year ended December 31, 2018 decreased to $10.8 million or $8.93 per Boe (WI), compared to $12.2 million or $9.16 per Boe (WI) for the year ended December 31, 2017. The $1.5 million decrease was primarily due to the devaluation of the TRY compared to the U.S. Dollar in 2018, as most of our production expenses are denominated in Turkish Lira, reduced headcount and cost-cutting measures in our field operations for the year ended December 31, 2018.

Transportation and Processing. Transportation and processing expense increased to $4.7 million for the twelve months ended December 31, 2018. The increase was due to the 2018 adoption of 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 decreased to $0.4 million in 2018, compared to $0.9 million for 2017. The decrease was primarily due to a decrease in impairment cost due to the increase in oil price.

Cost of Purchased Natural Gas. Cost of purchased natural gas for the year ended December 31, 2018 decreased $0.6 million to $0 due to the divestiture of TBNG in February 2017.

Seismic and Other Exploration. Seismic and other exploration costs decreased to $0.5 million for 2018, compared to $4.7 million for 2017. The decrease was primarily due to higher seismic acquisition activities during 2017, particularly on our Molla license.

General and Administrative. General and administrative expense increased $1.9 million to $14.7 million for 2018, compared to $12.8 million for 2017. The increase was primarily due to an increase in wages and strategic transaction costs in 2018. The increase in wages was primarily due to bonus pay and the accrual for strategic transaction retention incentive agreements entered into with certain employees in 2018.

Depletion. Depletion expense decreased to $13.4 million or $11.10 per Boe for 2018, compared to $16.0 million or $11.99 per Boe for 2017. The decrease was due primarily to a reduction in our sales volumes year-over-year and the devaluation of the TRY.

Interest and Other Expense. Interest and other expense increased to $10.0 million in 2018, compared to $8.8 million in 2017. The increase was primarily due to a higher average interest rate during 2018 as compared to 2017.

Foreign Exchange Loss. We recorded a foreign exchange loss of $10.3 million in 2018, compared to $1.9 million in 2017. The change in foreign exchange is 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 TRY amount if it has not been settled previously. Generally, a strengthening of the U.S.Dollar to the TRY increases our foreign exchange loss. The increase in foreign exchange loss in 2018 was due to a 39.5% devaluation of the TRY compared to the U.S. Dollar in 2018, compared to a 7.0% devaluation during 2017 and was partially offset by fluctuations in our U.S. Dollar denominated balances in Turkey. At December 31, 2018, the exchange rate was 5.2609 as compared to 3.7719 at December 31, 2017.

Deferred Income Tax Expense. Deferred income tax expense increased to an expense of $6.9 million for the year ended December 31, 2018, compared to a $3.4 million expense for 2017. The increase was primarily due to changes in our deferred tax liabilities related to our permanent reinvestment assertion in Turkey and increases in uncertain tax positions, which were partially offset by changes in temporary differences between our U.S. GAAP and statutory balances in Turkey.

Loss on Commodity Derivative Contracts. During 2018, we recorded a net loss on derivative contracts of $2.8 million, compared to $1.9 million for 2017. In 2018, we recorded a $4.0 million loss on settled contracts and a $1.2 million gain to mark our commodity derivative contracts to their fair value. In 2017, we recorded a $0.03 million loss on settled contracts and a $1.9 million loss to mark our commodity derivative contracts to their fair value.

Capital Expenditures

For 2018, we incurred $24.3 million in total capital expenditures, including license acquisition, seismic and corporate expenditures from operations, compared to $20.6 million for 2017.

We expect our net field capital expenditures for 2019 to range between $25.0 million and $30.0 million. We expect net field capital expenditures during 2019 to include between $24.0 million and $29.0 million in drilling and completion expense for 10 planned wells and approximately $1.0 million for recompletions. We expect that cash on hand and cash flow from operations will be sufficient to fund our 2019 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2019 capital expenditure budget is subject to change.

Liquidity and Capital Resources

Our primary sources of liquidity for 2018 were our cash and cash equivalents, cash flow from operations, borrowings under the 2017 Term Loan and our additional $10.0 million term loan with DenizBank. At December 31, 2018, we had cash and cash equivalents of $9.9 million, no long-term debt, $22.0 million in short-term debt and a working capital surplus of $2.5 million, compared to cash and cash equivalents of $18.9 million, $13.0 million in long-term debt, $15.6 million in short-term debt and a working capital surplus of $12.8 million.

During 2018, we repaid the 2016 Term Loan in full in accordance with its terms. In addition, we entered into the 2018 Term Loan under the Credit Agreement.

Based on current forecasted oil prices for 2019 and beyond, we believe that our cash flows from operations and existing cash on hand are sufficient to conduct our planned operations and meet our contractual requirements, including license obligations through March 31, 2020.

Net cash provided by operations during 2018 was $28.7 million, an increase from net cash provided by operations of $17.9 million in 2017, primarily due to an increase in revenue, partially offset by an increase in general and administrative expenses.

Net cash used investing activities during 2018 was $26.5 million, compared to net cash provided by investing activities of $1.9 million in 2017, primarily due to an $8.0 million increase in additions of oil and gas properties in 2018 and $17.8 million from sale proceeds of TBNG in 2017.

Net cash used in financing activities was $6.6 million in 2018, compared to net cash used in financing activities of $13.4 million in 2017. The decrease was primarily due to higher term loan repayments in 2017.

As of December 31, 2018, we had $22.0 million of debt and $46.1 million of Series A Preferred Shares outstanding, which are discussed below.

Series A Preferred Shares. On November 4, 2016, we issued 921,000 shares of our Series A Preferred Shares. Of the 921,000 Series A Preferred Shares, (i) 815,000 shares were issued in exchange for $40.75 million aggregate principal amount of our 13.0% Senior Convertible Notes due 2017 (the "2017 Notes"), at an exchange rate of 20 Series A Preferred Shares for each $1,000 principal amount of 2017 Notes, and (ii) 106,000 shares were issued and sold to certain holders of the 2017 Notes. All of the Series A Preferred Shares were issued at a value of $50.00 per share, raising gross proceeds of $5.3 million. We used $4.3 million of the gross proceeds to redeem a portion of the remaining 2017 Notes. The remaining proceeds were used for general corporate purposes. 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 sheet.

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 adjustment 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 date 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 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 are also entitled to participate pro-rata in any dividends paid on the common shares on an as-converted-to-common shares basis. For the year ended December 31, 2018, we paid $5.3 million in cash and issued 1,808,001 common shares as dividends on the Series A Preferred Shares. We paid the December 31, 2018 quarterly dividend in shares on December 31, 2018.

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 its most recent independent reserve report filed or furnished on EDGAR.

2016 Term Loan. 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 Mr. Mitchell and 20% 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 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.

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 had a grace period which bore no interest or payments due until July 2018. Thereafter, the 2017 Term Loan 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 Mr. Mitchell and 20% Mr. 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.

At December 31, 2018, we had $13.0 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.

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 had a grace period through July 2018 during which no payments were 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 Mr. Mitchell and 20% Mr. 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.

At December 31, 2018, we had $9.0 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 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% per annum.

Interest was payable semi-annually, in arrears, on January 1 and July 1 of each year. The 2017 Notes matured on July 1, 2017, and we paid off and retired all remaining outstanding 2017 Notes on July 3, 2017.

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements at December 31, 2018.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Not applicable.

Item 8. Financial Statements and Supplementary Data

See Index to Financial Statements on page F-1.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are designed to ensure that information required to be disclosed in reports filed or submitted under 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 our chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 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. Based upon the evaluation, our chief executive officer and principal accounting and financial officer concluded that, as of December 31, 2018, our disclosure controls and procedures were effective.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act, is a process designed by, or under the supervision of, the chief executive officer and principal accounting and financial officer, or persons performing similar functions, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP and includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, (iii) provide reasonable assurance that receipts and expenditures are being made only in accordance with appropriate authorizations of management and the board of directors, and (iv) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Our management, under the supervision and with the participation of our chief executive officer and principal accounting and financial officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Certain information required in response to this Item 10 is contained under the heading "Executive Officers of the Registrant" in Part I of this Annual Report on Form 10-K. Other information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act, not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Code of Business Conduct

We have adopted a code of ethics that applies to all our officers, directors and employees, including our principal executive officer, principal financial officer, principal accounting officer and controller. The full text of our Code of Conduct is published on our website at *www.transatlanticpetroleum.com*, on the Corporate Governance page under the About tab. We intend to disclose future amendments to certain provisions of the Code of Conduct, or waivers of such provisions granted to executive officers and directors, on our website within four business days following the date of such amendment or waiver.

Item 11. Executive Compensation

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14. Principal Accountant Fees and Services

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of the Report.

1. Reports of Independent Registered Public Accounting Firm (RBSM 2018)
   Reports of Independent Registered Public Accounting Firm (PMB 2017)
   Consolidated Balance Sheets as of December 31, 2018 and 2017
   Consolidated Statements of Operation and Comprehensive Loss for the years ended December 31, 2018 and 2017
   Consolidated Statements of Equity for the years ended December 31, 2018 and 2017
   Consolidated Statements of Cash Flows for the years ended December 31, 2018 and 2017
   Notes to Consolidated Financial Statements
2. Exhibits required to be filed by Item 601 of Regulation S-K

The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this report.

EXHIBIT INDEX

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).
3.5*	Memorandum of Increase of Share Capital of TransAtlantic Petroleum Ltd., dated July 2017.
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	Service Agreement, effective as of May 1, 2008, by and among TransAtlantic Petroleum Corp., Longfellow Energy, LP, Viking Drilling, LLC, Longe Energy Limited and Riata Management, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 6, 2008, filed with the SEC on February 12, 2009).
10.2	Amendment to Service Agreement, effective as of October 1, 2008, by and among TransAtlantic Petroleum Corp., Longfellow Energy, LP, Viking Drilling, LLC, Longe Energy Limited, MedOil Supply LLC and Riata Management, LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated August 6, 2008, filed with the SEC on February 12, 2009).
10.3	Domestic Crude Oil Purchase/Sale Agreement, dated as of January 26, 2009, by and between Türkiye Petrol Rafinerileri A.Ş. and TransAtlantic Exploration Mediterranean International Pty. Ltd. (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
10.4†	TransAtlantic Petroleum Corp. 2009 Long-Term Incentive Plan (incorporated by reference to Appendix B to the Definitive Proxy Statement filed by TransAtlantic Petroleum Corp. with the SEC on April 30, 2009).
10.5†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated June 16, 2009, filed with the SEC on June 22, 2009).
10.6†	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated July 13, 2011, filed with the SEC on July 19, 2011).
10.7	Master Services Agreement, dated March 3, 2016, by and between TransAtlantic Exploration Mediterranean International Pty Ltd and Production Solutions International Petrol Arama Hizmetleri Anonim Sirketi (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated February 29, 2016, filed with the SEC on March 4, 2016).
10.8	Form of General Credit Agreement, dated August 23, 2016, by and among DenizBank A.S., TransAtlantic Exploration Mediterranean International Pty Ltd, TransAtlantic Turkey, Ltd., DMLP, Ltd. and Talon Exploration, Ltd (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 10-Q dated September 30, 2016, filed with the SEC on November 9, 2016).
10.9	Note Amendment Agreement, dated April 19, 2016, by and among TransAtlantic Petroleum Ltd., Dalea Partners, LP., and N. Malone Mitchell 3rd (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated April 19, 2016, filed with the SEC on April 22, 2016).
10.10	Amended and Restated Promissory Note, dated April 19, 2016, by and between TransAtlantic Petroleum Ltd. and Dalea Partners, LP (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated April 19, 2016, filed with the SEC on April 22, 2016).

