TRANSATLANTIC PETROLEUM LTD.
Form 10-K
March 16, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

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	None
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
16803 Dallas Parkway	
Addison, Texas	75001
(Address of principal executive offices)	(Zip Code)

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

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 MKT

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 x

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

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, 2014 (the last business day of the registrant's most recently completed second fiscal quarter), was approximately $257.1 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 6, 2015, there were 40,777,149 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 2015 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, 2014

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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: 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; future capital requirements and the availability of financing; estimates and economic assumptions used in connection with our acquisitions; 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; our ability to effectively integrate companies and properties that we acquire; 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; the allocation of capital expenditures to exploration and development activities; sources of funding for our capital expenditure programs; 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 the Company 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 production expenses and taxes.

Completion. The 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 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 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 assignment of 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 succession of sedimentary beds that were deposited under the same general geologic conditions.

Frac; fracture stimulation. A stimulation treatment involving the fracturing of a reservoir and then injecting water, sand and chemicals into the fractures under pressure 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 vertically to a certain depth and then drilled at a right angle with a specified interval.

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 costs of production.

Play. A term applied to 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.

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 mostly of consolidated clay or mud. 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, 2014, 2013 and 2012 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 after 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. 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, 2014, we held interests in approximately 1.8 million net acres of developed and undeveloped oil and natural gas properties in Turkey, Albania and Bulgaria. As of March 1, 2015, approximately 36% 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 reports prepared by DeGolyer and MacNaughton (for Turkey) and Deloitte LLP (for Albania), independent petroleum engineers, our estimated proved reserves at December 31, 2014 were approximately 32,749 Mboe, of which 87.5% was oil. Of these estimated proved reserves, 68.2% were proved developed reserves. As of December 31, 2014, the PV-10 and Standardized Measure of our proved reserves were $884.4 million and $672.1 million, respectively. See "Item 2. Properties—Value of Proved Reserves" for a reconciliation of PV-10 to the Standardized Measure.

Recent Developments

Convertible Notes. During the two months ended February 20, 2015, we sold $55.0 million of 13.0% convertible notes due 2017 (the "Initial Notes") in a non-brokered private placement. Subsequently, we exchanged the Initial Notes for substantially identical notes (the "Exchange Notes") issued pursuant to an indenture, dated as of February 20, 2015, between ourselves and U.S. Bank National Association, as trustee. The Exchange Notes bear interest at a rate of 13.0% per annum and mature on July 1, 2017, unless earlier redeemed or converted.

Stream Acquisition. On November 18, 2014, we closed an arrangement under British Columbia law (the "Arrangement") pursuant to an arrangement agreement (the "Arrangement Agreement") with Stream Oil & Gas Ltd. ("Stream") whereby we acquired all of the outstanding common shares of Stream in exchange for 3.2 million common shares of the Company issued at closing, and an additional 0.6 million common shares issuable if certain conditions are met. The total transaction value for the acquisition of Stream was approximately $23.9 million ($28.0 million if certain conditions are met) (at a deemed price of $7.41 per common share). Stream owns 100% of the interests in three onshore oil fields and one gas concession, consisting of one onshore gas field and one exploration license, all in Albania. We are now operating in Albania under the name TransAtlantic Albania Ltd.

Our Strengths

We believe that the following strengths provide us with meaningful competitive advantages:

Significant Exploration Acreage in Known Hydrocarbon Basins. As of December 31, 2014, we held approximately 1.8 million net acres in Turkey, Albania and Bulgaria. The majority of this acreage is exploratory, but lies within areas of known hydrocarbon production. We will seek to actively develop our acreage to monetize production, and we will consider joint ventures or farm-out agreements where appropriate.

Operations in Attractive Regions. 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. Our production in Turkey is subject to a 12.5% royalty rate, and the corporate income tax rate is 20%. We sell our oil based on Brent crude pricing, and natural gas prices are generally higher in Turkey than in North America. During 2014, we realized average prices of $83.08 per Bbl for our oil sales volumes and $8.67 per Mcf for our natural gas sales volumes in Turkey. Our production in Albania is subject to a 12% royalty rate (which includes a 10% mineral tax) until we have recovered 100% of our costs.

Growing Production and Reserves. We invested $134.8 million in exploration, development and acquisitions during 2014. Our investment resulted in a 168% increase in our proved reserves at December 31, 2014 as compared to December 31, 2013. In addition, during 2014, we increased our average daily wellhead production rate by 19.1%, as compared to 2013.

Strong and Experienced Board and Management Team. Our management team, led by our chairman and chief executive officer, Mr. Mitchell, includes executives and managers with significant industry, operational and technical experience, many of whom have an established history of working together in the industry. Mr. Mitchell previously built Riata Energy, Inc. (re-named SandRidge Energy, Inc.) into one of the largest privately-held energy companies in the United States before selling his controlling stake in 2006. In addition, we added Marlan Downey and Gregory Renwick to our board in 2013 and 2014, respectively. Mr. Downey, with over 50 years of experience in the industry, and Mr. Renwick, with over 35 years of experience in the industry, each brings significant geological and management experience to our board. In 2014, we also made significant additions to our management team, with a new president, chief operating officer and vice president of geosciences, providing a depth of exploration, acquisition, reservoir engineering, drilling and geological experience. In addition, in 2013, we added four senior technical employees who have substantial experience in geology, horizontal drilling, unconventional reservoirs and completions, and secondary recovery. On average, our technical management team possesses more than 28 years of industry experience.

Our Strategy

The following are key elements of our strategy:

Operate within Existing Cash Flows and Maintain Core Acreage. With the dramatic decline in oil prices, we are cutting our overhead and capital expenditures in an effort to operate within existing cash flow. Notwithstanding the decline in oil prices, we plan to drill at least five gross obligation wells in 2015 to hold our most promising licenses.

Increase Reserves and Production. Once oil prices stabilize and begin to recover, we plan to resume more robust investing in exploration and development to increase our oil and natural gas reserves and production in Turkey on our Arpatepe, Molla, Selmo and Thrace Basin exploration licenses and production leases, including the application of 3D seismic, horizontal drilling, fracture stimulation and enhanced oil recovery techniques. In Albania, we plan to complete the drilling and completion of the D34H1 well (the “D34H1”) and, depending upon the results, re-enter two other gas wells in the Delvina gas field. We also plan to revitalize our oilfields in Albania through well recompletions and reactivations, enlarging and lowering pumps and expanding waterfloods. We may also deepen and core several oil wells to better measure oil saturations and understand the potential of the oilfields.

Utilize New 3D Seismic Data to Improve Well Targeting. For the year ended December 31, 2014, we spent $3.7 million finalizing our 3D seismic survey over areas of Turkey where 3D seismic data did not previously exist. We received the processed data in the third quarter of 2014 and drilled several wells in the fourth quarter of 2014 based on the 3D seismic data, all resulting in successful wells, which are either producing or expected to be productive. We expect this new data will improve our ability to target well locations, drill wells and ultimately delineate hydrocarbon reservoirs.

Expand the Use of Horizontal Drilling. During 2014, we extensively used horizontal drilling techniques on our wells in the Selmo field to more effectively extract hydrocarbons and increase our returns on invested capital. We expect to continue using horizontal drilling techniques in 2015 in in the Selmo and Bahar fields.

Further Optimize Fracture Stimulation Program. In 2013 and 2014, we expanded our use of hydraulic fracturing technology to complete otherwise low porosity and permeability formations in Turkey. The evolution of fracturing fluids and stimulation designs has yielded positive results in southeastern Turkey. During 2015, we plan to continue optimizing our hydraulic fracturing techniques to improve well performance and economics.

Pursue Other Growth or Financing Opportunities. In addition to growing our reserves and production through exploration and development of our substantial acreage in Turkey and Albania, we continually evaluate acquisition, joint venture and farm-in/out opportunities. We are focused on both strengthening our positions in Turkey and Albania as well as identifying opportunities in new countries, as we did in 2014 with our acquisition of Stream.

Our Properties and Operations

Summary of Geographic Areas of Operations

The following table shows net reserves information as of December 31, 2014:

	Proved Developed Reserves (Mboe)	Proved Undeveloped Reserves (Mboe)	Total Proved Reserves (Mboe)	Probable Reserves (Mboe)	Possible Reserves (Mboe)
Turkey	8,449	8,666	17,115	15,398	24,818
Albania	13,900	1,734	15,634	13,341	12,405

Turkey

As of December 31, 2014, we held interests in 19 onshore and offshore exploration licenses and 20 onshore production leases covering a total of 1.8 million gross acres (1.1 million net acres) in Turkey. As of December 31, 2014, we had total net proved reserves of 14,406 Mbbl of oil and 16,254 Mmcf of natural gas, net probable reserves of 11,432 Mbbl of oil and 23,795 Mmcf of natural gas and net possible reserves of 12,028 Mbbl of oil and 76,739 Mmcf of natural gas in Turkey. During 2014, our average wellhead production was approximately 5,212 net Boepd of oil and natural gas in Turkey. The following summarizes our core producing properties in Turkey:

Southeastern Turkey. During 2014, substantially all of our oil production was concentrated in southeastern Turkey, primarily in the Arpatepe, Bahar, Goksu and Selmo oil fields. These fields are located southwest of the Turkish portion of the Zagros fold belt. The Zagros fold belt 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. The Selmo oil field is the second largest oil field in Turkey in terms of historical cumulative production and is responsible for the largest portion of our current crude oil production. In 2014, we drilled 12 horizontal developmental wells in the field, which had an average initial production rate of approximately 300 Bbl/d per well. We also initiated waterflood and polymer injection pilot test programs in the Selmo field in 2014. We believe secondary recovery will increase production from the field. For 2014, our net wellhead production of crude oil from the Selmo field was 1,027,639 Bbls at an average rate of approximately 2,815 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 from the Selmo oil field, which is transported by truck to their neighboring facilities. At December 31, 2014, we had 60 net producing wells in the Selmo oil field.

We hold a 100% working interest in each of our four Molla exploration licenses, which contain the Goksu and Bahar oil fields. In the Goksu field, we are primarily targeting the Mardin formation, and in the Bahar field, we are primarily targeting the Bedinan and Hazro formations. We completed shooting our 800 square kilometer Molla 3D seismic program in April 2014, and the initial phase of processed data was delivered in the third quarter of 2014. In 2014, we completed three vertical wells and one re-entry directional well in the Bahar field. For 2014, our wellhead production of crude oil from the Molla exploration licenses was 213,609 Bbls at an average rate of approximately 585 Bbl/d. At December 31, 2014, we had seven net producing wells on the Molla exploration licenses.

We hold a 50% working interest in our Arpatepe production lease and exploration license. For 2014, our wellhead production of crude oil from the Arpatepe field was 64,857 Bbls at an average rate of approximately 178 Bbl/d. In 2014, we drilled two vertical wells in the Arpatepe field, which had a gross average initial production rate of approximately 370 Bbl/d per well. At December 31, 2014, we had five gross (2.5 net) producing wells on the Arpatepe production lease.