10.11 Pledge Agreement, dated April 19, 2016, by and between TransAtlantic Petroleum Ltd. and Dalea Partners, LP (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K dated April 19, 2016, filed with the SEC on April 22, 2016).

10.12 Indemnity Agreement, dated May 9, 2016, by and between TransAtlantic Petroleum Ltd. and Mr. Mitchell (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 10-Q dated March 31, 2016, filed with the SEC on May 10, 2016).

10.13 Gundem Pledge Fee Agreement, dated August 31, 2016, by and between Gundem Turizm Yatirim Ve Isletmeleri A.S. and TransAtlantic Petroleum Ltd. (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K, filed with the SEC on March 22, 2017).

10.14 Diyarbakir Pledge Fee Agreement, dated August 31, 2016, by and among Mr. Mitchell, Mr. Uras and TransAtlantic Petroleum Ltd. (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K, filed with the SEC on March 22, 2017).

10.15 Second Amendment to Service Agreement, dated March 20, 2017, by and among TransAltantic Petroleum Ltd. and Longfellow Energy, LP, Riata Management, LLC, Longfellow Nemaha, LLC, Red Rock Minerals, LP, Red Rock Advisors, LLC, Production Solutions International Limited and Nexlube Operating, LLC (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K, filed with the SEC on March 22, 2017).

10.16 Current Account Loan Contract, dated November 28, 2017, by and between TransAtlantic Exploration Mediterranean International Pty Ltd and DenizBank A.S. (incorporated by reference to Exhibit 10.18 to the Company's Annual Report on Form 10-K dated December 31, 2017, filed with the SEC on March 21, 2018).

10.17 Form of 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).

10.18 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).

10.19 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).

10.20 Term Loan Contract, dated February 22, 2019, 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 February 22, 2019, filed with the SEC on February 28, 2019).

10.21 Amendment No. 1 to the Amended and Restated Promissory Note, dated February 28, 2019, by and between the Company and Dalea Partners, LP (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K dated February 22, 2019, filed with the SEC on February 28, 2019).

10.22 Amendment No. 1 to the Master Services Agreement, dated February 28, 2019, by and between TransAtlantic Exploration Mediterranean International Pty Ltd and Production Solutions International Petrol Arama Hizmetleri Anomin Sirketi (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K dated February 22, 2019, filed with the SEC on February 28, 2019).

21.1* Subsidiaries of the Company.

23.1* Consent of RBSM LLP.

23.2* Consent of PMB Helin Donovan, LLP.

23.3* Consent of DeGolyer and MacNaughton.

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 of the Company, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Principal Accounting and Financial Officer of the Company, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of DeGolyer and MacNaughton, dated February 13, 2019.
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.

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† Management contract or compensatory plan arrangement.
* Filed herewith.
** Furnished herewith.

SIGNATURES

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

March 26, 2019

TRANSATLANTIC PETROLEUM LTD.

/s/ N. MALONE MITCHELL 3rd
N. Malone Mitchell 3rd
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/S/ N. MALONE MITCHELL 3rd **N. Malone Mitchell 3rd**	Chairman and Chief Executive Officer (Principal Executive Officer)	March 26, 2019
/S/ MICHAEL P. HILL **Michael P. Hill**	Chief Accounting Officer (Principal Financial Officer and Principal Accounting Officer)	March 26, 2019
/S/ BOB G. ALEXANDER **Bob G. Alexander**	Director	March 26, 2019
/S/ BRIAN E. BAYLEY **Brian Bayley**	Director	March 26, 2019
/S/ CHARLES J. CAMPISE **Charles J. Campise**	Director	March 26, 2019
/S/ JONATHON T. FITE **Jonathon T. Fite**	Director	March 26, 2019
/S/ GREGORY K. RENWICK **Gregory K. Renwick**	Director	March 26, 2019
/S/ MEL G. RIGGS **Mel G. Riggs**	Director	March 26, 2019
/S/ RANDY I. ROCHMAN **Randy I. Rochman**	Director	March 26, 2019

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Transatlantic Petroleum Ltd.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheet of Transatlantic Petroleum Ltd. and subsidiaries (the "Company") as of December 31, 2018 and the related consolidated statements of operations and comprehensive loss, stockholders' equity, and cash flows for the year then ended, and the related notes and schedules (collectively, the consolidated financial statements).

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and comprehensive loss and its cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

Emphasis of a Matter

As discussed in Notes 1 and 16 to the consolidated financial statements, there are a number of significant related party transactions with the primary shareholder of the Company. This shareholder is the Company's chief executive officer and chairman of the board of directors. Significant related party transactions with this shareholder include ownership of Series A Preferred Shares, equity transactions, a note receivable, pledge fee agreements and service transactions.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit, we are required to obtain an understanding of internal control over financial reporting, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion

Our audit of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provide a reasonable basis for our opinion.

/s/ RBSM LLP

We have served as the Company's auditor since 2018.

New York, NY
March 26, 2019

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
TransAtlantic Petroleum Ltd.:

Opinion on the Financial Statements

We have audited, before the effects of the adjustments to retrospectively apply the application of presenting restricted cash in the statement of cash flows as described in note 4, the accompanying consolidated balance sheet of TransAtlantic Petroleum Ltd. (a Bermuda corporation) and subsidiaries (the "Company") as of December 31, 2017, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for the year ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). The 2017 financial statements before the effects of the adjustments on restricted cash in the Statement of Cash Flows are not presented herein. In our opinion, the financial statements, before the effects of the adjustments to retrospectively apply the application of restricted cash described in note 4, referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017, and the results of its operations, changes in equity, and cash flows for the year ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness if the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risk of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively apply the application of presenting restricted cash in the statement of cash flows as described in note 4 and, accordingly, we do not express an opinion or any other form of assurance about whether such adjustments are appropriate and have been properly applied. Those adjustments were audited by a successor auditor.

Emphasis of a Matter

As discussed in Notes 1 and 16 to the financial statements, there are a number of significant related party transactions with the primary shareholder of the Company. This shareholder, who is the Company's chief executive officer and chairman of the board of directors, owns approximately 47% of the common stock of the Company. Significant related party transactions with this shareholder include ownership of Series A Preferred Shares, equity transactions, a note receivable, pledge fee agreements, service transactions, a note payable balance and warrants between the Company and affiliated entities or persons.

We have served as the Company's Auditors since 2016.

PMB HELIN DONOVAN, LLP
/s/ PMB Helin Donovan, LLP

Austin, Texas
March 21, 2018

TRANSATLANTIC PETROLEUM LTD.

Consolidated Balance Sheets
As of December 31, 2018 and 2017
(in thousands of U.S. Dollars, except share data)

	2018	2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,892	$ 18,926
Accounts receivable, net		
Oil and natural gas sales	12,912	15,808
Joint interest and other	982	1,576
Related party	878	1,023
Prepaid and other current assets	8,696	3,866
Note receivable - related party	5,828	–
Inventory	5,167	7,494
Total current assets	44,355	48,693
Property and equipment:		
Oil and natural gas properties (successful efforts method)		
Proved	163,006	193,647
Unproved	15,695	24,445
Equipment and other property	14,408	14,075
	193,109	232,167
Less accumulated depreciation, depletion and amortization	(105,850)	(129,183)
Property and equipment, net	87,259	102,984
Other long-term assets:		
Other assets	986	2,247
Note receivable - related party	–	6,726
Total other assets	986	8,973
Total assets	$ 132,600	$ 160,650
LIABILITIES, SERIES A PREFERRED SHARES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 3,896	$ 4,853
Accounts payable - related party	2,922	3,141
Accrued liabilities	13,073	10,014
Derivative liability	–	2,215
Loans payable	22,000	15,625
Total current liabilities	41,891	35,848
Long-term liabilities:		
Asset retirement obligations	4,667	4,727
Accrued liabilities	7,259	8,810
Deferred income taxes	20,314	19,611
Loans payable	–	13,000
Total long-term liabilities	32,240	46,148
Total liabilities	74,131	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 December 31, 2018	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 December 31, 2018	24,750	24,750
Shareholders' equity:		
Common shares, $0.10 par value, 200,000,000 shares authorized; 52,413,588 shares and 50,319,156 shares issued and outstanding as of December 31, 2018 and 2017, respectively	5,241	5,032
Treasury shares	(970)	(970)
Additional paid-in-capital	577,488	575,411
Accumulated other comprehensive loss	(142,021)	(124,766)
Accumulated deficit	(427,319)	(422,103)
Total shareholders' equity	12,419	32,604
Total liabilities, Series A preferred shares and shareholders' equity	$ 132,600	$ 160,650

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

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Operation and Comprehensive Loss
For the Years ended December 31, 2018 and 2017
(U.S. Dollars and shares in thousands, except per share amounts)

	2018	2017
Revenues:		
Oil and natural gas sales	$ 70,268	$ 55,523
Sales of purchased natural gas	–	654
Other	521	462
Total revenues	70,789	56,639
Costs and expenses:		
Production	10,769	12,249
Transportation costs	4,665	–
Exploration, abandonment and impairment	401	934
Cost of purchased natural gas	–	568
Seismic and other exploration	489	4,723
General and administrative	14,719	12,817
Depreciation, depletion and amortization	14,059	16,925
Accretion of asset retirement obligations	174	190
Total costs and expenses	45,276	48,406
Operating income	25,513	8,233
Other (expense) income:		
Loss on sale of TBNG	–	(15,226)
Interest and other expense	(10,048)	(8,838)
Interest and other income	1,082	1,098
Loss on commodity derivative contracts	(1,797)	(1,852)
Foreign exchange loss	(10,292)	(1,861)
Total other expense	(21,055)	(26,679)
Income (loss) before income taxes	4,458	(18,446)
Current income tax expense	(2,820)	(2,073)
Deferred income tax expense	(6,854)	(3,356)
Net loss	(5,216)	(23,875)
Other comprehensive loss:		
Foreign currency translation adjustment	(17,255)	15,550
Comprehensive loss	$ (22,471)	$ (8,325)
Net loss per common share:		
Basic net loss per common share	$ (0.10)	$ (0.50)
Weighted average common shares outstanding	50,505	48,196
Diluted net loss per common share	$ (0.10)	$ (0.50)
Weighted average common and common equivalent shares outstanding	50,505	48,196

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

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Equity
For the Years ended December 31, 2018 and 2017
(U.S. Dollars and shares in thousands)