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 near Istanbul. We have accumulated significant onshore acreage in the Thrace Basin.

Our goal is to monetize proven formations in the Thrace Basin. For 2014, our wellhead production of natural gas in the Thrace Basin was approximately 3,384 Mmcf, or approximately 9.3 Mmcf/d. In 2014, we drilled three horizontal wells and six vertical conventional wells in the Thrace Basin area. As of December 31, 2014, we had 140 gross (66.5 net) producing wells on our Thrace Basin properties, and we plan to focus on prospect and development locations in the Thrace Basin during 2015.

Bulgaria

As of December 31, 2014, we held interests in one onshore exploration concession and one onshore production concession covering a total of 567,000 acres in Bulgaria. During 2014, our wellhead production was approximately 3.3 Mmcf of natural gas on a limited test basis in Bulgaria. At December 31, 2014, we had no reserves in Bulgaria.

On November 14, 2012, Bulgaria's Council of Ministers awarded our subsidiary, Direct Petroleum Bulgaria EOOD ("Direct Bulgaria"), a 35-year production concession covering the approximately 163,000 gross acre Koynare concession area (the "Koynare Concession Area"). The Koynare Concession Area contains the Deventci-R1 well, where we discovered a natural gas 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. During 2013, our wellhead production was approximately 15.8 Mmcf of natural gas on a limited test basis, which was sold to a compressed natural gas facility adjacent to the Deventci-R1 well.

In August 2013, we entered into a farm-out agreement with Koynare Development Ltd. ("KDL"), a private oil and natural gas investment company, pursuant to which KDL would fund 75% of our initial $40 million work program in Bulgaria in exchange for a 50% interest in our Koynare Concession Area. We will also assign KDL 50% of our interest in our Stefenetz concession area, subject to LNG Energy Ltd's (now Esrey Energy) ("Esrey") farm-out interest, in the event that the pending concession application is approved by the Bulgarian government.

In January 2012, the Bulgarian Parliament enacted legislation that banned fracture stimulation in the Republic of Bulgaria. The legislation had the effect of preventing conventional drilling and completion activities. As a result, we temporarily suspended drilling and completion operations in Bulgaria in January 2012. In June 2012, the Bulgarian Parliament amended the legislation to clarify that conventional operations were not intended to be affected by the law. Accordingly, our conventional natural gas exploration, development and production activity in Bulgaria resumed in 2013. The current legislation significantly constrains our unconventional natural gas exploration, development and production activities in Bulgaria.

During the second half of 2013, we resumed drilling the Deventci-R2 directional well on our Koynare Concession Area. In January 2014, we reached target depth of 14,100 feet on the Deventci-R2 well and conducted a long-term pressure build-up test on the well during the second quarter of 2014 to evaluate the well's connectivity to the reservoir following an initial production test of approximately 2.0 Mmcf/d of natural gas with condensates. In the fourth quarter of 2014, we received approval from the Bulgarian government to acidize the well. We conducted initial stimulation in December 2014 to enhance the well's productivity and are currently evaluating the results of the stimulation.

In November 2011, we initiated the application process for a production concession covering approximately 395,000 gross acres over the southern portion of our former A-Lovech exploration permit (the "Stefenetz Concession Area"). The Stefenetz Concession Area is estimated to contain over 300,000 prospective acres of Etropole shale at a depth of approximately 12,500 feet, which the Bulgarian government has certified as a geologic discovery. During 2012, we initiated an environmental impact assessment which the Bulgarian government must approve prior to granting the production concession. We applied for a commercial discovery in the fourth quarter of 2011 for the Peshtene R-11 well. The Ministry of Economy and Energy rejected our application in July 2014. We appealed the decision in accordance with Bulgarian law and are awaiting a decision from the Ministry of Economy and Energy. Pursuant to our agreement with Esrey, if we obtain a production concession over the Stefenetz Concession Area, Esrey would fund an additional $12.5 million in exchange for a 50% working interest in the production concession. The remaining 50% working interest in the production concession would be split equally between us and KDL.

Albania

We own 100% of the interests in three onshore oil fields and one gas concession consisting of one onshore gas field and one exploration license in Albania. As of December 31, 2014, we had total net proved reserves of 14,259 Mbbl of oil and 8,249 Mmcf of natural gas, net probable reserves of 10,014 Mbbl of oil and 19,963 Mmcf of natural gas and net possible reserves of 7,152 Mbbl of oil and 31,518 Mmcf of natural gas in Albania. During 2014, we had net production (before mineral taxes) of 842 Bbl/d of oil and no natural gas. The following summarizes our core producing properties in Albania:

Ballsh-Hekal. We have taken over 23 wells (of which 13 are producing) from Albpetrol Sh.A ("Albpetrol") in the Ballsh-Hekal field. We believe that a significant number of these wells did not penetrate the entire hydrocarbon column. Albpetrol still operates approximately 60 wells in the field. We have the right to take over the remaining wells at our option, which we expect to do in 2015. During 2014, our net production (before mineral taxes) was 86 Bbl/d of oil from the field.

Cakran-Mollaj. We have taken over 70 wells (of which approximately 30 are producing) from Albpetrol in the Cakran-Mollaj field. We believe that a significant number of these wells did not penetrate the entire hydrocarbon column. During 2014, our net production (before mineral taxes) was approximately 307 Bbl/d of oil from this field. We are working on improving the reliability of surface equipment in this field prior to reactivating and recompleting additional wells.

Gorisht-Kocul. We have taken over all 295 wells (of which approximately half are producing) in the Gorisht-Kocul field from Albpetrol. We believe that a significant number of these wells did not penetrate the entire hydrocarbon column. During 2014, our net production (before mineral taxes) from this field was 449 Bbl/d of oil. We are in the process of conducting two waterflood projects in this reservoir, which have mitigated the natural pressure and production decline in portions of this field. In addition, we intend to workover and reactivate existing wells with modern rod pumps and progressive cavity pumps.

Delvina Concession. We own the Delvina Concession, which is comprised of the partially-developed Delvina field and the Delvina exploration block.

Delvina Field. The Delvina natural gas field has two previously producing vertical wells, the Delvina D4 and D12 wells. During the workover of the Delvina D12 well in 2013, after successful stimulation and flow tests, Stream encountered an obstruction in the completion string that could not be removed through solvent injection and was planning further workover procedures. We plan to bring the Delvina D4 well back online following workover of the well. In April 2014, Stream spud the D34H1 well in the Delvina field, reaching a depth of approximately 750 meters before temporarily abandoning drilling due to a lack of funds. Drilling operations on the D34H1 well will resume during the first half of 2015. The Delvina natural gas field is connected to potential markets by an existing pipeline, including to a local thermal power plant, but needs additional downstream capacity.

Delvina Block. Under the Delvina License Agreement and Petroleum Agreement, we have the right to develop approximately 60,000 acres adjacent to the Delvina natural gas field, referred to as the Delvina Block. The Delvina Block offers significant exploration potential.

Current Operations

As of March 1, 2015, our net wellhead production in Turkey was an aggregate of approximately 4,164 Bbl/d, primarily from the Selmo production lease, Arpatepe production lease and Molla exploration licenses, and approximately 7.1 Mmcf/d of natural gas, primarily from our various Thrace Basin production leases and exploration licenses. As of March 1, 2015, our net production (before mineral taxes) in Albania was an aggregate of approximately 652 Bbl/d. The following describes our current operations by country:

Turkey. We are not engaging in any new drilling activities in Turkey during the first quarter of 2015.

Bulgaria. In the fourth quarter of 2014, we received approval from the Bulgarian government to acidize the Deventci-R2 well on the Koynare Concession Area. We conducted initial stimulation in December 2014 to enhance the well's productivity and are currently evaluating the results of the stimulation.

Albania. We plan to resume drilling the D34H1 well during the first half of 2015.

Planned Operations

We expect our net field capital expenditures for 2015 to range between $12.0 and $38.0 million. We expect net field capital expenditures during 2015 include approximately $12.0 million of drilling and completion expense for five gross obligation wells to hold our most promising licenses in Turkey. We expect cash on hand, proceeds from the sale of our convertible notes, and cash flow from operations will be sufficient to fund our 2015 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2015 capital expenditure budget is subject to change.

Exploration, Development and Production. We currently plan to execute the following drilling and exploration activities during 2015:

Turkey. We plan to drill five gross license obligations wells. Depending upon oil pricing, we may resume drilling in our Molla area or the Selmo field. We also plan to complete the Pinar-1 and Ebiyat-2 wells during the first half of 2015.

Bulgaria. We plan to evaluate additional completion activities on the Deventci-R2 well.

Albania. We plan to resume drilling the D34H1 well during the first half of 2015.

Principal Markets

In accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 280, Segment Reporting ("ASC 280"), we currently have three reportable geographic segments: Turkey, Albania and Bulgaria. For financial information about our operating segments and geographic areas, refer to "Note 12—Segment information" to our consolidated financial statements.

Customers

Oil. During 2014, 78.6% of our oil production was concentrated in the Selmo field in Turkey. TUPRAS purchases the majority of our oil production from the Selmo field. During 2014, we sold $102.8 million of oil to TUPRAS, representing approximately 73.0% of our total revenues. We sell our 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 Boru Hatlari ile Petrol Tasima A.S. ("BOTAŞ") Batman tanks and to the 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. No other purchasers of our oil accounted for more than 10% of our total revenues.

Natural Gas. During 2014, no purchasers of our natural gas 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 substantial number of other companies, including U.S.-based and international 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 each of the following areas:

- seeking oil and natural gas exploration licenses and production licenses and leases;
- acquiring desirable producing properties or new leases for future exploration;
- marketing oil and natural gas production;
- integrating new technologies; and
- contracting for drilling services and equipment and securing the expertise necessary to develop and operate properties.

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, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We have successfully utilized fracture stimulation in our Thrace Basin, Molla and Selmo licenses and production leases.

For unconventional reservoirs, including the Mezardere formation in the Thrace Basin, a typical fracture stimulation consists of injecting between 20,000 and 100,000 gallons of fluid that contain between 10,000 and 150,000 pounds of sand. Fluids vary depending on formation and treatment objective but, in general, are either slickwater (fresh water with salt and friction reducer) or a gelled fluid containing organic polymers with a 4% potassium chloride solution and required breakers. Fracture stimulations in Selmo and Molla are conducted in a low permeability carbonate reservoir. These stimulations generally consist of injecting between 20,000 and 100,000 gallons of fluid that contain between 10,000 and 100,000 pounds of sand. Fluids are generally a mixture of slickwater and 15% hydrochloric acid, which is typical in carbonate stimulation. The size of fracture stimulation treatments is dependent on net pay thickness and the proximity of the hydrocarbon zones of interest to water bearing zones.

Although the cost of each well will vary, on average approximately 30% of the total cost of drilling and completing a well in the unconventional Mezardere formation in the Thrace Basin and approximately 15% of the total cost of completing a well at Selmo is associated with fracture stimulation activities. We account for these costs as typical drilling and completion costs and include them in our capital expenditure budget.

We believe that the stacked nature of the sandstone intervals within the Mezardere unconventional formation, which is up to approximately 5,300 feet thick, and the limited number of deep penetrations to date on these structures provides significant opportunities for additional drilling and multi-stage fracs as the program matures.

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 into the surface casing 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. 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 our fracture stimulation program in 2015. We also employ procedures for environmentally friendly disposal of fluids recovered from fracture stimulation, including recycling approximately 50% of these fluids.

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 Regulation. 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 and the temporary suspension of unconventional exploration and drilling activities imposed in Romania in 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 restrictions on the repatriation of earnings or capital to foreign entities from Turkey, Albania or Bulgaria. However, there can be no assurance that any such restrictions 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.

There has been a recent surge 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. In 2012, the Romanian government temporarily suspended unconventional drilling and exploration of hydrocarbons, including fracture stimulation, pending a government review of unconventional drilling and completion techniques. As a result of the suspension, we relinquished our Sud Craiova license in Romania. There is a risk that Turkey or Albania could at some point impose similar legislation or regulations. Such legislation or regulations could severely impact our ability to drill and complete wells, and could increase the cost of planning, designing, drilling, completing and operating wells. We are committed to complying with legislation and regulations involving fracture stimulation 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.

Insurance

We currently carry general liability insurance and excess liability insurance, including pollution insurance, with a combined annual limit of $22.0 million per occurrence and $24.0 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 $15.0 million and is subject to deductibles ranging from $150,000 to $500,000 per occurrence.

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, 2014, we employed 719 people. Approximately 40 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”). Approximately 35 of our employees at another of our subsidiaries operating in Turkey were represented by a separate collective bargaining agreement with 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.

Executive Officers of the Registrant

The following table and text sets forth certain information with respect to our executive officers as of March 1, 2015:

Name	Age	Positions
N. Malone Mitchell 3rd	53	Chairman and Chief Executive Officer
Todd C. Dutton	61	President
James R. Huling	52	Chief Operating Officer
Wil F. Saqueton	45	Vice President and Chief Financial Officer
Matthew W. McCann	46	General Counsel and Corporate Secretary
Harold “Lee” Muncy	62	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, 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.

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 the Company's chairman and chief executive officer, N. Malone Mitchell 3rd and his family, since January 2007, where his primary responsibility is to originate and develop oil and natural gas projects. He brings 37 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.

James R. Huling has served as the Company’s chief operating officer since May 2014. He has also served as chief operating officer of Longfellow since May 2012. From 2007 until May 2012, Mr. Huling served as president of Kiamichi Energy Corporation, a Fort Worth, Texas-based consulting and production company that he founded. He brings nearly 30 years of experience in reservoir engineering, drilling, and completion operations and production optimization. Mr. Huling began his career with Kerr-McGee Corporation and subsequently held engineering and operational roles with Encore Acquisition Company, Riata Energy, Inc. and Ovation Energy Partners before founding Kiamichi Energy Corporation.

Wil F. Saqueton has served as the Company’s vice president and chief financial officer since August 2011. Mr. Saqueton previously served as the Company’s corporate controller from May 2011 until August 2011 and as a consultant to the Company from February 2011 until May 2011. Prior to joining the Company, Mr. Saqueton served as the vice president and chief financial officer of BCSW, LLC, the owner of Just Brakes in Dallas, Texas, from July 2006 to December 2010. From July 1995 until July 2006, he held a variety of positions at Intel Corporation, including strategic controller at the Chipset Group, operations controller at the Americas Sales and Marketing Organization Division, finance manager at the Intel Online Services, Inc. Division and senior financial analyst at the Chipset Group. Prior to 1995, Mr. Saqueton was a senior associate at Price Waterhouse, LP.

Matthew W. McCann has served as the Company’s general counsel and corporate secretary since August 6, 2014. Mr. McCann also has served as counsel for Riata Corporate Group, LLC and business development specialist for Longfellow since 2011 and from 2007 to 2009. From 2009 to 2011, Mr. McCann served as chief executive officer of the Company. Prior to joining Riata Corporate Group and Longfellow, he served as senior vice president, legal and corporate secretary for SandRidge Energy, Inc. Mr. McCann began his legal career at Sprouse Shrader Smith PLLC in Amarillo, Texas.

Harold “Lee” Muncy has served as the Company’s 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 35 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

A decline in oil and natural gas prices may adversely affect our results of operations, financial condition or ability to meet our capital expenditure obligations and financial commitments.

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, oil and natural gas. Oil prices have declined substantially in recent months and may remain at or below current levels in the near future. The market price of Brent crude oil has decreased approximately 50% since June 2014 as a result of market uncertainties over the supply and demand of oil due to increased production in certain regions, decisions made by OPEC, the current state of the global economy and concerns over future global oil demand. Lower oil and natural gas prices, such as the recent substantial decline in oil prices, may reduce the amount of oil and natural gas that we can produce economically, make some wells uneconomical to drill or operate, reduce our ability to develop our properties, reduce our ability to offset the natural decline in production from producing wells through new development and result in lower reserves. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future.

A decrease in oil or natural gas prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the value of these assets. The recent substantial decline in oil prices may adversely impact the ultimate development of the quantity of reserves that we reported at December 31, 2014. If oil or natural gas prices continue to decline in the future, we might not be able to generate sufficient cash flow from operations to meet our obligations and make planned capital expenditures. Oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. Among the factors that could cause fluctuations are:

- market expectations regarding supply and demand for oil and natural gas;
- decreased demand due to weak global economic growth;
- levels of production and other activities of the Organization of Petroleum Exporting Countries and other oil and natural gas producing nations;
- market expectations about future prices;
- the level of global oil and natural gas exploration, production activity and inventories;
- political conditions, including embargoes, in or affecting oil and natural gas production activities;
- increased production due to new extraction developments and improved extraction and production methods; and
- the price and availability of alternative fuels.

Our businesses, results of operations, future rate of growth and quantities of reserves that are commercially recoverable depend heavily on the prices we receive for oil sales. Oil prices also affect our cash flows available for capital expenditure obligations and financial commitments. No assurance can be given that future oil prices will be at levels which enable us to do business profitably or at levels that make it economically viable to produce from certain wells. A decline in oil or natural gas prices may have a material adverse effect on our business, financial condition and results of operations.

We may be required to write down the carrying values of our oil and natural gas properties.

Oil prices have declined substantially in recent months and may remain at or below current levels in the near future. There is a risk that due to the recent decline in oil prices or future declines in oil prices, we could be required to write down the carrying value of our oil and natural gas properties, which would reduce our earnings and shareholders' equity. We follow the successful efforts method of accounting for our oil and natural gas properties. Under this method, the costs of productive wells, developmental dry holes and productive leases are capitalized. 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. 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 capitalized costs of our oil and natural gas properties may not exceed their estimated fair market value. When evaluating our proved properties, we are required to test for potential write-downs at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets, which is typically on a field-by-field basis. If capitalized costs exceed future cash flows, we write down the costs of proved properties to our estimate of fair market value, which is generally estimated using a discounted cash flow approach. When evaluating our unproved properties, we write down the capitalized costs of the unproved properties if it is determined that the costs are not likely to be recoverable. Any such charge will not affect our cash flow from operating activities, but will reduce our earnings and shareholders' equity.

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

We have incurred substantial losses in prior years. During 2014, we generated net income from continuing operations of $29.1 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 risks described herein, unforeseen expenses, difficulties, complications and delays, and other unknown risks.

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

The future performance of our business will depend upon our ability to identify, acquire and develop additional oil and natural gas reserves that are economically recoverable. Success will depend 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 future 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.

Shortages of drilling rigs, equipment, oilfield services and qualified personnel could delay our exploration and development activities and increase the prices we pay to obtain such drilling rigs, equipment, oilfield services and personnel.

Our industry is cyclical and, from time to time, there may be a shortage of drilling rigs, equipment, oilfield services and qualified personnel in the countries in which we operate. Shortages of drilling and workover rigs, pipe and other equipment may occur as demand for drilling rigs and equipment increases, along with increases in the number of wells being drilled. These factors can also cause significant increases in costs for equipment, oilfield services and qualified personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly increase our net loss, decrease our cash provided by operating activities, or restrict our ability to conduct the exploration and development activities we currently have planned and budgeted or which we may plan in the future. In addition, the availability of drilling rigs can vary significantly from region to region at any particular time. An undersupply of rigs in any of the regions where we operate may result in drilling delays and higher drilling costs for the rigs that are available in that region.

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.

The majority 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 purchases all of our oil production from Turkey, representing 72.0% of our total revenues in 2014. 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. 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.

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, 2014, of our total net undeveloped acreage, 24.0% and 22.6% will expire during 2015 and 2016, 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.

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We could lose permits or licenses on certain of our properties in Albania unless we address non-compliance with the terms of such permits or licenses.

We are currently not in compliance with certain terms of certain of our permits or licenses in Albania. We are working with the Albanian government to resolve the payment of amounts due to Albpetrol and compliance with the terms of certain of our licenses in Albania. If we are unsuccessful in resolving these issues, Albpetrol could take steps to terminate some or all of the licenses.

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

Virtually all of our international operations are performed in the emerging markets of Turkey, Bulgaria and Albania, which may expose us to greater risks than those associated with more developed 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, 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 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 southeastern Turkey and nearby countries could adversely affect our business.

During 2014, we derived 78.6% of our oil production from the Selmo oil field in southeastern Turkey. Historically, the southeastern area of Turkey and nearby countries such as Iran, Iraq and Syria have experienced political, social, security and economic problems, terrorist attacks, insurgencies, war and civil unrest. Since December 2010, political instability has increased markedly 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 and more can be expected to cross the border as the conflict continues. Moreover, tensions between Turkey and Syria have escalated.

The current conflict with the terrorist group Islamic State in Iraq and Syria ("ISIS"), as well as tension in and involving the Kurdish regions of northern Iraq, which are contiguous to the region where our southeast Turkey licenses are located, may have political, social or security implications in Turkey or otherwise have a negative impact on the Turkish economy. Stability and security in Iraq deteriorated significantly in 2014 due to the conflict with ISIS.

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. Despite these precautions, the safety of our personnel and operations in these locations may continue to be at risk, and we may in the future suffer the loss of employees and contractors or our operations could be disrupted, any of which could have a material adverse effect on our business and results of operations.

The Stream acquisition involves risks associated with acquisitions and integrating acquired businesses, including the potential exposure to significant liabilities, and the intended benefits of the Stream acquisition may not be realized.