	Common Shares	Treasury Shares	Warrants	Common Shares (at par)	Treasury Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Shareholders' Equity
Balances at December 31, 2016	47,220	333	699	$ 4,722	$ (970)	$ 573,278	$ (140,316)	$ (398,228)	$ 38,486
Issuance of common shares	2,591	–	–	259	–	1,584	–	–	1,842
Issuance of restricted stock units	507	–	–	51	–	(51)	–	–	-
Tax withholding on restricted stock units	–	–	–	–	–	(92)	–	–	(92)
Share-based compensation	–	–	–	–	–	693	–	–	693
Foreign currency translation adjustment	–	–	–	–	–	–	15,550	–	15,550
Net loss	–	–	–	–	–	–	–	(23,875)	(23,875)
Balances at December 31, 2017	50,319	333	699	5,032	(970)	575,412	(124,766)	(422,103)	32,604
Issuance of common shares	1,808	–	–	181	–	1,660	–	–	1,842
Issuance of restricted stock units	286	–	–	28	–	(28)	–	–	-
Expiration of warrants	–		(699)	–	–	–	–	–	-
Tax effect of restricted stock units	–	–	–	–	–	(11)	–	–	(11)
Share-based compensation	–	–	–	–	–	455	–	–	455
Foreign currency translation adjustment	–	–	–	–	–	–	(17,255)	–	(17,255)
Net loss	–	–	–	–	–	–	–	(5,216)	(5,216)
Balances at December 31, 2018	52,413	333	–	$ 5,241	$ (970)	$ 577,488	$ (142,021)	$ (427,319)	$ 12,419

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

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Cash Flows
For the Years ended December 31, 2018 and 2017
(in thousands of U.S. Dollars)

	2018	2017
Operating activities:		
Net loss	$ (5,216)	$ (23,875)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Share-based compensation	455	693
Foreign currency (income) loss	13,299	(440)
Loss on commodity derivative contracts	1,797	1,852
Cash settlement on commodity derivative contracts	(4,012)	32
Amortization on loan financing costs	42	82
Interest on Series A Preferred Shares paid in common shares	1,842	1,842
Deferred income tax expense	6,854	3,356
Exploration, abandonment and impairment	401	934
Depreciation, depletion and amortization	14,059	16,925
Accretion of asset retirement obligations	174	190
Loss on Sale of TBNG	–	15,226
Changes in operating assets and liabilities:		
Accounts receivable	(1,358)	2,255
Prepaid expenses and other assets	(6,673)	(859)
Accounts payable and accrued liabilities	7,031	(333)
Net cash provided by operating activities	28,695	17,880
Investing activities:		
Additions to oil and natural gas properties	(23,517)	(15,478)
Additions to equipment and other properties	(3,015)	(366)
Proceeds from asset sale	–	17,779
Net cash provided by (used in) investing activities	(26,532)	1,935
Financing activities:		
Tax withholding on restricted share units	(11)	(92)
Loan proceeds	10,000	20,375
Loan repayment	(16,625)	(30,475)
Loan repayment - related party	–	(3,219)
Net cash used in financing activities	(6,636)	(13,411)
Effect of exchange rate on cash flows, cash equivalents and restricted cash	(5,931)	(1,044)
Net increase (decrease) in cash, cash equivalents and restricted cash	(10,404)	5,360
Cash, cash equivalents and restricted cash, beginning of year (1)	20,431	15,071
Cash, cash equivalents and restricted cash, end of year (2)	$ 10,027	$ 20,431
Supplemental disclosures:		
Cash paid for interest	$ 7,917	$ 5,620
Cash paid for taxes	$ 3,239	$ 2,151

(1) The balance at January 1, 2017 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 balance at January 1, 2018 includes cash and cash equivalents of $18.9 million and restricted cash of $1.5 million in other assets.

(2) The end 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. The end of period balance at December 31, 2018 includes cash and cash equivalents of $9.9 million and restricted cash of $0.1 million in other assets.

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

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, have stable governments, 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 March 22, 2019, approximately 48% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, our chief executive officer and chairman of our board of directors.

TransAtlantic is a holding company with two operating segments – Turkey and Bulgaria. Its assets consist of its 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 these notes to the consolidated financial statements are in U.S. Dollars unless otherwise indicated. 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, stock based compensation and financial derivatives, collectability of accounts receivable, 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.

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 net cash proceeds of $16.1 million, which reflect a $0.2 million post-closing purchase price adjustment. Although the sale of TBNG met the threshold to classify its assets and liabilities as held for sale, it did not meet the requirements to classify its operations as discontinued, as the sale was not 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 17 "Divestitures and discontinued operations").

2. Liquidity

During 2018, we repaid the 2016 Term Loan in full in accordance with its terms and entered into the 2018 Term Loan with DenizBank, A.S. ("DenizBank") for $10.0 million. (see Note 9 "Loans Payable").

As of December 31, 2018, we had no long-term debt, $22.0 million in short-term debt, $9.9 million in cash and a $2.5 million working capital surplus.

Based on current forecasted oil prices for 2019 and beyond, we believe that our cash flows from operations and existing cash on hand are sufficient to conduct our planned operations and meet our contractual requirements, including license obligations through March 31, 2020.

3. Significant accounting policies

Basis of preparation

Our reporting standard for the presentation of our consolidated financial statements is U.S. GAAP. The consolidated financial statements include the accounts of the Company and all majority-owned, controlled subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Accounts receivable, net

We have receivables for sales of oil and natural gas, as well as receivables related to joint interest accounts, which have a contractual maturity of one year or less. An allowance for doubtful accounts has been established based on management's review of the collectability of the receivables in light of historical experience, the nature and volume of the receivables and other subjective factors. Accounts receivable are charged against the allowance, upon approval by management, when they are deemed uncollectible. Our allowance for doubtful accounts was $0.5 million at December 31, 2018 and 2017.

Cash and cash equivalents

Cash and cash equivalents include term deposits and investments with original maturities of three months or less at the date of acquisition. We consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. We determine the appropriate classification of our investments in cash and cash equivalents and marketable securities at the time of purchase and reevaluate such designation at each balance sheet date.

Derivative instruments

Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 815, *Derivatives and Hedging* ("ASC 815"), requires derivative instruments to be recognized as either assets or liabilities in the balance sheet at fair value. We do not designate our derivative financial instruments as hedging instruments and, as a result, we recognize the change in a derivative contract's fair value currently in earnings as a component of other income (expense).

Fair value measurements

We follow ASC 820, *Fair Value Measurements and Disclosures* ("ASC 820"). This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC 820 does not require any new fair value measurements, but applies to assets and liabilities that are required to be recorded at fair value under other accounting standards.

ASC 820 characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair value measurement hierarchy are as follows:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3: Measured based on prices or valuation models that required inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

As required by ASC 820, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values takes into account the market for our financial assets and liabilities, the associated credit risk and other factors as required by ASC 820. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Foreign currency remeasurement and translation

The functional currency of our subsidiaries in Turkey and Bulgaria is the New Turkish Lira ("TRY") and the Bulgarian Lev, respectively. We follow ASC 830, *Foreign Currency Matters* ("ASC 830"). ASC 830 requires the assets, liabilities, and results of operations of a foreign operation to be measured using the functional currency of that foreign operation. Exchange gains or losses from remeasuring transactions and monetary accounts in a currency other than the functional currency are included in current earnings.

For certain subsidiaries, translation adjustments result from the process of translating the functional currency of subsidiary financial statements into the U.S. Dollar reporting currency. These translation adjustments are reported separately and accumulated in the consolidated balance sheets as a component of accumulated other comprehensive loss.

Oil and natural gas properties

In accordance with the successful efforts method of accounting for oil and natural gas properties, costs of productive wells, developmental dry holes and productive leases are capitalized into appropriate groups of properties based on geographical and geological similarities. Acquisition costs of proved properties are amortized using the unit-of-production method based on total proved reserves, and exploration well costs and additional development costs are amortized using the unit-of-production method based on proved developed reserves. Proceeds from the sale of properties are credited to property costs, and a gain or loss is recognized when a significant portion of an amortization base is sold or abandoned.

Exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged to expense as incurred. Exploratory drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to exploration expense if and when the well is determined to be non-productive. The determination of an exploratory well's ability to produce must be made within one year from the completion of drilling activities. The acquisition costs of unproved acreage are initially capitalized and are carried at cost, net of accumulated impairment provisions, until such leases are transferred to proved properties or charged to exploration expense as impairments of unproved properties.

Equipment and other property

Equipment and other property are stated at cost, and inventory is stated at weighted average cost which does not exceed replacement cost. Depreciation is calculated using the straight-line method over the estimated useful lives (ranging from 3 to 7 years) of the respective assets. The costs of normal maintenance and repairs are charged to expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of equipment sold, or otherwise disposed of, and the related accumulated depreciation, are removed from the accounts and any gain or loss is reflected in current earnings.

Impairment of long-lived assets

We follow the provisions of ASC 360, *Property, Plant, and Equipment* ("ASC 360"). ASC 360 requires that our long-lived assets be assessed for potential impairment of their carrying values whenever events or changes in circumstances indicate such impairment may have occurred. Proved oil and natural gas properties are evaluated by field for potential impairment. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of a field are less than its carrying value. If an impairment occurs, the carrying value of the impaired field is reduced to its estimated fair value, which is generally estimated using a discounted cash flow approach.

Unproved oil and natural gas properties do not have producing properties and are valued on acquisition by management, with the assistance of an independent expert when necessary. As reserves are proved through the successful completion of exploratory wells, the cost is transferred to proved properties. The cost of the remaining unproved basis is periodically evaluated by management to assess whether the value of a property has diminished. To do this assessment, management considers (i) estimated potential reserves and future net revenues from an independent expert, (ii) our history in exploring the area, (iii) our future drilling plans per our capital drilling program prepared by our reservoir engineers and operations management and (iv) other factors associated with the area. Impairment is taken on the unproved property value if it is determined that the costs are not likely to be recoverable. The valuation is subjective and requires management to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual results.

Joint interest activities

Certain of our exploration, development and production activities are conducted jointly with other entities and, accordingly, the consolidated financial statements reflect only our proportionate interest in such activities.

Asset retirement obligations

We recognize a liability for the fair value of all legal obligations associated with the retirement of tangible, long-lived assets and capitalize an equal amount as a cost of the asset. The cost associated with the abandonment obligation is included in the computation of depreciation, depletion and amortization. The liability accretes until we settle the obligation. We use a credit-adjusted risk-free interest rate in our calculation of asset retirement obligations.

Revenue recognition

As explained below (see Note 4 "New accounting pronouncements"), on January 1, 2018, we adopted FASB Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers* (Topic 606) ("ASU 2014-09"), 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. The timing of revenue recognition for our various revenue streams was not materially impacted by the adoption of this standard. The Company believes its business processes, systems, and controls are appropriate to support recognition and disclosure ASU 2014-09. We do not expect any impact to our net income from the adoption of ASU 2014-09 on an ongoing basis.

The Company recognizes revenue in accordance with FASB, ASC 606, *Revenue from Contracts with Customers* (“ASC 606”). Revenues are recognized when control is transferred to customers in amounts that reflect the consideration the Company expects to be entitled to receive in exchange for those goods. Revenue recognition is evaluated through the following five steps: (i) identification of the contract, or contracts, with a customer; (ii) identification of the performance obligations in the contract; (iii) determination of the transaction price; (iv) allocation of the transaction price to the performance obligations in the contract; and (v) recognition of revenue when or as a performance obligation is satisfied.