The Stream acquisition involves risks associated with acquisitions and integrating acquired businesses into existing operations, including:

- the risks of entering into markets in which we have no prior experience;
- our estimates regarding reserves and production resulting from the Stream acquisition may prove to be incorrect;
- our senior management's attention may be diverted from the management of daily operations to the integration of Stream;
- we could incur significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;
- difficulties in assimilating and integrating the internal controls, technologies and personnel acquired;
- the properties acquired in the Stream acquisition may not perform as well as we anticipate; and
- unexpected costs, delays and challenges may arise in integrating Stream.

Even if we successfully integrate Stream into our operations, it may not be possible to realize the full benefits we anticipate or we may not realize these benefits within the expected timeframe. If we fail to realize the benefits we anticipate from the Stream acquisition, our business, results of operations and financial condition may be adversely affected.

Our failure to successfully integrate Stream's business could negatively impact our future business and financial results

Our failure to successfully integrate Stream's business could negatively impact our future business and financial results. Our acquisition of Stream represents an expansion of our operations into a new geographic area in an international market, with operating conditions and a regulatory environment that may not be as familiar to us as our existing core operating areas. Our success in operating in Albania will depend, in part, on our ability to realize benefits from integrating Stream's business with our existing businesses. The integration process may be complex, costly and time-consuming. To realize such benefits, we must successfully combine the businesses in an efficient and effective manner. If we are not able to achieve these objectives within the anticipated time frame, or at all, any benefits related to our acquisition of Stream may not be realized fully, or at all, or may take longer to realize than expected.

Successful integration will require, among other things, combining the companies':

- accounting;
- information technology;

- internal control over financial reporting;
- disclosure controls;
- key personnel;
- geographically separate facilities; and
- businesses and executive cultures.

We may not accomplish this integration successfully and may not realize the benefits contemplated by combining the operations of the Company and Stream.

Our senior credit facility and term loan facility contain various restrictive covenants that limit our management's discretion in the operation of our business and could lead to an event of default that may adversely affect our business, financial condition and results of operations.

The operating and financial restrictions and covenants in our senior credit facility (the "Senior Credit Facility") with BNP Paribas (Suisse) SA ("BNP Paribas") and the International Finance Corporation ("IFC"), and in our term loan facility (the "Term Loan Facility") with Raiffeisen Bank Sh.A ("Raiffeisen"), may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Our Senior Credit Facility contains various covenants that restrict our ability to, among other things:

- incur additional debt;
- create liens;
- enter into any hedge agreement for speculative purposes;
- engage in business other than as an oil and natural gas exploration and production company;
- enter into sale and leaseback transactions;
- enter into any merger, consolidation or amalgamation;
- declare or provide for any dividends or other payments or distributions;
- redeem or purchase any shares; or
- guarantee the obligations of any other person.

In addition, the Senior Credit Facility requires us to maintain specified financial ratios and tests. Various risks, uncertainties and events beyond our control could affect our ability to comply with the covenants and financial tests and ratios required by the Senior Credit Facility and could result in an event of default under the Senior Credit Facility.

An event of default under the Senior Credit Facility includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control is an event of default. A change of control is defined as the occurrence of any of the following: (i) our failure to own, of record and beneficially, all of the equity of TransAtlantic Exploration Mediterranean International Pty Ltd ("TEMI"), Talon Exploration, Ltd. ("Talon Exploration"), TransAtlantic Turkey, Amity Oil International Pty. Ltd. ("Amity"), Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş. ("Petrogas"), and DMLP, Ltd. ("DMLP," and together with TEMI, Talon Exploration, TransAtlantic Turkey, Amity and Petrogas, the "Borrowers") or either of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide, Ltd. ("TransAtlantic Worldwide") or to exercise, directly or indirectly, day-to-day management and operational control of any Borrower or TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide; (ii) the failure by the Borrowers to own or hold, directly or indirectly, all of the interests granted to Borrowers pursuant to certain hydrocarbon licenses designated in the Senior Credit Facility; or (iii) (a) Mr. Mitchell ceases for any reason to be the executive chairman of our board of directors at any time, (b) Mr. Mitchell and certain of his affiliates cease to own of record and beneficially at least 35% of our common shares; or (c) any person or group, excluding Mr. Mitchell and certain of his affiliates, shall become, or obtain rights to become, the beneficial owner, directly or indirectly, of more than 35% of our outstanding common shares entitled to vote for members of our board of directors on a fully-diluted basis; provided that, if Mr. Mitchell ceases to be executive chairman of our board of directors by reason of his death or disability, such event shall not constitute an event of default unless we have not appointed a successor reasonably acceptable to the lenders within 60 days of the occurrence of such event.

In the event of a default and acceleration of indebtedness under the Senior Credit Facility, our business, financial condition and results of operations may be materially and adversely affected.

Pursuant to the terms of the Term Loan Facility, until amounts under the Term Loan Facility are repaid, Stream Oil & Gas Ltd., a Cayman Islands corporation (“Stream Sub”), may not, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of Stream Sub to create any liens, (iii) enter into any amalgamation, demerger, merger, or corporate reconstruction or any joint venture or partnership agreement, (iv) incorporate any company as a subsidiary, (v) dispose of any asset, (vi) declare or pay any dividends to shareholders, (vii) enter into a sale and leaseback arrangement, (viii) make any substantial change to the general nature or scope of its business from that carried on at the date of the Term Loan Facility, (ix) use, deposit, handle, store produce, release or dispose of dangerous materials, (x) make any loans or grant any credit, and (xi) cancel, terminate amend or waive any default under any export contract or allow any buyer to do the same.

In addition, the Term Loan Facility contains financial covenants that require Stream Sub to maintain as of the end of each fiscal year: (i) earnings before interest, taxes, depreciation and amortization ("EBITDA") of not less than $10.0 million; (ii) an outstanding loan principal of no more than twice its EBITDA; and (iii) EBITDA of at least ten times greater than its accrued interest, commission, fees, discounts, prepayment fees, premiums, charges and other finance payments.

An event of default under the Term Loan Facility, includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, upon the occurrence of a change of control of Stream Sub, Stream Sub is required to notify Raiffeisen, and Raiffeisen would have the option to cancel loan commitments and accelerate all outstanding loans and other amounts payable. A change of control is defined under the Term Loan Facility as Stream ceasing to hold more than 75% of the shares in the issued share capital of Stream Sub carrying the right to vote. Our acquisition of Stream did not constitute a change of control under the Term Loan Facility.

Stream must, upon the request of Raiffeisen when Stream Sub's predicted expenditures exceed its predicted revenues for any period, inject cash into Stream by means of equity loan or other method acceptable to Raiffeisen to the extent necessary to remedy the cashflow shortfall or repay the total amount outstanding under the Term Loan Facility.

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

As of December 31, 2014, approximately 40 of our employees at one of our subsidiaries operating in Turkey were represented by collective bargaining agreements with PETROL-IS. We are currently negotiating a collective bargaining agreement with PETROL-IS covering approximately 35 employees at another of our subsidiaries operating in Turkey. Potential work disruptions from labor disputes with these employees could disrupt our business and adversely affect our financial condition and results of operations.

We could be assessed for Canadian federal tax as a result of our 2009 continuance under the Bermuda Companies Act 1981.

For Canadian tax purposes, we were deemed, immediately before the completion of our 2009 continuance under the Bermuda Companies Act 1981, to have disposed of each property owned by us for proceeds equal to the fair market value of that property, and will be subject to tax on any resulting net income. In addition, we were required to pay a special "branch tax" equal to 25% of any excess of the fair market value of our property over the "paid-up capital" (as defined in the Income Tax Act (Canada)) of our outstanding common shares and our liabilities. However, management, together with its professional advisors, has determined that the paid-up capital of our common shares and our liabilities exceeded the fair market value of our property, resulting in no "branch tax" being payable. The Canada Revenue Agency ("CRA") may not accept our determination of the fair market value of our property. In the event that CRA's determination of fair market value is significantly higher than our valuation and such determination is final, we may be subject to material amounts of tax resulting from the deemed disposition.

Risks Related to the Oil and Natural Gas Industry

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

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.

We may not correctly evaluate reserves data or the exploitation potential of properties as we engage in our acquisition, development, and exploitation activities.

Our future success will depend on the success of our acquisition, development, and exploitation activities. Our decisions to purchase, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Our estimates regarding reserves and production resulting from the acquisitions of TEMI, Talon Exploration, Amity, Petrogas, Direct Bulgaria, Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") and Stream, and our exploration and development activities may prove to be incorrect, which could significantly reduce our income and our ability to generate cash needed to fund our capital program and other working capital requirements in the longer term.

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 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.

A substantial or extended decline in oil and natural gas prices may adversely affect our ability to meet our capital expenditure obligations and financial commitments, including debt service.

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, oil and natural gas. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Historically, oil and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future.

A decrease in the price of oil and natural gas may mean that we are not able to generate sufficient cash flow to meet our debt service payments, which could lead to a default under these agreements.

A decrease in oil or natural gas prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the value of these assets. If oil or natural gas prices decline significantly for extended periods of time in the future, we might not be able to generate sufficient cash flow from operations to meet our obligations and make planned capital expenditures. Oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. Among the factors that could cause fluctuations are:

- market expectations regarding supply and demand for oil and natural gas;

- levels of production and other activities of the Organization of Petroleum Exporting Countries and other oil and natural gas producing nations;
- market expectations about future prices;
- the level of global oil and natural gas exploration, production activity and inventories;
- political conditions, including embargoes, in or affecting oil and natural gas production activities; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural gas prices may have a material adverse effect on our business, financial condition and results of operations.

If oil and natural gas prices decline, we may be required to write down the carrying values of our oil and natural gas properties.

There is a risk that we could be required to write down the carrying value of our oil and natural gas properties, which would reduce our earnings and shareholders’ equity. We follow the successful efforts method of accounting for our oil and natural gas properties. Under this method, the costs of productive wells, developmental dry holes and productive leases are capitalized. 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. 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 capitalized costs of our oil and natural gas properties may not exceed their estimated fair market value. When evaluating our proved properties, we are required to test for potential write-downs at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets, which is typically on a field-by-field basis. If capitalized costs exceed future cash flows, we write down the costs of proved properties to our estimate of fair market value, which is generally estimated using a discounted cash flow approach. When evaluating our unproved properties, we write down the capitalized costs of the unproved properties if it is determined that the costs are not likely to be recoverable. Any such charge will not affect our cash flow from operating activities, but will reduce our earnings and shareholders’ equity.

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.

At December 31, 2014, approximately 31.8% of our total estimated net proved reserves were proved undeveloped reserves. Undeveloped reserves, by their nature, are significantly less certain than developed reserves. At December 31, 2014, 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 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.

Part of our strategy involves drilling in new or emerging unconventional formations using fracture stimulation and horizontal drilling and completion techniques. The results of our drilling program in these formations may be subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production.

The results of our drilling in new or emerging unconventional formations, such as the Mezardere formation, are generally more uncertain than drilling results in areas that are developed and have established production. Because new or emerging formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Further, part of our drilling strategy to maximize recoveries from our properties in Turkey, particularly in southeastern Turkey, involves the drilling of horizontal wells. Our experience with horizontal drilling in southeastern Turkey, as well as the industry’s drilling and production history, while growing, is limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established. Further, the utilization of these techniques requires substantially greater capital expenditures, as compared to the drilling of a traditional vertical well. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, and/or natural gas and oil prices decline, our investment in these areas may not be as attractive as we anticipate and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

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, sand and chemicals into rock formations 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. Our costs to comply with these numerous laws, regulations, licenses and permits are significant.

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.

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.

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 substantial 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 each of the following areas:

- seeking oil and natural gas exploration licenses and production licenses;

- acquiring desirable producing properties or new leases for future exploration;
- marketing oil and natural gas production;
- integrating new technologies; and
- contracting for drilling services and equipment and securing the expertise necessary to develop and operate properties.

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.

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.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions 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.

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 1, 2015, Mr. Mitchell beneficially owned approximately 36% of our outstanding common 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 our 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 our interests or the interests of our other shareholders.

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, Albania, 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;
- our liquidity; and
- our ability to raise additional funds.

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.

Risks Related to Our Indebtedness

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

We have a significant amount of indebtedness. Our substantial 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 our future operating performance, which will be affected by prevailing economic conditions and financial, business and other factors affecting our company and industry, many of which are beyond our control.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Turkey

General. As of December 31, 2014, we held interests in 19 onshore and offshore exploration licenses and 20 onshore production leases covering a total of approximately 1.8 million gross acres (approximately 1.1 million net acres) in Turkey. We acquired our interests in Turkey through acquisitions, as well as through farm-in agreements with existing third-party license holders and through applications submitted to the Turkish General Directorate for Petroleum Affairs (the “GDPA”), 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, 2014, we had total net proved reserves of 14,406 Mbbl of oil and 16,254 Mmcf of natural gas, net probable reserves of 11,432 Mbbl of oil and 23,794 Mmcf of natural gas and net possible reserves of 12,028 Mbbl of oil and 76,739 Mmcf of natural gas in Turkey.

Equipment Yards. As of December 31, 2014, we leased equipment yards in Muratli, Diyarbakir and Tekirdag and owned equipment yards at Selmo and 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% and the corporate income tax rate is 20%. Our revenue from the Selmo oil field is subject to an additional 10% royalty, which is offset by the amount of exploration expense that TEMI and DMLP, the owners of our interest in the Selmo oil field, incur in Turkey. If those exploration expenses do not equal or exceed the amount of this additional 10% royalty, we would owe the difference. 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 GDPA. 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. Further details regarding the timing for conversion are awaiting confirmation from the GDPA.

The GDPA 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. The term of a lease is for 20 years and may be extended for two further terms of 10 years each. 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 20 years plus two further 10 year extensions if production is maintained. We have applied to the GDPA to convert some of our qualifying acreage into the new petroleum law regulations. This will be a gradual process, but we anticipate that conversion into the new petroleum law will provide for the renewal of the exploration license terms for qualifying acreage.

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Northwestern Turkey. The following map shows our interests in northwestern Turkey at December 31, 2014:

Adatepe (Production Lease 4959 and License 5016). We own a 50% working interest in Production Lease 4959 and License 5016, which cover approximately 3,086 gross acres and 117,000 gross acres, respectively. As of December 31, 2014, we had seven gross (3.5 net) producing wells on the Adatepe production lease. In 2015, we plan to drill one well on License 5016 or License 4288 to satisfy the work program for License 5016, and we plan to maintain production to satisfy our obligation on Production Lease 4959. We are the operator of Production Lease 4959 and License 5016. The current terms of Production Lease 4959 and License 5016 expire in September 2031 and January 2016, respectively, with extensions available under the old and new petroleum laws.

Alpullu (Production Lease 4794) and Temrez (License 4861). We own a 100% working interest in Production Lease 4794 and License 4861, which cover approximately 3,158 acres and 117,000 acres, respectively. As of December 31, 2014, we had six gross and net producing wells on the Alpullu production lease. One well on License 4861 is currently awaiting completion. We plan to maintain production to satisfy our obligation on Production Lease 4794. We are the operator of Production Lease 4794 and License 4861, which expire in September 2028 and December 2014, respectively, with extensions available under the old and new petroleum laws. We applied to convert License 4861 to the new petroleum law for a new five-year term in the second quarter of 2014, and are awaiting GDPA approval.

Atakoy (Production Lease 5122). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 5122, which covers approximately 440 gross acres. As of December 31, 2014, we had ten gross (4.15 net) producing wells on the Atakoy production lease. We plan to maintain production to satisfy our obligation on Production Lease 5122. We are the operator of Production Lease 5122, which expires in November 2032, with extensions available under the old and new petroleum laws.

Banarli (Production Lease 5059). We own a 50% working interest in Production Lease 5059, which covers approximately 4,608 gross acres. As of December 31, 2014, we had one gross (0.5 net) producing well on the Banarli production lease. We plan to maintain production to satisfy our obligation on Production Lease 5059. We are the operator of Production Lease 5059, which expires in February 2032, with extensions available under the old and new petroleum laws.

Bekirler (License 4126). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 4126, which covers approximately 124,000 gross acres. We are the operator of License 4126, which expires in December 2015.

Dogu Adatepe (Production Lease F19-b4-1). We own a 50% working interest in the Dogu Adatepe Production Lease, which covers part of our former Cayirdere license. The lease covers approximately 4,000 gross acres and expires in October 2017, subject to an additional 28 years of extensions under the new petroleum law available with the maintenance of production on the production lease.

Edirne (Production Leases) and Habiller (License 4037). We own a 55% working interest in three Edirne Production Leases and a 100% working interest in License 4037, which cover an aggregate of approximately 239,000 gross acres. In April 2010, we commenced natural gas sales from the Edirne natural gas field. As of December 31, 2014, we had 11 gross (6.1 net) producing wells on the Edirne and Habiller licenses. We are the operator of the Edirne Production Leases and License 4037, which expire in 2034 and March 2016, respectively, with extensions available under the old and new petroleum laws.

Gelindere (Production Lease 3659). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 3659, which covers approximately 709 gross acres. As of December 31, 2014, we had one gross (0.4 net) producing well on the Gelindere lease. We plan to maintain production to satisfy our obligation on Production Lease 3659. We are the operator of Production Lease 3659, which expires in June 2017, with extensions available under the old and new petroleum laws.

Gocerler (Production Lease 4200 and License 4288). We own a 50% working interest in Production Lease 4200 and License 4288, which cover approximately 3,363 gross acres and 119,000 gross acres, respectively. As of December 31, 2014, we had four producing wells on the Gocerler production lease and nine gross (4.5 net) producing wells on License 4288. We plan to drill one well in 2015 on License 4288 or License 5016 to satisfy the work program for License 4288 and we plan to maintain production to satisfy our obligations on Production Lease 4200. We are the operator of Production Lease 4200 and License 4288, which expire in May 2023 and August 2015, respectively, with extensions available under the old and new petroleum laws.

Hayrabolu (Production Lease 2926). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Lease 2926, which covers approximately 12,400 gross acres. As of December 31, 2014, we had four gross (1.7 net) producing wells on the Hayrabolu production lease. We plan to maintain production to satisfy our obligation on Production Lease 2926. We are the operator of Production Lease 2926, which expires in February 2020, with one ten-year extension available under the old and new petroleum laws.

Karaevli (License 3934 and Karaevli Production Lease). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3934 and the Karaevli Production Lease, which cover approximately 122,000 gross acres. As of December 31, 2014, we had three gross (1.3 net) producing wells on the Karaevli license. We are the operator of License 3934 and the Karaevli Production Lease, which expire in November 2015 and April 2019, respectively, with extensions available under the old and new petroleum laws.

Karanfiltepe (License 5151). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 5151, which covers approximately 121,000 gross acres. As of December 31, 2014, we had two gross (0.8 net) producing wells on the Karanfiltepe license. We are the operator of the Karanfiltepe license, which expires in June 2017, with extensions available under the old and new petroleum laws. We applied for conversion of this license to the new petroleum law in the second quarter of 2014, and are awaiting GDPA approval.

Malkara (License 4532). We own a 100% working interest in License 4532, which covers approximately 122,000 acres. We are the operator of License 4532, which expires in January 2015, with extensions available under the old and new petroleum laws. We applied for conversion of this license to the new petroleum law in the second quarter of 2014, and are awaiting GDPA approval.

Osmanli (License 3931 and Osmanli Production Leases). We own 41.5%, subject to a 0.415% overriding royalty interest, in License 3931 and the three Osmanli Production Leases, which cover approximately 118,000 gross acres. As of December 31, 2014, we had 53 gross (22.0 net) producing wells on the Osmanli license and Osmanli Production Leases. License 3931 and Production Lease 3860 were the focus of our 2014 horizontal drilling campaign in the Thrace Basin. We are the operator of License 3931 and the Osmanli Production Leases, which expire in November 2015 and April 2024, respectively, with extension available under the old and new petroleum laws.

Senova (License 3858). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3858, which covers approximately 122,000 gross acres. Depending on the recompletion results of the Senova-1 well and Akcahalil-1 well, we plan to apply for a production lease on the southern portion of License 3858. We are the operator of License 3858, which expires in May 2015, with extensions available under the old and new petroleum laws. We applied for the conversion of the northern portion of this license to the new petroleum law in the second quarter of 2014 and are currently awaiting GDPA approval.

Tekirdag (Production Lease 3860) and Gazioglu (Production Lease 3861). We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Leases 3860 and 3861, which cover an aggregate of approximately 4,300 gross acres. As of December 31, 2014, we had 26 gross (10.8 net) producing wells on the Tekirdag and Gazioglu production leases. Production Lease 3860 and License 3931 were the focus of our 2014 horizontal drilling campaign in the Thrace Basin. We plan to maintain production to satisfy our obligation on Production Leases 3860 and 3861. We are the operator of Production Leases 3860 and 3861, which expire in December 2023 and December 2021, respectively, with extensions available under the old and new petroleum laws.

Southeastern Turkey. The following map shows our interests in southeastern Turkey at December 31, 2014:

Arpatepe (Production Lease 5003 and License 5025). We own a 50% working interest in Production Lease 5003 and License 5025, which cover approximately 11,200 and 84,800 gross acres, respectively. For 2014, our wellhead production of oil from the Arpatepe field was approximately 64,875 Bbls of oil, at an average rate of approximately 178 Bbl/d. As of December 31, 2014, we had five producing wells on the Arpatepe production lease. We plan to drill the South Goksu-1 exploration well on License 5025 in 2015. Aladdin Middle East, Ltd. is the operator of Production Lease 5003 and License 5025, which expire in November 2028 and February 2016, respectively, with extensions available under the old and new petroleum laws.