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.

During the years ended December 31, 2018 and 2017, we sold \$68.2 million and \$54.9 million, respectively, of oil to Türkiye Petrol Rafinerileri A.Ş. (“TUPRAS”), a privately-owned oil refinery in Turkey, which represented approximately 96.4%, and 97.0% of our total revenues, respectively.

Share-based compensation

We follow ASC 718, *Compensation—Stock Compensation* (“ASC 718”), which requires the measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, based on estimated grant date fair values. Restricted stock units are valued using the market price of our common shares on the date of grant. We record compensation expense, net of estimated forfeitures, over the requisite service period.

Series A Preferred Shares

On November 4, 2016, we issued 921,000 shares of 12.0% Series A Convertible Redeemable Preferred Shares (the “Series A Preferred Shares”). Of the 921,000 Series A Preferred Shares, (i) 815,000 shares were issued in exchange for \$40.75 million of our 13.0% Senior Convertible Notes due 2017 (the “2017 Notes”), at an exchange rate of 20 Series A Preferred Shares for each \$1,000 principal amount of 2017 Notes, and (ii) 106,000 shares were issued and sold for \$5.3 million of cash to certain holders of the 2017 Notes. All of the Series A Preferred Shares were issued at a value of \$50.00 per share (see Note 5 “Series A Preferred Shares”). As the shares can be redeemed, they have been classified outside of equity.

Income taxes

We follow the asset and liability method prescribed by ASC 740, *Income Taxes* (“ASC 740”). Under this method of accounting for income taxes, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Under ASC 740, the effect on deferred tax assets and liabilities of a change in enacted tax rates is recognized in earnings in the period that includes the enactment date.

As of December 31, 2018 and 2017, we have recorded a \$6.7 million and \$8.7 million liability, respectively, primarily due to uncertain tax positions related to the unwinding of all of our crude oil hedge collars and three-way contracts, which are included in long-term accrued liabilities on our consolidated balance sheet.

We do not believe there will be any material changes in our unrecognized tax positions over the next twelve months. Our policy is that we recognize interest and penalties accrued on any unrecognized tax positions as a component of income tax expense.

We are a Bermuda exempted company, and under current Bermuda law, we are not subject to tax on profits, income or dividends, nor is there any capital gains tax applicable to us in Bermuda.

Comprehensive income

We follow ASC 220, *Comprehensive Income*, which establishes standards for reporting and displaying comprehensive income and its components (revenue, expenses, gains and losses) in a full set of general-purpose financial statements.

Business combinations

We follow ASC 805, *Business Combinations* ("ASC 805") and ASC 810-10-65, *Consolidation*. ASC 805 requires most identifiable assets, liabilities, non-controlling interests, and goodwill acquired in a business combination to be recorded at "fair value." The statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under ASC 805, all business combinations are accounted for by applying the acquisition method.

Per share information

Basic per share amounts are calculated using the weighted average common shares outstanding during the year, excluding unvested restricted stock units. We use the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations in computing diluted earnings per share. Diluted calculations reflect the weighted average incremental common shares that would be issued upon exercise of dilutive options assuming the proceeds would be used to repurchase shares at average market prices for the period.

4. New 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 $4.7 million for the twelve months ended December 31, 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 twelve months ended December 31, 2017, this standard would have increased both revenue and expenses by $4.4 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.

The following table displays the disaggregation of revenue by product type for the twelve months ended December 31, 2018 and 2017:

	2018	2017
	(in thousands)	
Oil	$ 69,207	$ 58,109
Natural gas	1,061	1,807
Total revenue from customers	$ 70,268	$ 59,916

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 $12.9 million and $15.8 million as of December 31, 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 No. 2016-02, *Leases (Topic 842),* which establishes a new lease accounting model for leases. The most significant changes include the clarification of the definition of a lease, the requirement for lessees to recognize for all leases a right-of-use asset and a lease liability in the consolidated balance sheet, and additional quantitative and qualitative disclosures which are designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. Expenses are recognized in the consolidated statement of income in a manner similar to current accounting guidance. Lessor accounting under the new standard is substantially unchanged. The new standard will become effective for us beginning with the first quarter of 2019. We will adopt the accounting standard using a prospective transition approach, which applies the provisions of the new guidance at the effective date without adjusting the comparative periods presented. We have elected the package of practical expedients permitted under the transition guidance within the new standard, which among other things, allows us to carry forward the historical accounting relating to lease identification and classification for existing leases upon adoption. We have made an accounting policy election to keep leases with an initial term of 12 months or less off of the consolidated balance sheet. We are finalizing our evaluation of the impacts that the adoption of this accounting guidance will have on the consolidated financial statements and estimate approximately $2.7 million of additional right-of-use assets and liabilities will be recognized in our consolidated balance sheet upon adoption.

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 December 31, 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. The adoption of this ASU had no impact on our consolidated financial statements and results of operations. We adopted ASU 2017-09 effective January 1, 2018.

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 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.

5. Series A Preferred Shares

Series A Preferred Shares

On November 4, 2016, we issued 921,000 Series A Preferred Shares. Of the 921,000 Series A Preferred Shares, (i) 815,000 shares were issued in exchange for $40.75 million of the 2017 Notes, at an exchange rate of 20 Series A Preferred Shares for each $1,000 principal amount of 2017 Notes, and (ii) 106,000 shares were issued and sold for $5.3 million of cash to certain holders of the 2017 Notes. All of the Series A Preferred Shares were issued at a value of $50.00 per share. We used $4.3 million of the gross proceeds to redeem a portion of the remaining 2017 Notes on January 1, 2017. The remaining proceeds were used for general corporate purposes. 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 sheet. As of December 31, 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 16 "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 of the Company (which is equal to an initial conversion price of approximately $1.0928 per common share and is subject to customary adjustment 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 date 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 June 30, September 30, December 31, and March 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. As of December 31, 2018 and 2017, we paid $5.3 million and accrued $6.0 million, respectively, in dividends on the Series A Preferred Shares, which is recorded in our consolidated statements of comprehensive loss under the caption “Interest and other expense”. These amounts were paid in cash and common shares.

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.

6. Property and equipment

Oil and natural gas properties

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

	2018	2017
	(in thousands)	
Oil and natural gas properties, proved:		
Turkey	$ 162,494	$ 193,111
Bulgaria	512	536
Total oil and natural gas properties, proved	163,006	193,647
Oil and natural gas properties, unproved:		
Turkey	14,965	24,445
Bulgaria	730	-
Total oil and natural gas properties, unproved	15,695	24,445
Gross oil and natural gas properties	178,701	218,092
Accumulated depletion	(100,582)	(123,225)
Net oil and natural gas properties	$ 78,119	$ 94,867

The decline in oil and natural gas properties during the year ended December 31, 2018 was primarily driven by the devaluation of the Turkish Lira (“TRY”) versus the U.S. Dollar. For the year ended December 31, 2018 and 2017, we have recorded foreign currency translation adjustments which reduced oil and natural gas properties and increased accumulated other comprehensive loss within shareholders’ equity on our consolidated balance sheet.

At December 31, 2018 and 2017, we excluded $0.5 million of costs from the depletion calculation for development wells in progress.

At December 31, 2018, the capitalized costs of our oil and natural gas properties included $6.5 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and $53.4 million relating to well costs and additional development costs, which are being amortized 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. The factors used to determine fair value include (Level 3 inputs), but are 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 year ended December 31, 2018, we recorded $0.3 million of impairment of proved properties and exploratory well costs which are primarily measured using Level 3 inputs primarily relating to two of our gas fields.

During the year ended December 31, 2017, we recorded $0.8 million of impairment of proved properties and exploratory well costs which are primarily measured using Level 3 inputs primarily relating to two of our gas fields.

Capitalized costs greater than one year

As of December 31, 2018, there were no capitalized exploratory well costs greater than one year.

As of December 31, 2017, we had $4.0 million of exploratory well costs capitalized for the Pinar-1 well in Turkey. During the first quarter of 2018, the well began producing.

Equipment and other property

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

	2018	2017
	(in thousands)	
Other equipment	$ 1,240	$ 1,764
Land	149	–
Inventory	6,791	4,619
Gas gathering system and facilities	194	135
Vehicles	336	343
Leasehold improvements, office equipment and software	5,698	7,214
Gross equipment and other property	14,408	14,075
Accumulated depreciation	(5,268)	(5,958)
Net equipment and other property	$ 9,140	$ 8,118

At December 31, 2018 and 2017, we classified $5.2 million and $7.5 million of inventory, respectively, as a current asset, which represents our expected inventory consumption during the next twelve months. We classify the remainder of 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 December 31, 2018 and 2017, we excluded $12.0 million and $12.1 million of inventory, respectively, from depreciation, as the inventory had not been placed into service.

7. 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 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 December 31, 2018, we had no outstanding commodity derivative contracts with respect to our future crude oil production.

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

Fair Value of Derivative Instruments as of December 31, 2017

Type	Period	Quantity (Bbl/day)	Collars Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	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)

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 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 December 31, 2018 and 2017, we had no outstanding derivative contracts with respect to our foreign exchange rates.

During the years ended December 31, 2018 and 2017, we recorded a net loss on derivative contracts of $1.8 million and $1.9 million, respectively.

Balance sheet presentation

The following table summarizes both: (i) the gross fair value of our commodity derivative instruments by the appropriate balance sheet classification even when the commodity derivative instruments are subject to netting arrangements and qualify for net presentation in our consolidated balance sheets at December 31, 2017, and (ii) the net recorded fair value as reflected on our consolidated balance sheets at December 31, 2017. At December 31, 2018, we did not have any commodity or foreign exchange derivative contracts.

		As of December 31, 2017		
Underlying Commodity	Location on Balance Sheet	Gross Amount of Recognized Assets	Gross Amount Offset in the Consolidated Balance Sheet (in thousands)	Net Amount of Assets Presented in the Consolidated Balance Sheet
Crude oil	Current liabilities	$ 2,215	$ –	$ 2,215

8. Asset retirement obligations

As part of our development of oil and natural gas properties, we incur asset retirement obligations ("ARO"). Our ARO results from our responsibility to abandon and reclaim our net share of all working interest properties and facilities. At December 31, 2018, the net present value of our total ARO was estimated to be $4.7 million, with the undiscounted value being $8.2 million. Total ARO at December 31, 2018 shown in the table below consists of amounts for future plugging and abandonment liabilities on our wellbores and facilities based on third-party estimates of such costs, adjusted for inflation at a rate of approximately 12.65% per annum for Turkey. These values are discounted to present value using our credit-adjusted risk-free rate of 7.55% per annum for Turkey for the year ended December 31, 2018. The following table summarizes the changes in our ARO for the years ended December 31, 2018 and 2017:

	2018	2017
	(in thousands)	
Asset retirement obligations at beginning of period	$ 4,727	$ 4,833
Liabilities settled	–	(37)
Foreign exchange change effect	(1,270)	(259)
Additions	1,036	–
Accretion expense	174	190
Asset retirement obligations at end of period	4,667	4,727
Long-term portion	$ 4,667	$ 4,727

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.