Bakuk (License 5064 and Production Lease 5043). We own a 50% working interest in License 5064 and Production Lease 5043. The exploration license covers approximately 61,000 gross acres, and the production lease covers approximately 34,400 gross acres. Production continues from the Bakuk-101 well, and we are evaluating additional offset well locations. Tiway Turkey, Ltd. ("Tiway") is the operator of License 5064 and Production Lease 5043, which expire in June 2016 and January 2032, respectively, with extensions available under the old and new petroleum laws.

Bismil (License 4239). License 4239 was acquired from ARAR during the second quarter of 2013. We own a 100% working interest in the Bismil license, which covers approximately 4,800 gross acres. License 4239 was part of our large Molla 3D acquisition program, and we drilled the Bati Yasince-1 discovery well in the fourth quarter of 2014, which was producing oil as of December 31, 2014. We are the operator of the license, which expires in June 2015. We continue to monitor production and plan to apply for a production lease covering the majority of this acreage in 2015.

Gaziantep (Gazientep License and Alibey License). We own a 62.5% working interest in the Gazientep and Alibey Licenses, subject to a 0.313% overriding royalty interest, which cover the former License 4607 and an aggregate of 123,000 gross acres. We are the operator of the Gazientep and Alibey Licenses, which expire in October 2019. We are currently evaluating additional prospects on the Gaziantep and Alibey Licenses, including an offset to the Alibey-1H discovery well.

Idil (License 4642). We own a 50% working interest in License 4642, which covers approximately 123,000 gross acres. In February 2014, we entered into a farm-out agreement with Onshore Petroleum Company AS ("Onshore"), whereby Onshore will fund the costs, up to $3.5 million, to drill and complete a well targeting the Mardin formation. We began drilling this well in the fourth quarter of 2014 and plan to complete the well during the first half of 2015. We are the operator of License 4642, which expires in October 2016.

Molla (Licenses 4174 and 4845) and West Molla (License 5046). We own a 100% working interest in Licenses 4174, 4845 and 5046, which cover an aggregate of approximately 112,000 gross acres. As of December 31, 2014, we had six gross and net wells producing on the Molla licenses. We continue to interpret the 800 sq. km. 3D seismic data to delineate prospects on the Molla licenses. We are the operator of Licenses 4174, 4845 and 5046, which expire in June 2016, March 2015 and June 2016, respectively, with extensions available under the old and new petroleum laws. We applied for a two-year extension on License 4845 in the fourth quarter of 2014 and are currently awaiting GDPA approval.

Selmo (Production Lease 829). We own a 100% working interest in Production Lease 829, which covers 8,886 acres and includes the Selmo oil field. As of December 31, 2014, there were 60 gross and net producing wells on the Selmo production lease. For 2014, our wellhead production of oil in the Selmo field was approximately 1,027,639 Bbls of oil, at an average rate of approximately 2,815 Bbl/d. The Selmo lease was the focus of a horizontal drilling campaign in 2014, and we initiated a waterflood pilot test program in the first quarter of 2014, in which two Selmo wells were converted to injection wells. We are the operator of Production Lease 829, which expires in June 2025.

Hazro License Application. We have applied with the GDPA to acquire two new license quadrants, L45-c1 and L45-c2, which we believe to be prospective for the Bedinan, Mardin and Hazro formations. There are five competing bids for the acreage, and we are currently awaiting the GDPA's response.

Bulgaria

General. As of December 31, 2014, we held interests in one onshore exploration permit and one onshore production concession in Bulgaria. We acquired all of our Bulgarian interests through the purchase of Direct Bulgaria in February 2011. 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, 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, 2014:

Reserves. As of December 31, 2014, there were no economic 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% to 15%, depending on the proportion of the capital owned by the recipient. No customs duty is payable on the export of petroleum, nor is customs duty payable on the import of material necessary to conduct petroleum operations. 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 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 $25 at December 31, 2014) per square kilometer, or 40 Bulgarian Lev (approximately $25 at December 31, 2014) 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 the company upon conversion to a production concession.

Koynare. We own a 100% working interest, subject to a 3.02% overriding royalty interest and KDL's 50% farm-in interest, in the Koynare production concession covering approximately 163,000 acres. The Koynare Concession Area contains the Deventci-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. In November 2011, we commenced drilling the Deventci-R2 appraisal well on the Koynare Concession Area, which we suspended following the enactment of the Bulgarian government's January 2012 legislation. During the second half of 2013, we resumed drilling the Deventci-R2 directional well on our Koynare Concession Area. In January 2014, we reached target depth of 14,100 feet on the Deventci-R2 well, and conducted a long-term test on the well during the second quarter of 2014 with an initial production test of approximately 2.0 Mmcf/d of natural gas with condensates. In the fourth quarter of 2014, we received approval from the Bulgarian government to acidize the well. We conducted initial stimulation in December 2014 to enhance its productivity and are currently evaluating the results of the stimulation.

Stefenetz. In November 2011, we initiated the application process for a production concession covering approximately 395,000 acres over the southern portion of our former A-Lovech exploration permit. The Stefenetz Concession Area is estimated to contain over 300,000 prospective acres for Etropole shale at a depth of approximately 12,500 feet, which the Bulgarian government has certified as a geologic discovery. During 2012, we initiated an environmental impact assessment, which the Bulgarian government must approve prior to granting the production concession.

In September 2011, we entered into an agreement with Esrey pursuant to which Esrey funded the drilling of an exploration well on the Stefenetz Concession Area to core and test the Etropole shale formation. This well, the Peshtene-R11, reached total depth in late November 2011, from which we collected more than 900 feet of core. We suspended drilling and completion of the Peshtene-R11 well following enactment of the Bulgarian government's January 2012 legislation. We and Esrey are evaluating the core data and developing a conventional completion program for the Peshtene-R11 well. If we obtain a production concession over the Stefenetz Concession Area, Esrey would fund up to an additional $12.5 million in exchange for a 50% working interest in the production concession. The remaining 50% working interest in the production concession would be split equally between us and KDL.

Aglen. We have applied to relinquish the Aglen exploration permit, which covers approximately 1,700 acres within the boundaries of the former A-Lovech exploration permit and lies within the boundary of the Stefenetz Concession

Area. Due to the Bulgarian government's January 2012 legislation, a force majeure event was recognized by the government. As of March 1, 2015, we were still negotiating the relinquishment of this license.

Albania

General. We own 100% of the interests in three onshore oil fields and one gas concession consisting of one onshore gas field and one exploration license, all in Albania. Stream commenced operations in Albania in November 2007, taking over the operation of wells, associated equipment and facilities from Albpetrol, the state owned oil company in Albania. Subsequent to the acquisition of Stream, we have been operating in Albania under the name TransAtlantic Albania Ltd. The following map shows our interests in Albania at December 31, 2014:

Reserves. As of December 31, 2014, we had total net proved reserves of 14,259 Mbbl of oil and 8,249 Mmcf of natural gas, net probable reserves of 10,014 Mbbl of oil and 19,963 Mmcf of natural gas and net possible reserves of 7,152 Mbbl of oil and 31,518 Mmcf of natural gas in Albania.

Commercial Terms. In August 2007, Stream entered into Instruments of Transfer to join four License Agreements between Agjencia Kombëtare e Burimeve Natyrore, the Albanian National Agency of Natural Resources (“AKBN”), and Albpetrol and entered into four Petroleum Agreements with Albpetrol, which together give us the right to access and develop three onshore oil fields and one onshore gas field. The four License Agreements each have a 25-year term, with unlimited five-year renewal options. These fields contain approximately 600 existing wells, of which approximately 250 are producing, with the remainder shut-in predominantly due to failures of production equipment as a result of insufficient capital investment by Albpetrol.

We are required to submit annual work programs and budgets to Albpetrol each year, including the nature and amount of capital expenditures, which is required to be consistent with the plans of development (“PODs”) for the fields approved by AKBN. Significant deviations from the PODs are subject to the approval of AKBN and Albpetrol.

Pursuant to the terms of the Petroleum Agreements, we pay a 2% to 7.2% gross over-riding royalty to Albpetrol, which may be paid in kind or cash. In addition, we are required to pay a royalty to Albpetrol based on the amount of pre-existing production (“PEP”) from the wells taken over by Stream. The PEP royalty is calculated on a well by well basis and is initially equal to 65% to 70% of the PEP preceding the takeover of the well by Stream. The PEP royalty declines at a rate of 10% per year for the oil fields and 5% per year for Delvina.

In 2008, a new 10% mineral tax was enacted by the Albanian Ministry of Finance. The new mineral tax is equal to 10% of gross sales after deducting any PEP royalties paid. Under the Petroleum Agreements, any new financial burdens (including new mineral taxes) are to be neutralized by amendments to the Petroleum Agreements. We are working with officials from Albpetrol and AKBN to finalize amendments to the Petroleum Agreements to neutralize the 10% mineral tax. As of December 31, 2014, we had $10.9 million of tax payments awaiting neutralization.

Ballsh-Hekal. The Ballsh-Hekal field was discovered in 1966 and produces oil from fractured carbonates of Cretaceous-Paleocene age. The oil contains sulphur. The field is developed with an average well spacing of approximately 4 hectares/well (10 acres/well). We believe that a significant number of these wells did not penetrate the entire hydrocarbon column.

We have taken over 23 wells (of which 13 are producing) from Albpetrol in the Ballsh-Hekal field. We believe that a significant number of these wells did not penetrate the entire hydrocarbon column. Albpetrol still operates approximately 60 wells in the field. We have the right to take over the remaining wells at our option. During 2014, our net production, before mineral taxes, was 86 Bbl/d of oil from the field.

Cakran-Mollaj. The Cakran-Mollaj field was discovered in 1977 and is currently producing from fractured carbonates of Cretaceous-Paleocene age. This is the deepest of our fields in Albania at 2,650 to 3,700 meters. The field is developed with an average well spacing of approximately 16 hectares/well (40 acres/well). We took over 70 wells (of which approximately 30 are producing) from Albpetrol. We believe that a significant number of these wells did not penetrate the entire hydrocarbon column.

During 2014, our net production, before mineral taxes, was approximately 307 Bbl/d of oil from this field. We are working on improving the reliability of surface equipment in this field prior to reactivating and recompleting additional wells.

Gorisht-Kocul. Discovered in 1965, the Gorisht-Kocul field is a heavy oil field that produces from fractured carbonates of Cretaceous-Paleocene age. Well depths range from 400 to 1,250 meters, and the oil contains sulphur. The field is fully developed with an average well spacing of approximately 2 hectares/well (5 acres/well). We believe that a significant number of these wells did not penetrate the entire hydrocarbon column.

We took over all 295 wells (of which approximately half are producing) in the Gorisht-Kocul field from Albpetrol. From During 2014, our net production from this field, before mineral taxes, was 449 Bbl/d of oil. We are in the process of conducting two waterflood projects in this reservoir, which have mitigated the natural pressure and production decline in portions of this field. We intend to workover and reactivate existing wells in 2015 with modern rod pumps and progressive cavity pumps.

Delvina Concession. We own the Delvina Concession, which is comprised of the partially developed Delvina field and the Delvina exploration block.

Delvina Field. The Delvina natural gas field was discovered in 1987 and produces natural gas and natural gas liquids from reservoirs at a depth of 2,800 to 3,500 meters from fractured carbonates of Cretaceous- Paleocene age. The Delvina natural gas field is connected to potential markets by an existing pipeline, but needs additional downstream capacity.

The field has two previously producing vertical wells, the Delvina D4 and D12 wells. During the workover of the Delvina D12 well in 2013, after successful stimulation and flow tests, Stream encountered an obstruction in the completion string that could not be removed through solvent injection and is planning workover procedures. We plan to bring the Delvina D4 well back online following workover of the Delvina D12 well. In April 2014, Stream spud the D34H1 well in the Delvina field, reaching a depth of approximately 750 meters before temporarily abandoning drilling due to a lack of funds. Drilling operations on the D34H1 well are expected to resume during the first half of 2015.

Delvina Block. Under the Delvina License Agreement and Petroleum Agreement, we have the right to develop approximately 60,000 acres adjacent to the Delvina natural gas field, referred to as the Delvina Block. The Delvina Block offers significant growth potential.

Summary of Oil and Natural Gas Reserves

The following table summarizes our net proved, probable and possible reserves at December 31, 2014 and 2013.

	Reserves Oil and Condensate (Mbbl)	Natural Gas (Mmcf)	Total (Mboe)
Reserves Category			
December 31, 2014			
Turkey			
Proved reserves			
Proved developed	6,857	9,551	8,449
Proved undeveloped	7,549	6,703	8,666
Total proved	14,406	16,254	17,115
Probable reserves			
Probable developed	1,400	3,035	1,906
Probable undeveloped	10,032	20,760	13,492
Total probable	11,432	23,795	15,398
Possible reserves			
Possible developed	1,457	3,073	1,969
Possible undeveloped	10,571	73,666	22,849
Total possible	12,028	76,739	24,818
Albania			
Proved reserves			
Proved developed	13,900	-	13,900
Proved undeveloped	359	8,249	1,734
Total proved	14,259	8,249	15,634
Probable reserves			
Probable developed	-	-	-
Probable undeveloped	10,014	19,963	13,341
Total probable	10,014	19,963	13,341
Possible reserves			
Possible developed	-	-	-
Possible undeveloped	7,152	31,518	12,405
Total possible	7,152	31,518	12,405
Total			
Proved reserves			
Proved developed	20,757	9,551	22,349
Proved undeveloped	7,908	14,952	10,400
Total proved	28,665	24,503	32,749
Probable reserves	-	-	-
Probable developed	1,400	3,035	1,906
Probable undeveloped	20,046	40,723	26,833
Total probable	21,446	43,758	28,739
Possible reserves			

Possible developed	1,457	3,073	1,969
Possible undeveloped	17,723	105,184	35,254
Total possible	19,180	108,257	37,223
December 31, 2013			
Turkey			
Proved reserves			
Proved developed	4,875	10,450	6,617
Proved undeveloped	4,839	4,589	5,604
Total proved	9,714	15,039	12,221
Probable reserves			
Probable developed	1,057	3,378	1,620
Probable undeveloped	7,063	19,652	10,338
Total probable	8,120	23,030	11,958
Possible reserves			
Possible developed	1,218	3,307	1,769
Possible undeveloped	15,659	74,898	28,142
Total possible	16,877	78,205	29,911

Value of Proved Reserves

The following table shows our estimated future net revenue, PV-10 and Standardized Measure as of December 31, 2014:

(in thousands)	
Future net revenue	$1,519,169
Total PV-10 (1)	$884,387
Total Standardized Measure	$672,082

(1) 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:

(in thousands)	
Total PV-10 (1)	$884,387
Future income taxes	(392,211)
Discount of future income taxes at 10% per annum	179,906
Standardized Measure	$672,082

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, 2014, our estimated proved reserves were 32,749 Mboe, an increase of 20,528 Mboe, or 168.0%, compared to 12,221 Mboe at December 31, 2013. This increase was primarily attributable to the acquisition of Stream, the continued success of our horizontal drilling campaigns in the Selmo oil field and the Thrace Basin and the successful appraisal of the Bahar oil field. The Albanian assets of Stream constituted 15,634 Mboe or 76.2% of the increase. Of these proved reserves, 88.9% are in the proved developed category and are part of the producing oil assets in Albania. The increase in proved reserves was partially offset by sales volumes of 1,883 Mboe in 2014, consisting of 1,339 Mbbls of oil and 3,262 Mmcf of natural gas.

At December 31, 2014, we recorded an increase in proved reserves of 5,208 Mboe through extensions and discoveries. These increases were due to the following factors: (i) horizontal drilling in Selmo, which resulted in the conversion of 2,234 Mboe from probable or possible reserves to proved reserves due to successful wells in the previously under-drilled southeast portion of the field and confirming that oil still remains at, or below, the current oil-water contact; (ii) the addition of 467 Mboe in the Thrace Basin as a result of the Gurgen discovery and successful Sogucak test in the Kuzey Emirali-1 well; (iii) the addition of 2,243 Mboe due to successful appraisal wells on the Bahar structure and (iv) the addition of 264 Mbbls in the Arpatepe oil field as a result of the Arpatepe-7 appraisal well success which extended the field to the southeast.

At December 31, 2014, we recorded an increase in proved reserves due to technical revisions of 1,254 Mbbl and 1,668 Mmcf (1,532 Mboe total). The revision in oil of 1,254 Mbbls was an increase from December 31, 2013, in which we recorded a loss of 436 Mbbls, and was mostly attributable to well performance in Selmo. Prior to initiating the horizontal well campaign in Selmo in 2013, drilling had been halted due to poor vertical well performance. This resulted in negative revisions to estimates for 2013. By contrast, the horizontal wells drilled in late 2013 and throughout 2014 have performed better than original estimates and thus resulted in positive technical revisions. The revision in gas of 1,668 Mmcf was a decrease from December 31, 2013, in which we recorded 3,436 Mmcf in technical revisions and was mostly attributable to a decrease in activity in the Thrace Basin, where we did not introduce any new technology to the gas fields. In 2013, we successfully fracture stimulated the Mezardere formation for the first time. This led to an aggressive recompletion program as we fine-tuned our stimulation methodology which, in turn, greatly increased many behind pipe reserves. The performance of these fracture stimulated wells versus the unstimulated type curves allowed for positive reserve revisions. The estimated undiscounted capital costs associated with our proved reserves is $357.8 million.

Proved Undeveloped Reserves

At December 31, 2014, our estimated proved undeveloped reserves were 10,400 Mboe, an increase of 4,796 Mboe, or 85.6%, compared to 5,604 Mboe at December 31, 2013. Of this increase in proved undeveloped reserves, 1,734 Mboe was from the acquisition of Stream, 1,834 Mboe was from extensions and discoveries from horizontal drilling in Selmo and 1,228 Mboe was from extensions and discoveries in the Molla field and the Thrace Basin in Turkey. All of our proved undeveloped reserves as of December 31, 2014 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 is $266.6 million.

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 retain outside independent engineering firms to prepare estimates of our proved, probable and possible reserves. 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 2014. 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 in Turkey presented as of December 31, 2014 have been prepared by DeGolyer and MacNaughton, our external engineers for Turkey. The technical person at DeGolyer and MacNaughton that is primarily responsible for overseeing the preparation of our reserves estimates in Turkey is a Registered Professional Engineer in the State of Texas and has a Bachelor of Science degree in Mechanical Engineering from Kansas State University. He has over 32 years of experience in oil and natural gas reservoir studies and evaluations and is a member of the Society of Petroleum Engineers.

The estimates of proved, probable and possible reserves in Albania presented as of December 31, 2014 have been prepared by Deloitte LLP, our external engineers for Albania. The technical person at Deloitte LLP that is primarily responsible for overseeing our reserves estimates in Albania has a Bachelor of Science degree in Chemical Engineering from the University of Calgary. He has over 20 years of experience in oil and gas reservoir engineering and reserves determination.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with DeGolyer and MacNaughton and Deloitte LLP to ensure the integrity, accuracy and timeliness of data furnished to them for the preparation of their reserves estimates. Our chief reservoir engineer has over 42 years of experience in oil and natural gas reservoir studies and evaluations. He has a Bachelor of Science degree in Petroleum Engineering from Colorado School of Mines and a Masters of Business Administration degree from the University of Phoenix. He is a Registered Professional Engineer in the state of Colorado, and is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

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, 2014 included a detailed evaluation of our Selmo, Arpatepe, Bakuk, Molla and Thrace Basin properties in Turkey and our West Koynare field in Bulgaria. 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.

The estimates of proved, probable and possible reserves prepared by Deloitte LLP for the year ended December 31, 2014 included a detailed evaluation of our Ballsh-Hekal, Cakran-Mollaj, Gorisht-Kocul and Delvina properties in Albania. Deloitte LLP 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 and Deloitte LLP evaluated the Company's reserves as of December 31, 2014, 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 at December 31, 2014) for 2014, 2013 and 2012:

	Sales Volumes		
Year	Oil (1) (Bbls)	Natural Gas (Mcf)	Total (Boe)
2014			
Total Turkey	1,302,439	3,258,537	1,845,529
Selmo field	1,023,877	–	1,023,877
Total Albania	36,200	–	36,200
Gorisht-Kocul field	19,306	–	19,306
2013			
Total Turkey	932,463	3,495,698	1,515,079
Selmo field	665,025	–	665,025
2012			
Total Turkey	947,998	4,204,629	1,648,720
Selmo field	813,222	–	813,222

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

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 2014, 2013 and 2012:

	2014	2013	2012 (1)
Turkey:			
Average Sales Price Oil ($/Bbl)	$82.92	$101.05	$102.60
Natural Gas ($/Mcf)	$8.67	$9.43	$8.72
Unit Costs Production ($/Boe)	$8.56	$10.62	$9.20
Albania:			
Average Sales Price Oil ($/Bbl)	$52.43	$–	$–
Natural Gas ($/Mcf)	$–	$–	$–
Unit Costs Production ($/Boe)	$31.15	$–	$–

(1) We have recalculated the oil and natural gas costs per Boe for the year ended December 31, 2012 based on working interest volumes before royalty deductions to conform to current year presentation.