9. Loans payable

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

Fixed and floating rate loans	December 31, 2018	December 31, 2017
	(in thousands)	
Term Loan (1)	$ 22,000	$ 28,625
Loans payable	22,000	28,625
Less: current portion	22,000	15,625
Long-term portion	$ –	$ 13,000

(1) Includes 2018, 2017 and 2016 Term Loans.

2016 Term Loan

On August 31, 2016, DenizBank entered into a $30.0 million term loan (the "2016 Term Loan") with TransAtlantic Exploration Mediterranean International Pty Ltd ("TEMI") under our general credit agreement with DenizBank (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 Mr. Mitchell and 20% 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 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.

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 had a grace period which bore no interest or payments due until July 2018. Thereafter, the 2017 Term Loan 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 Mr. Mitchell and 20% Mr. 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 December 31, 2018, we had $13.0 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.

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 had a grace period through July 2018 during which no payments were 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 Mr. Mitchell and 20% Mr. 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 December 31, 2018, we had $9.0 million outstanding under the 2018 Term Loan and no availability, and we were in compliance with the covenants in the 2018 Term Loan.

During the years ended December 31, 2018 and 2017, we recorded interest expense related to the 2016, 2017 and 2018 Term Loan of $1.8 million and $0.9 million, respectively.

2017 Notes

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, Mr. Mitchell, 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 (the "Initial Advance"). The Initial Advance was used 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 ANBE 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 December 31, 2018, we had no outstanding borrowings under these lines of credit.

Loan financing costs

We capitalize certain costs in connection with obtaining our borrowings, such as lender's fees and related attorney's fees. These costs are amortized on a straight line basis, which approximates the effective interest method over the term of the loan as a component of interest expense. Amortization of loan financing costs totaled approximately $0.1 million during 2018 and 2017.

10. Shareholders' equity

Share issuances to holders of Series A Preferred Shares

On October 2, 2017, we issued an aggregate of 2,591,384 common shares to holders of the Series A Preferred Shares as payment of the September 30, 2017 quarterly dividend on the Series A Preferred Shares. Each common share was issued at a value of $0.7108 per common share, which was equal to the 15-day volume weighted average price through the close of trading of the common shares on the NYSE American exchange on September 13, 2017.

On December 31, 2018, we issued an aggregate of 1,808,001 common shares to holders of the Series A Preferred Shares as payment of the December 31, 2018 quarterly dividend on the Series A Preferred Shares. Each common share was issued at a value of $1.0188 per common share, which was equal to the 15-day volume weighted average price through the close of trading of the common shares on the NYSE American exchange on December 14, 2018.

Restricted stock units

Under our 2009 Long-Term Incentive Plan (the "Incentive Plan"), we awarded restricted stock units ("RSUs") and other share-based compensation to certain of our directors, officers, employees and consultants. Each RSU is equal in value to one of our common shares on the grant date. Upon vesting, an award recipient is entitled to a number of common shares equal to the number of vested RSUs. The RSU awards can only be settled in common shares. As a result, RSUs are classified as equity. At the grant date, we make an estimate of the forfeitures expected to occur during the vesting period and record compensation cost, net of the estimated forfeitures, over the requisite service period. The current forfeiture rate is estimated to be 12.5%.

Under the Incentive Plan, RSUs vest over specified periods of time ranging from immediately to four years. RSUs are deemed full value awards and their value is equal to the market price of our common shares on the grant date. ASC 718 requires that the Incentive Plan be approved in order to establish a grant date. Under ASC 718, the approval date for the Incentive Plan was February 9, 2009, the date our board of directors approved the Incentive Plan.

Share-based compensation of approximately $0.5 million and $0.7 million with respect to awards of RSUs was recorded for the years ended December 31, 2018 and 2017, respectively. As of December 31, 2018, we had approximately $0.3 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 0.5 years. The following table sets forth RSU activity for the year ended December 31, 2018:

	Number of RSUs (in thousands)	Weighted Average Grant Date Fair Value Per RSU
Unvested RSUs outstanding at December 31, 2017	513	$ 1.38
Granted	311	1.55
Forfeited	(7)	1.18
Vested	(363)	1.49
Unvested RSUs outstanding at December 31, 2018	454	$ 1.42

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 years ended December 31, 2018 and 2017 equals net income 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 RSUs. Diluted earnings per common share for the years ended December 31, 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 stock options, RSUs, preferred shares and warrants, whether exercisable or not. The computation of diluted earnings per common share excluded 42.0 million and 43.7 million antidilutive common share equivalents for the years ended December 31, 2018 and 2017, respectively.

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

(in thousands, except per share amounts)	2018	2017
Net loss	$ (5,216)	$ (23,875)
Basic net loss per common share:		
Shares:		
Weighted average common shares outstanding	50,505	48,196
Basic net loss per common share:	$ (0.10)	$ (0.50)
Diluted net loss per common share:		
Shares:		
Weighted average shares outstanding	50,505	48,196
Dilutive effect of:		
Restricted share units	–	–
2017 Notes	–	–
Weighted average common and common equivalent shares outstanding	50,505	48,196
Diluted net loss per common share:	$ (0.10)	$ (0.50)

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.

11. Income taxes

The income tax provision differs from the amount that would be obtained by applying the Bermuda statutory income tax rate of 0% for 2018 and 2017 to income (loss) from operations as follows:

	2018	2017
	(in thousands except rates)	
Statutory rate	0.00%	0.00%
Income (loss) before income taxes	$ 4,458	$ (18,446)
Increase (decrease) resulting from:		
Foreign tax rate differentials	$ 4,720	$ 945
Uncertain tax position	935	1,050
Unremitted earnings	2,927	1,677
Change in valuation allowance	(4,743)	640
Expiration of non-capital tax loss carryovers	4,793	792
Other	1,042	325
Total	$ 9,674	$ 5,429

The components of the net deferred income tax liability at December 31, 2018 and 2017 were as follows:

	2018	2017
	(in thousands)	
Deferred tax assets		
Property and equipment	$ 609	$ 1,279
Unrealized gains on derivative contracts		432
Timing of accruals	574	132
Non-capital loss carryovers	13,261	16,502
Valuation allowance	(13,261)	(17,731)
Other	–	47
Total deferred tax assets	$ 1,183	$ 661
Deferred tax liabilities		
Property and equipment	$ (9,728)	$ (10,044)
Unremitted earnings	(9,401)	(9,631)
Timing of accruals	(2,368)	(597)
Total deferred tax liabilities	(21,497)	(20,272)
Net deferred tax liabilities	$ (20,314)	$ (19,611)
Components of net deferred tax liabilities		
Non-current assets	$ 1,183	$ 661
Non-current liabilities	(21,497)	(20,272)
Net deferred tax liabilities	$ (20,314)	$ (19,611)

We have accumulated losses or resource-related deductions available for income tax purposes in Turkey, Romania, Bulgaria and the United States. As of December 31, 2018, we had non-capital tax losses in Turkey of approximately 57.8 million TRY (approximately $11.0 million), which will begin to expire in 2019; non-capital tax losses in Romania of approximately 1.6 million Romanian New Leu (approximately $0.4 million), which will begin to expire in 2019; non-capital losses in Bulgaria of approximately 9.8 million Bulgarian Lev (approximately $5.7 million), which will begin to expire in 2019; and non-capital tax losses in the United States of approximately $53.7 million, which will begin to expire in 2019. As of December 31, 2018 and 2017, we recorded a valuation allowance of $13.3 million and $17.7 million, respectively, as a reduction to our net operating losses and deferred tax assets.

Effective October 1, 2009, we continued to the jurisdiction of Bermuda under the Bermuda *Companies Act 1981*. We have determined that no taxes were payable upon the continuance. However, our tax filing positions are still subject to review by taxation authorities who may successfully challenge our interpretation of the applicable tax legislation and regulations, with the result that additional taxes could be payable by us.

We file income tax returns in the United States, Turkey, Bulgaria and Cyprus, with Turkey being the only jurisdiction with significant amounts of taxes due. Except for the outstanding examination of the 2011 income tax filings for Petrogas, Turkish income tax filings before 2012 are no longer subject to examination. As the result of 2016 Turkish legislation allowing us the option to enter into an agreement to exempt corporate income tax filings from examination, we were able to close additional years from examination.

As of December 31, 2018 and 2017, we recorded a $6.7 million and $8.7 million liability, respectively, primarily due to uncertain tax positions related to the unwinding of all our crude oil hedge collars and three-way contracts, which are included in long-term accrued liabilities on our consolidated balance sheet. The unrecognized tax benefits at December 31, 2018 and 2017 were as follows:

	2018	2017
	(in thousands)	
Unrecognized tax benefits at beginning of period	$ 8,663	$ 8,079
Gross increases - tax positions in prior period	935	1,125
Foreign exchange change effect	(2,884)	(541)
Unrecognized tax benefits at end of period	$ 6,714	$ 8,663

As of December 31, 2018, there were no material uncertain tax positions for which the total amounts of unrecognized tax benefits will significantly increase or decrease within the next 12 months.

Unremitted earnings

Our foreign subsidiaries generate earnings that are not subject to Turkish dividend withholding taxes so long as they are permanently reinvested in our operations in Turkey. Pursuant to ASC Topic No. 740-30, undistributed earnings of foreign subsidiaries that are no longer permanently reinvested would become subject to Turkish dividend withholding taxes. Prior to fiscal year 2015, we asserted that the undistributed earnings of our foreign Turkish subsidiaries were permanently reinvested.

Primarily due to the increase in our U.S. debt service obligations resulting from the issuance of the 2017 Notes in the aggregate principal amount of $55.0 million in 2015 (see Note 9 "Loans payable"), management concluded that the ability to access certain amounts of foreign earnings would provide greater flexibility to meet corporate cash flow needs without constraining foreign objectives. Accordingly, in the fourth quarter of fiscal year 2015, we withdrew the permanent reinvestment assertion on 135.2 million TRY of cumulative earnings generated by certain of our Turkish foreign subsidiaries through fiscal year 2015. We provided for Turkish dividend withholding taxes on the 135.2 million TRY of cumulative undistributed foreign Turkish earnings, resulting in the recognition of a deferred tax liability. Although the 2017 Notes were retired on July 3, 2017 (see Note 9 "Loans Payable"), due to our obligation to pay dividends on our Series A Preferred Shares issued on November 4, 2016 (see Note 5 "Series A Preferred Shares"), as of December 31, 2018 and 2017, we maintain the same position, and we provided for Turkish dividend, withholding taxes on 329.7 million and 242.1 million TRY, respectively, of cumulative undistributed foreign Turkish earnings, resulting in an additional increase in our deferred tax liability.

There is no certainty as to the timing of when or if such Turkish foreign earnings will be distributed in whole or in part.

12. Segment information

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

	Corporate	Turkey	Bulgaria	Total
		(in thousands)		
For the year ended December 31, 2018				
Total revenues	$ –	$ 70,789	$ –	$ 70,789
Production	–	10,649	120	10,769
Transportation costs	–	4,665	–	4,665
Exploration, abandonment, and impairment	–	401	–	401
Seismic and other exploration	–	488	1	489
General and administrative	9,222	5,344	153	14,719
Depreciation, depletion and amortization	142	13,917	–	14,059
Accretion of asset retirement obligations	–	151	23	174
Total costs and expenses	9,364	35,615	297	45,276
Operating (loss) income	(9,364)	35,174	(297)	25,513
Interest and other expense	(7,026)	(3,022)	–	(10,048)
Interest and other income	184	897	1	1,082
Loss on commodity derivative contracts	–	(1,797)	–	(1,797)
Foreign exchange gain (loss)	(351)	(9,932)	(9)	(10,292)
(Loss) income before income taxes	(16,557)	21,320	(305)	4,458
Income tax expense	–	(9,674)	–	(9,674)
Net loss	$ (16,557)	$ 11,646	$ (305)	$ (5,216)
Total assets at December 31, 2018	$ 8,358	$ 122,325	$ 1,917	$ 132,600
Capital expenditures for the year ended December 31, 2018	$ –	$ 23,517	$ –	$ 23,517
For the year ended December 31, 2017				
Total revenues	$ –	$ 56,639	$ –	$ 56,639
Production	36	12,136	77	12,249
Exploration, abandonment, and impairment	–	934	–	934
Cost of purchased natural gas	–	568	–	568
Seismic and other exploration	–	4,723	–	4,723
General and administrative	6,739	5,729	349	12,817
Depreciation, depletion and amortization	188	16,737	–	16,925
Accretion of asset retirement obligations	–	169	21	190
Total costs and expenses	6,963	40,996	447	48,406
Operating (loss) income	(6,963)	15,643	(447)	8,233
Loss on sale of TBNG	(15,226)	–	–	(15,226)
Interest and other expense	(7,794)	(1,044)	–	(8,838)
Interest and other income	250	847	1	1,098
Loss on commodity derivative contracts	–	(1,852)	–	(1,852)
Foreign exchange gain (loss)	365	(2,239)	13	(1,861)
(Loss) income before income taxes	(29,368)	11,355	(433)	(18,446)
Income tax expense	–	(5,429)	–	(5,429)
Net loss	$ (29,368)	$ 5,926	$ (433)	$ (23,875)
Total assets at December 31, 2017	$ 61,167	$ 109,699	$ (10,216)	$ 160,650
Capital expenditures for the year ended December 31, 2017	$ –	$ 15,854	$ –	$ 15,854

13. Financial instruments

Foreign currency risk

We have underlying foreign currency exchange rate exposure. Our currency exposures primarily relate to transactions denominated in the Bulgarian Lev, European Union Euro, and 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. We have not used foreign currency forward contracts to manage exchange rate fluctuations. At December 31, 2018 and 2017, we had 7.8 million TRY and $4.0 million TRY, respectively (approximately $1.5 million and $1.1 million, respectively) in cash and cash equivalents, which exposes us to exchange rate risk based on fluctuations in the value of the TRY.

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.

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 three financial institutions in the United States and Turkey.

Fair value measurements

Cash and cash equivalents, receivables, notes receivable, accounts payable, accrued liabilities and the ANBE Note were each estimated to have a fair value approximating the carrying amount at December 31, 2018 and 2017 due to the short maturity of those instruments.

The financial assets and liabilities measured on a recurring basis at December 31, 2017 consisted of our commodity derivative contracts. Fair values for options are based on counterparty market prices. The counterparties use market standard valuation methodologies incorporating market inputs for volatility and risk free interest rates in arriving at a fair value for each option contract. Prices are verified by us using analytical tools. There are no performance obligations related to the collar contracts purchased to hedge our oil production.

We utilize models based on a range of observable market inputs, including pricing models, quoted market prices of publicly traded securities with similar duration and yield, time value, yield curve, prepayment spreads, default rates and discounted cash flow and the values for these contracts are disclosed in Level 2 of the fair value hierarchy to determine the fair value of our commodity derivative contracts. We review prices received from our counterparty for unusual fluctuations to ensure that the prices represent a reasonable estimate of fair value.

At December 31, 2018, the fair value of the 2018 Term Loan and 2017 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. At December 31, 2018, the carrying value approximated the fair value for the 2018 Term Loan and 2017 Term Loan. The following table summarizes the valuation of our financial liabilities as of December 31, 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)			
Liabilities:				
2017 Term Loan	–	–	(11,938)	(11,938)
2018 Term Loan	–	–	(8,192)	(8,192)
Total	$ –	$ –	$ (20,130)	$ (20,130)

The following table summarizes the valuation of our financial 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)

14. Commitments

Our aggregate annual commitments, other than our loans payable, as of December 31, 2018 were as follows:

	Payments Due By Year						
	Total	2019	2020	2021	2022	2023	Thereafter
	(in thousands)						
Series A Preferred Shares dividends (1)	$ 37,822	$ 5,526	$ 5,526	$ 5,526	$ 5,526	$ 5,526	$ 10,192
Interest	800	800	-	-	-	-	-
Leases	3,251	963	710	636	626	316	-
Total	$ 41,873	$ 7,289	$ 6,236	$ 6,162	$ 6,152	$ 5,842	$ 10,192

(1) Dividends on the Series A Preferred Shares may be paid by us, in our sole discretion, in cash at a rate of 12% per annum or in common shares at a rate of 16% per annum or in a combination of cash and common shares. The amounts in the table assume that we pay all future dividend payments solely in cash.

Normal operations purchase arrangements are excluded from the table as they are discretionary or being performed under contracts which are cancelable immediately or with a 30-day notice period.

We lease office space in Dallas, Texas, Bulgaria, and Turkey. We also lease apartments in Turkey, as well as operations yards in Turkey. Rent expense for the years ended December 31, 2018 and 2017 was $1.3 million and $1.2 million, respectively.

15. Contingencies

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.

Morocco

During 2012, we were notified that the Moroccan government may seek to recover approximately $5.5 million in contractual obligations under our Tselfat exploration permit work program. In February 2013, the Moroccan government drew down our $1.0 million bank guarantee that was put in place to ensure our performance of the Tselfat exploration permit work program. Although we believe that the bank guarantee satisfies our contractual obligations, we recorded $5.0 million in accrued liabilities relating to our

Tselfat exploration permit during 2012 for this contingency. In September 2016, management determined that, because it had received no communication from the Moroccan government since early 2013, the probability of payment of this contingency is remote, and therefore we reversed the $6.0 million in contingent liabilities previously classified as liabilities held for sale.

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. In November 2018, the Sofia Court of Appeal concluded that the judgement of the Sofia City Court was correct and, therefore, dismissed the Bulgarian Minister of Energy's appeal. In January 2019, the Bulgarian Minister of Energy filed an appeal in the Supreme Court of Cassation. We continue to vigorously defend this claim.

As a result of the judgement of the Sofia Court of Appeal, we are currently evaluating an adjustment to our contingencies relating to production leases and exploration permits.

16. Related party transactions

Series A Preferred Shares transactions

On November 4, 2016, we issued 921,000 Series A Preferred Shares. Of the 921,000 Series A Preferred Shares, (i) 815,000 shares were issued in exchange for $40.75 million of our 2017 Notes, at an exchange rate of 20 Series A Preferred Shares for each $1,000 principal amount of 2017 Notes (the "Exchange Offer"), and (ii) 106,000 shares were issued and sold for $5.3 million of cash to certain holders of the 2017 Notes (the "Offering"). In the Exchange Offer, Pinon Foundation, a non-profit charitable organization directed by Mr. Mitchell's spouse exchanged $10.0 million of the 2017 Notes for 200,000 Series A Preferred Shares; Dalea exchanged $2.1 million of the 2017 Notes for 41,000 Series A Preferred Shares; and trusts benefitting Mr. Mitchell's four adult children each exchanged $2.0 million of the 2017 Notes for 40,000 Series A Preferred Shares. In the Offering, the Pinon Foundation purchased 5,000 Series A Preferred Shares for $250,000; and each of Mr. Mitchell's four adult children purchased 1,000 Series A Preferred Shares for $50,000. Pinon Foundation subsequently sold its Series A Preferred Shares to Longfellow Energy, LP, an affiliate of Mr. Mitchell. For more information see Note 5 "Series A Preferred Shares".

Equity transactions

On December 31, 2014, April 24, 2015 and August 13, 2015, we issued 134,169, 134,168 and 134,168 Warrants, respectively, to Mr. Mitchell and 23,333, 23,333 and 23,333 Warrants, respectively, to each of Mr. Mitchell's children, as shareholders of Gundem, as consideration for the pledge of Turkish real estate in exchange for an extension of the maturity date 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 issued in December 2014, April 2015 and August 2015 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.

On June 30, 2016, we issued an aggregate of 5,773,305 common shares in private placements under the Securities Act. Of the 5,773,305 common shares, (i) 1,974,452 common shares were issued to Dalea, the trusts of Mr. Mitchell's four adult children and Pinon Foundation, at their election to receive common shares in lieu of cash interest on the 2017 Notes; (ii) 355,826 common shares were issued to ANBE in lieu of cash interest on the ANBE Note and (iii) 814,627 common shares were issued to Dalea and the trusts of Mr. Mitchell's four adult children for cash, which was used to pay cash interest to certain holders of the 2017 Notes (see Note 10 "Shareholders' equity").

On December 5, 2016, Randy Rochman, chief executive officer of West Family Investments, and Jonathon Fite, co-owner of the general partner of KMF Investment Partners, LP, were appointed to our board of directors. Randy Rochman and KMF Investment Partners, LP held, and currently hold, 15,000 and 69,000 Series A Preferred Shares, respectively. On March 31, 2017, these 84,000 shares ($4.2 million in value) were re-classified to related party.

On October 2, 2017, we issued an aggregate of 2,591,384 common shares to holders of the Series A Preferred Shares as payment of the September 30, 2017 quarterly dividend on the Series A Preferred Shares (see Note 10 "Shareholder's Equity"). Of the 2,591,384 common shares, 1,392,768 common shares were issued to Dalea, the trusts of Mr. Mitchell's four children, Pinon Foundation, a nonprofit entity controlled by Mrs. Mitchell, KMF Investment Partners, LP, and Randy Rochman.

On December 31, 2018, we issued an aggregate of 1,808,001 common shares to holders of the Series A Preferred Shares as payment of the December 31, 2018 quarterly dividend on the Series A Preferred Shares (see Note 10 "Shareholder's Equity"). Of the 1,808,001 common shares, 971,724 common shares were issued to Dalea, the trusts of Mr. Mitchell's four children, Longfellow Energy, an entity controlled by Mr. Mitchell, KMF Investment Partners, LP, and Randy Rochman.

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, 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 $8.0 million 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 ("Viking International"). 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 former subsidiaries, Viking International and Viking Geophysical Services Ltd. ("Viking Geophysical") 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 B.V., the beneficial owner of Viking International, VOS and Viking Geophysical ("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 Master Services Agreement, dated March 3, 2016, by and between Production Solutions International Petrol Arama Hizmetleri Anomin Sirketi ("PSI"), an affiliate of Mr. Mitchell, and TEMI (the "PSI MSA"). PSI 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 PSI to less than 50%; (ii) the sale or transfer by Dalea or PSI of all or substantially all of its assets to any person (a "Transferee") that does not own a controlling interest in Dalea or PSI 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 PSI; (iv) termination of the PSI MSA other than as a result of an uncured default thereunder by TEMI; (v) default by PSI under the PSI MSA, which default is not remedied within a period of 30 days after notice thereof to PSI; and (vi) insolvency or bankruptcy of PSI. 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 the 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.

As of December 31, 2018 and 2017, the amount receivable under the Amended Note was $5.8 million and $6.7 million, respectively.

On February 28, 2019, we and Dalea entered into an amendment (the "Note Amendment") to the Amended Note (as amended by the Note Amendment, the "Note"), pursuant to which we and Dalea agreed to extend the maturity date of the Note to February 26, 2021 (unless otherwise accelerated in accordance with the terms of the Note).

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 certain 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 Messrs. Mitchell and Uras a fee of 5% per annum of the collateral value of the Diyarbakir real estate. 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 will be used to reduce the outstanding principal amount of the Amended Note. During the year ended December 31, 2018 and 2017, we reduced the principal amount of the Amended Note by $0.6 million for amounts earned under the pledge fee agreements.

Service 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"). 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 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.

On June 13, 2012, we entered into separate master services agreements with each of Viking International, Viking Petrol Sahasi Hizmetleri AS ("VOS") and Viking Geophysical in connection with the sale of our oilfield services business to a joint venture owned by Dalea and funds managed by Abraaj Investment Management Limited. Pursuant to the master services agreements with Viking International and VOS, we are entitled to receive certain oilfield services and materials, including, but not limited to, drilling rigs and fracture stimulation that are needed for our operations in Bulgaria and Turkey. Pursuant to the master services agreement with Viking Geophysical, we are also entitled to receive geophysical services and materials that are needed for our operations in those countries. Each master services agreement is for a five-year term, with automatic one-year extensions absent notice of termination from either party. Currently, we can contract for services and materials on a firm basis and, to the extent that we do not contract for all of their services or materials, Viking International, VOS and Viking Geophysical are allowed to contract with third parties for any remaining capacity.

On March 3, 2016, Mr. Mitchell closed a transaction whereby he sold his interest in Viking Services 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 PSI. PSI is beneficially owned by Dalea Investment Group, LLC, which is controlled by Mr. Mitchell. Consequently, on March 3, 2016, TEMI entered into the PSI MSA on substantially similar terms to our prior master services agreements with Viking International, VOS and VGS. Pursuant to the PSI MSA, PSI will perform services on behalf of TEMI and its affiliates. On February 28, 2019, TEMI and PSI entered into an amendment (the "PSI MSA Amendment") to the PSI MSA, pursuant to which PSI and TEMI agreed to extend the primary term of the PSI MSA to February 26, 2021, with automatic successive renewal terms of one (1) year each, unless terminated by PSI or TEMI by written notice at least sixty (60) days prior to the end of the primary term or any successive renewal term. The master services agreements with each of Viking International, VOS and Viking Geophysical currently remain in effect.

On August 7, 2018 and effective as of June 14, 2018, our wholly owned subsidiary, TransAtlantic USA, entered into a sublease agreement (the “Sublease”) with Longfellow to lease corporate office space located at 16803 North Dallas Parkway, Addison, Texas. 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.

On March 20, 2017, we entered into a second amendment to the Master Services Agreement among us and Longfellow Energy, LP, a Texas limited partnership, Viking Drilling, LLC, a Nevada limited liability company, RIATA Management, LLC, an Oklahoma limited liability company, 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 Riata Entities and expanding the scope of services.

For the years ended December 31, 2018 and 2017, we incurred capital and operating expenditures of $10.6 million and $9.3 million, respectively, related to our various related party agreements.

ANBE Note

On December 30, 2015, TransAtlantic USA entered into the $5.0 million Note with ANBE, an entity owned by the children of our chairman and chief executive officer, Mr. Mitchell and controlled by an entity managed by Mr. Mitchell and his wife. The ANBE Note bears interest at a rate of 13.0% per annum. On December 30, 2015, we borrowed the Initial Advance of $3.6 million for general corporate purposes. On June 30, 2016, we issued 355,826 common shares in a private placement to-ANBE in lieu of paying cash interest on the ANBE Note.

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 ANBE 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 and terminated it with proceeds from the sale of TBNG.

The following table summarizes related party accounts receivable and accounts payable as of December 31, 2018 and December 31, 2017:

	2018	2017
	(in thousands)	
Related party accounts receivable:		
Riata Management Service Agreement	$ 526	$ 576
PSI MSA	352	447
Total related party accounts receivable	$ 878	$ 1,023
Related party accounts payable:		
Riata Management Service Agreement	$ 372	$ 341
PSI MSA	2,439	2,119
Board of Directors	111	–
Interest payable on Series A Preferred Shares	–	681
Total related party accounts payable	$ 2,922	$ 3,141

17. Divestitures and discontinued operations

TBNG

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

Although the sale of TBNG met the threshold to classify its assets and liabilities as held for sale, it did not meet the requirements to classify its operations as discontinued as the sale was not 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 net cash proceeds of $16.1 million, effective as of March 31, 2016. The purchase price was subject to post-closing adjustments, and we agreed to escrow $3.1 million of the purchase price for 30 days to satisfy any agreed upon purchase price adjustments. We agreed to a $0.2 million reduction to the purchase price, and on April 10, 2017, we collected $2.9 million of the escrowed funds.

For the year ended December 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. The calculation of the loss on sale is 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)

Discontinued operations in Albania

As of December 31, 2015, we classified our Albania segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented.

In February 2016, we sold all of the outstanding equity in our wholly-owned subsidiary, Stream Oil & Gas Ltd. ("Stream"), to GBC Oil Company.

On September 1, 2016, we completed a joint venture transaction with respect to the assets in the Delvina gas field in Albania (the "Delvina Assets"). We transferred (the "Transfer") 75% of the outstanding shares of Delvina Gas Company Ltd. ("DelvinaCo"), which owned the Delvina Assets, to Ionian Gas Company Ltd. ("Ionian") in exchange for Ionian's agreement to pay $12.0 million to DelvinaCo, which was to be used primarily to repay debt and for general corporate purposes with respect to the Delvina Assets. After the Transfer, we retained a 25% equity interest in DelvinaCo and agreed to pay 25% of the operating costs of DelvinaCo, subject to a three-year deferral of capital expenditures.

On August 9, 2017, due to continued failures by our joint venture partners to timely meet their obligations, uncompleted local governmental ratifications, and our prioritization of funds, we transferred our 25% equity interest in DelvinaCo to Delvina Investment Partners Ltd. in exchange for a release of all claims with respect to DelvinaCo and a cash payment of $300,000 for amounts owed to us under agreements entered into in connection with the DelvinaCo joint venture transaction. Additionally, we terminated all of our responsibilities as operator and our obligations to pay any operating costs or any other expenditures with respect to DelvinaCo. This divestiture completed our departure from all Albanian operations and assets.

18. Subsequent events

2019 Term Loan

On February 22, 2019, TEMI entered into a $20.0 million term loan (the "2019 Term Loan") with DenizBank under the Credit Agreement.

The 2019 Term Loan bears interest at a fixed rate of 7.5% (plus 0.375% for Banking and Insurance Transactions Tax per the Turkish government) per annum. The 2019 Term Loan has a ten-month grace period during which the 2019 Term Loan bears interest but no payments are due other than a single interest only payment of $0.76 million in August 2019. After the ten-month grace period, the 2019 Term Loan is payable in fourteen monthly principal installments of $1.43 million plus interest. The 2019 Term Loan matures in February 2021. Amounts repaid under the 2019 Term Loan may not be re-borrowed, and early repayments under the 2019 Term Loan are subject to early repayment fees.

The 2019 Term Loan is guaranteed by Petrogas, Amity, Talon Exploration, DMLP, and TransAtlantic Turkey.

The 2019 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 2019 Term Loan prohibits Amity, Talon Exploration, DMLP, and Transatlantic Turkey from incurring additional debt. An event of default under the 2019 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 2019 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 Mr. Mitchell and 20% by Mr. Uras, and (vi) certain Ankara real estate owned 100% by Mr. Uras. In addition, TEMI has assigned its Turkish collection accounts and its receivables from the sale of oil to the Lender as additional security for the 2019 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 the Board. Mr. Uras is our Vice President, Turkey.

Note Amendment

On February 28, 2019, we and Dalea entered into the Note Amendment to the Amended Note, pursuant to which we and Dalea agreed to extend the maturity date of the Note to February 26, 2021 (unless otherwise accelerated in accordance with the terms of the Note).

PSI MSA Amendment

On February 28, 2019, TEMI and PSI entered into an amendment (the “PSI MSA Amendment”) to the PSI MSA, pursuant to which PSI and TEMI agreed to extend the primary term of the PSI MSA to February 26, 2021, with automatic successive renewal terms of one year each, unless terminated by PSI or TEMI by written notice at least 60 days prior to the end of the primary term or any successive renewal term.

Supplemental Information
(unaudited)

Supplemental quarterly financial data (unaudited)

The following table summarizes results for each of the four quarters in the years ended December 31, 2018 and 2017.

	Three Months Ended (1)			
	March 31,	June 30,	September 30,	December 31,
	(in thousands, except per share data)			
For the year ended December 31, 2018:				
Revenues	$ 16,926	$ 18,198	$ 20,140	$ 15,525
Net loss	(1,775)	(1,006)	(1,720)	(715)
Comprehensive (loss) income	(4,118)	(10,115)	(13,485)	5,247
Basic and diluted net loss per common share	$ (0.04)	$ (0.02)	$ (0.03)	$ (0.01)
For the year ended December 31, 2017:				
Revenues	$ 16,436	$ 12,341	$ 12,675	$ 15,187
Net (loss) income	(16,049)	566	(4,353)	(4,039)
Comprehensive income (loss)	4,870	2,698	(5,576)	(10,317)
Basic and diluted net (loss) income per common share	$ (0.34)	$ 0.01	$ (0.09)	$ (0.08)

(1) The sum of the individual quarterly net (loss) income amounts per share may not agree with full year net (loss) income per share as each quarterly computation is based on the net income or loss for that quarter and the weighted-average number of shares outstanding during that quarter.

Supplemental oil and natural gas reserves information (unaudited)

As required by the FASB and the SEC, the standardized measure of discounted future net cash flows (the “Standardized Measure”) presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10% to proved reserves. We do not believe the Standardized Measure provides a reliable estimate of our expected future cash flows to be obtained from the development and production of our oil and natural gas properties or of the value of our proved oil and natural gas reserves. The Standardized Measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year-to-year as prices change.

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, revisions to existing reserves estimates may occur from time to time. Although every reasonable effort is made to ensure reserves estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. We engaged DeGolyer & MacNaughton to prepare our reserves estimates in Turkey and Bulgaria.

The following unaudited schedules are presented in accordance with required disclosures about oil and natural gas producing activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies.

All of our proved reserves are located in Turkey and all prices are held constant in accordance with SEC rules.

Oil and natural gas prices used to estimate reserves were computed by applying the volume-weighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 2018 and 2017. The oil and natural gas prices used to estimate reserves are shown in the table below.

	12-Month Average Price	
	Oil per (Bbl)	Natural Gas per (Mcf)
Turkey		
2018	$ 64.91	$ 4.82
2017	$ 47.57	$ 3.98

The following table sets forth our estimated net proved reserves, including changes therein, and proved developed reserves:

Disclosure of reserves quantities

	Turkey	Albania(1)	TBNG(2)	Total
	Oil (Mbbls)			
Total proved reserves				
December 31, 2016	12,730	52	3	12,785
Revisions of previous estimates	3,156	(52)	-	3,104
Sale of reserves	-	-	(2)	(2)
Sales volumes	(1,103)	-	(1)	(1,104)
December 31, 2017	14,783	-	-	14,783
Revisions of previous estimates	(5,872)	-	-	(5,872)
Extensions and discoveries	2,085	-	-	2,085
Sales volumes	(1,020)	-	-	(1,020)
December 31, 2018	9,976	-	-	9,976
Proved developed reserves				
December 31, 2017:				
Proved developed producing	3,998	-	-	3,998
Proved developed non-producing	217	-	-	217
Total	4,215	-	-	4,215
December 31, 2018:				
Proved developed producing	4,575	-	-	4,575
Proved developed non-producing	472	-	-	472
Total	5,047	-	-	5,047
Proved undeveloped reserves				
As of December 31, 2017	10,568	-	-	10,568
As of December 31, 2018	4,929	-	-	4,929

	Turkey	Albania(1)	TBNG(2)	Total
		Gas (Mmcf)		
Total proved reserves				
December 31, 2016	5,212	1,411	9,037	15,660
Revisions of previous estimates	(742)	(1,411)	-	(2,153)
Sale of reserves	-	-	(8,973)	(8,973)
Sales volumes	(312)	-	(64)	(376)
December 31, 2017	4,158	-	-	4,158
Revisions of previous estimates	(1,506)	-	-	(1,506)
Sales volumes	(212)	-	-	(212)
December 31, 2018	2,440	-	-	2,440
Proved developed reserves				
December 31, 2017:				
Proved developed producing	1,671	-	-	1,671
Proved developed non-producing	1,206	-	-	1,206
Total	2,877	-	-	2,877
December 31, 2018:				
Proved developed producing	424	-	-	424
Proved developed non-producing	1,833	-	-	1,833
Total	2,257	-	-	2,257
Proved undeveloped reserves				
As of December 31, 2017	1,281	-	-	1,281
As of December 31, 2018	184	-	-	184

(1) We classified our Albanian segment as assets and liabilities held for sale and presented the operating results within discontinued operations for all periods presented before 2018.
(2) Consists of amounts related to our TBNG assets that were sold in February 2017.

Proved Reserves

Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors. See “Oil and Natural Gas Reserves under U.S. Law.”

At December 31, 2018, our estimated proved reserves, were 10,383 Mboe, a decrease of 5,093 Mboe, or 33%, compared to 15,476 Mboe at December 31, 2017. This decrease was primarily attributable to revisions of previously estimated recoveries from planned wells in the Selmo field following revisions to our drilling plans in light of the expiration of our Selmo production lease in 2025, which resulted in a decrease of 3,680 Mboe, and from planned wells in the Bahar field following the establishment of the oil/water contact for the Bahar field, which resulted in a decrease of 2,618 Mboe. Additionally, proved reserves decreased 1,055 Mboe for volumes sold. This decrease was partially offset by a 2,045 Mboe increase in proved reserves due to the discovery of productive pay in the Yeniev oil field.

Proved Undeveloped Reserves

At December 31, 2018, our estimated proved undeveloped reserves were 4,960 Mboe, a decrease of 5,821 Mboe, or 54%, compared to 10,781 Mboe at December 31, 2017. The decrease in proved undeveloped reserves was primarily attributable to revisions of previously estimated recoveries from planned wells in the Selmo field following revisions to our drilling plans in light of the expiration of our Selmo production lease in 2025, which resulted in a decrease of 3,680 Mboe, and from planned wells in the Bahar field following the establishment of the oil/water contact for the Bahar field, which resulted in a decrease of 2,618 Mboe. This decrease was partially offset by a 1,373 Mboe increase in proved undeveloped reserves due to the discovery of productive pay in the Yeniev oil fields. All of our proved undeveloped reserves as of December 31, 2018 will be developed within five years of the date the reserve was first disclosed as a proved undeveloped reserve. The estimated undiscounted capital costs associated with our proved undeveloped reserves in Turkey is $56.0 million.

The proved undeveloped reserves assume development costs will be funded from future cash flows from operations and financing activities, which may not be sufficient or available at commercially economic terms and could impact the timing of these development activities.

Standardized measure of discounted future net cash flows

The Standardized Measure relating to estimated proved reserves as of December 31, 2018 and 2017 are shown in the table below. In our calculation of Standardized Measure, we have utilized statutory tax rate of 22% for Turkey. DeGolyer and MacNaughton did not estimate the Standardized Measure or future income tax expense.

	Total (in thousands)
As of and for the year ended December 31, 2018	
Future cash inflows	$ 659,435
Future production costs	(122,767)
Future development costs	(56,893)
Future income tax expense	(77,533)
Future net cash flows	402,242
10% annual discount for estimated timing of cash flows	(136,085)
Standardized measure of discounted future net cash flows related to proved reserves	$ 266,157
As of and for the year ended December 31, 2017	
Future cash inflows	$ 720,106
Future production costs	(144,871)
Future development costs	(163,315)
Future income tax expense	(54,409)
Future net cash flows	357,511
10% annual discount for estimated timing of cash flows	(130,378)
Standardized measure of discounted future net cash flows related to proved reserves	$ 227,133

Changes in the standardized measure of discounted future net cash flows

The following are the principal sources of changes in the Standardized Measure applicable to proved oil and natural gas reserves for the years ended December 31, 2018 and 2017.

	Turkey	Albania	TBNG (1)	Total
		(in thousands)		
For the year ended December 31, 2018				
Standardized measure, January 1,	$ 227,133	$ -	$ -	$ 227,133
Net change in sales and transfer prices and in production (lifting) costs related to future production	139,915	-	-	139,915
Changes in future estimated development costs	55,559	-	-	55,559
Sales and transfers of oil and natural gas during the period	(58,797)	-		(58,797)
Net change due to extensions and discoveries	72,036	-		72,036
Net change due to revisions in quantity estimates	(211,509)	-	-	(211,509)
Previously estimated development costs incurred during the period	23,285	-	-	23,285
Accretion of discount	27,955	-	-	27,955
Other	6,033		-	6,033
Net change in income taxes	(15,453)	-	-	(15,453)
Standardized measure, December 31,	$ 266,157	$ -	$ -	$ 266,157
For the year ended December 31, 2017				
Standardized measure, January 1,	$ 126,538	$ 738	$ 17,658	$ 144,934
Net change in sales and transfer prices and in production (lifting) costs related to future production	83,470	-	-	83,470
Changes in future estimated development costs	(976)	-	-	(976)
Sales and transfers of oil and natural gas during the period	(42,830)	-	(480)	(43,310)
Net change due to sales of reserves	-	-	(17,178)	(17,178)
Net change due to revisions in quantity estimates	85,752	-	-	85,752
Previously estimated development costs incurred during the period	4,220	-	-	4,220
Accretion of discount	10,999	-	-	10,999
Other	(8,077)	(738)	-	(8,815)
Net change in income taxes	(31,963)	-	-	(31,963)
Standardized measure, December 31,	$ 227,133	$ -	$ -	$ 227,133

(1) Consists of amounts related to our TBNG assets that were sold in February 2017.

Costs incurred in oil and natural gas property acquisition, exploration and development

Costs incurred in oil and natural gas property acquisition, exploration and development activities for the years ended December 31, 2018 and 2017 are summarized as follows:

	Total
	(in thousands)
For the year ended December 31, 2018	
Exploration	$ 12,079
Development	11,516
Total costs incurred	$ 23,595
For the year ended December 31, 2017	
Exploration	$ 11,568
Development	4,220
Total costs incurred	$ 15,788

Exhibit 31.1

CERTIFICATION

I, N. Malone Mitchell 3rd, certify that:

1. I have reviewed this Annual Report on Form 10-K of TransAtlantic Petroleum Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 26, 2019

/s/ N. Malone Mitchell 3rd
N. Malone Mitchell 3rd
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Michael P. Hill, certify that:

1. I have reviewed this Annual Report on Form 10-K of TransAtlantic Petroleum Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 26, 2019

/s/ Michael P. Hill
Michael P. Hill
Chief Accounting Officer
(Principal Financial Officer and Principal Accounting Officer)

Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of TransAtlantic Petroleum Ltd. (the “Company”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-K”), I, N. Malone Mitchell 3rd, Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 26, 2019

/s/ N. Malone Mitchell 3rd
N. Malone Mitchell 3rd
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to TransAtlantic Petroleum Ltd. and will be retained by TransAtlantic Petroleum Ltd. and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of TransAtlantic Petroleum Ltd. (the “Company”) for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-K”), I, Michael P. Hill Chief Accounting Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 26, 2019

/s/ Michael P. Hill
Michael P. Hill
Chief Accounting Officer
(Principal Financial Officer and Principal Accounting Officer)

A signed original of this written statement required by Section 906 has been provided to TransAtlantic Petroleum Ltd. and will be retained by TransAtlantic Petroleum Ltd. and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

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EXECUTIVE OFFICERS

N. Malone Mitchell 3rd
Chairman and Chief Executive Officer

Todd C. Dutton
President

Michael P. Hill
Chief Accounting Officer

Tabitha T. Bailey
Vice President, General Counsel,
and Corporate Secretary

G. Fabian Anda
Vice President of Finance

H. Lee Muncy
Vice President of Geosciences

AUDITORS

RBSM LLP

REGISTRAR & TRANSFER AGENT

Computershare Investor Services Inc.

COUNSEL

Akin Gump Strauss Hauer & Feld LLP

BOARD OF DIRECTORS

N. Malone Mitchell 3rd
Chairman and Chief Executive Officer: TransAtlantic Petroleum Ltd.; Founder: Riata Energy (renamed SandRidge Energy); Manager of General Partner: Longfellow Energy

Bob G. Alexander
Past President and Chief Executive Officer: National Energy Group, Inc.; Founder, Past Chairman, President and Chief Executive Officer: Alexander Energy Corp.

Brian E. Bayley
President: Earlston Management Corp.; Executive Chairman: Earlston Investments Corp.; Past Director and Resource Lending Advisor: Sprott Resource Lending Corp.

Charles J. Campise
Past Senior Vice President and Chief Financial Officer: Toreador Resources Corp.

Gregory K. Renwick
Past President and Chief Executive Officer: East West Petroleum Corp.; Past Director of Business Development: Dana Gas PJSC; Past Managing Director: Mobil Oil

Mel G. Riggs
Vice President: Clayton Williams Companies; Past President and Chief Operating Officer: Clayton Williams Energy, Inc.

Jonathon T. Fite
Managing Partner: KMF Investments, LP; Past Strategic Consultant: Accenture

Randall I. Rochman
Chief Executive Officer: West Family Investments, Inc.; Past Vice President, Investment Management Division: Goldman Sachs

CONTACT INFO

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and Corporate Secretary
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TNP on TSX