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 2014, 2013 and 2012:

	Development Wells		Exploratory Wells	
	Productive	Dry	Productive	Dry
Turkey:				
2014	14.7	2.0	4.6	0.4
2013	10.5	0.5	3.5	4.4
2012	14.5	1.4	4.0	7.9
Bulgaria:				
2014	–	–	–	–
2013	–	–	–	–
2012	–	–	–	–
Albania:				
2014	–	–	–	–
2013	–	–	–	–
2012	–	–	–	–

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, 2014:

	Oil		Natural Gas	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Turkey	73.0	70.0	141.0	67.0
Bulgaria	–	–	–	–
Albania	202.0	202.0	–	–

(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, 2014:

	Developed Acres	
	Gross (1)	Net (2)
Turkey	210,711	106,373
Albania	19,993	19,993

Total	230,704	126,366

(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, 2014:

	Undeveloped Acres	
	Gross (1)	Net (2)
Turkey	1,690,406	1,034,854
Bulgaria	567,106	567,106
Albania	55,635	55,635
Total	2,313,147	1,657,595

(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 scheduled to expire in the next five years:

	Undeveloped Acres (1)		% of Total Undeveloped Acres
	Gross (2)	Net (3)	Net (3)
2015	731,916	397,568	24.0
2016	568,466	374,928	22.6
2017	120,726	50,101	3.0
2018	–	–	–
2019	152,107	95,067	5.7

(1) Excludes the Stefenetz Concession Area for which we have applied for a production concession.
(2) "Gross" means the total number of acres in which we had a working interest.
(3) "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 2015 through the execution of our current work commitments.

Item 3. Legal Proceedings

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. 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").

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 one claim for damages filed in the Kozluk Civil Court of First Instance. The plaintiffs in each of these cases are the same villagers in the Surface Litigation. 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 these nuisance cases until there is a resolution of the Surface Litigation. On December 27, 2012, the Kozluk Civil Court of First Instance dismissed the damages case, and the plaintiffs appealed that decision.

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 file 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 Kozluck 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.

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

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

Canada

Our common shares are traded in Canada on the Toronto Stock Exchange (the “TSX”) under the trading symbol “TNP”. The following table sets forth the quarterly high and low sales prices per common share in Canadian dollars on the TSX for the periods indicated. The high and low sales prices per common share for each quarterly period within the two most recent fiscal years indicated below have been adjusted to reflect our 1-for-10 reverse stock split effected March 6, 2014.

	High	Low
2014:		
Fourth Quarter	$9.85	$6.00
Third Quarter	$13.29	$10.10
Second Quarter	$12.04	$8.62
First Quarter	$9.80	$7.80
2013:		
Fourth Quarter	$10.00	$7.70
Third Quarter	$10.10	$6.10
Second Quarter	$9.40	$7.10
First Quarter	$10.70	$8.50

United States

Our common shares are traded in the United States on the NYSE MKT exchange under the trading symbol “TAT”. The following table sets forth the high and low sales price per common share in U.S. Dollars on the NYSE MKT for the periods indicated. The high and low sales prices per common share for each quarterly period within the two most recent fiscal years indicated below have been adjusted to reflect our 1-for-10 reverse stock split effected March 6, 2014.

	High	Low
2014:		
Fourth Quarter	$8.65	$5.15
Third Quarter	$12.48	$8.99
Second Quarter	$11.39	$7.89
First Quarter	$8.84	$7.00
2013:		
Fourth Quarter	$11.00	$7.30
Third Quarter	$9.70	$7.10

Second Quarter	$9.10	$6.90
First Quarter	$10.40	$8.80

Common Shares and Dividends

As of March 6, 2015, we had 40,777,149 common shares issued and outstanding and held by 79 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

The following table summarizes selected consolidated financial information from continuing operations for each of the five years in the period ended December 31, 2014. All periods presented have been adjusted to reflect our oilfield services business segment and Moroccan segment as discontinued operations. You should read the information set forth below in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and notes thereto included elsewhere in this Annual Report on Form 10-K.

	Year Ended December 31,				
	2014 (1)	2013	2012	2011	2010
	(amounts in thousands, except per share amounts)				
Total revenues	$140,728	$130,827	$143,908	$128,905	$70,854
Seismic and other exploration	4,285	14,009	5,040	11,542	16,883
Net income (loss) from continuing operations	29,096	(13,271)	(6,373)	(77,574)	(29,545)
Comprehensive income (loss) income	14,751	(50,686)	38,470	(173,012)	(77,514)
Basic net income (loss) per common share from continuing operations	0.77	(0.36)	(0.17)	(2.18)	(0.95)
Basic weighted average number of shares outstanding	37,829	37,069	36,742	35,597	31,249

	As of December 31,				
	2014 (1)	2013	2012	2011	2010
	(amounts in thousands)				
Total assets	$546,403	$346,586	$358,258	$448,802	$473,968
Long-term liabilities	183,811	63,619	72,819	112,904	62,486

Shareholders' equity	211,464	167,317	213,827	171,273	276,057
Capital expenditures, including acquisitions (2)	141,810	99,951	81,824	152,440	170,317

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(1) Includes the results of operations of Stream since November 18, 2014.

(2) Excludes seismic and other exploration expenditures.

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, 2014, we held interests in approximately 1.8 million net acres of developed and undeveloped oil and natural gas properties in Turkey, Albania and Bulgaria. As of March 1, 2015, approximately 36% 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.

Recent Decline in Oil Prices

As a result of the recent decline in prices for Brent crude, we have reduced our planned capital expenditures and deferred a significant amount of our planned exploration and development until prices for Brent crude improve. In order to mitigate the impact of reduced prices on our 2015 cash flows and liquidity, we have implemented cost reduction measures and will continue to implement cost-cutting initiatives to reduce our operating costs and general and administrative expenses. These initiatives include the negotiation of exploration and development and operating cost reductions with several key vendors and plans to continue to pursue further reductions. We believe this strategy will allow us to preserve our liquidity in order to execute our 2015 development program and continue to meet our contractual obligations.

Notwithstanding these measures, there remain risks and uncertainties that could negatively impact our results of operations and financial condition. For example, reductions in our borrowing capacity as a result of a redetermination to our borrowing base could have an impact on our capital resources and liquidity. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices.

2014 Financial and Operational Performance

- We reported $29.1 million of net income from continuing operations. This includes a $37.5 million gain on our commodity derivative contracts and a $6.0 million foreign exchange loss.
- We derived 78.1% of our revenues from the production of oil, 20.1% of our revenues from the production of natural gas and 1.8% of our revenues from other sources during the year ended December 31, 2014.
- Total oil and natural gas sales revenues increased 8.6% to $138.2 million for the year ended December 31, 2014, from $127.3 million in 2013. The increase was primarily the result of an increase in sales volumes of 365 Mboe, which was partially offset by a decrease in the average sales price of $10.44 per Boe.
- Wellhead production was 1,345 Mbbls of oil and 3,567 Mmcf of natural gas for the year ended December 31, 2014, as compared to 942 Mbbls of oil and 3,932 Mmcf of natural gas for 2013.
-

In 2014, we incurred $146.1 million in total capital expenditures, including license acquisition and seismic expenditures, from continuing operations, as compared to $114.0 million in 2013.

- As of December 31, 2014, we had $106.0 million in long-term debt and $52.6 million in short-term debt, as compared to $26.5 million in long-term debt and $43.3 million in short-term debt as of December 31, 2013.

Recent Developments

For information on our recent developments, see "Item 1. Business—Recent Developments."

2014 Operations

During 2014, we implemented a three-part strategy to increase production and cash flow in Turkey: (i) the Molla vertical program, (ii) the Selmo field redevelopment program, which included horizontal drilling, and (iii) the Thrace Basin development program, which included a combination of vertical and horizontal drilling. We also began operations in Albania with the acquisition of Stream. For additional information on our current operations, see "Item 1. Business—Current Operations."

Planned Operations

We plan to satisfy license earning obligations for our core properties in Turkey and to drill the D34H1 well in Albania. For more information on our planned 2015 operations, see “Item 1. Business—Planned Operations.”

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 2—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) the Company's history in exploring the area, (iii) the Company's future drilling plans per its capital drilling program prepared by the Company's 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 810-10-65"). 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 and is the U.S.

Dollars in Albania. 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 earnings.

Goodwill. In accordance with ASC 350, Intangibles-Goodwill and Other ("ASC 350"), goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise. ASC 350 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. We assessed the qualitative factors at December 31, 2014 and, based upon the results of the qualitative assessment, we determined that it was not necessary to perform the two-step goodwill impairment test and that our goodwill was not impaired. All of our goodwill is attributable to our Turkey operating segment.

Oil and Gas Reserves. The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated and combined 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 and Deloitte LLP, our independent reserve engineers, to independently evaluate our properties that result in estimates for all of our estimated proved reserves at December 31, 2014.

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 bases. 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 April 2014, the FASB issued Accounting Standards Update ("ASU") 2014-08, Reporting Discontinued Operations and Disclosures of Components of an Entity ("ASU 2014-08"). ASU 2014-08 revises the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have (or will have) a major effect on an entity's operations and financial results, removing the lack of continuing involvement criteria and requiring discontinued operations reporting for the disposal of an equity method investment that meets the definition of discontinued operations. The update also requires expanded disclosures for discontinued operations, including disclosure of pretax profit or loss of an individually significant component of an entity that does not qualify for discontinued operations reporting. The update is effective prospectively to all periods beginning after December 15, 2014. Currently, we do not expect the adoption of ASU 2014-08 to have a material impact on our consolidated financial statements or results of operations.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). ASU 2014-09 amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods or services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The update is effective for periods beginning after December 15, 2016. We are currently assessing the potential impact of ASU 2014-09 on our consolidated financial statements and results of operations.

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"), an amendment to FASB Accounting Standards Codification ("ASC") Topic 205, Presentation of Financial Statements. This update provides guidance on management's responsibility in evaluating whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. This ASU 2014-15 is effective for annual periods ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. We do not expect the adoption of ASU 2014-15 to have a material impact on our consolidated financial statements or results of operations. If events occur in future periods that could affect our ability to continue as a going concern, we will provide the disclosures required by ASU 2014-15.

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

Results of Operations—Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

	Year Ended December 31,		Change
	2014	2013	2014-2013
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	1,339	933	406
Natural gas (Mmcf)	3,262	3,512	(250)
Total production (Mboe)	1,883	1,518	365
Average daily sales volumes (Boepd)	5,157	4,159	998
Average prices:			
Oil (per Bbl)	$82.10	$101.02	$(18.92)
Natural gas (per Mcf)	$8.66	$9.40	$(0.74)
Oil equivalent (per Boe)	$73.40	$83.84	$(10.44)
Revenues:			
Oil and natural gas sales	$138,174	$127,270	$10,904
Sales of purchased natural gas	2,127	2,581	(454)
Other	427	976	(549)
Total revenues	140,728	130,827	9,901
Costs and expenses:			
Production	19,999	18,602	1,397
Exploration, abandonment and impairment	19,864	27,333	(7,469)
Cost of purchased natural gas	2,055	2,247	(192)
Seismic and other exploration	4,285	14,009	(9,724)
Revaluation of contingent consideration	(2,500)	(5,000)	2,500
General and administrative	31,625	29,020	2,605
Depletion	46,812	38,996	7,816
Depreciation and amortization	2,115	2,326	(211)
Interest and other expense	6,213	3,929	2,284
Foreign exchange loss	5,998	9,663	(3,665)
Deferred income tax expense	11,263	979	10,284
Gain (Loss) on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(2,100)	(3,521)	1,421
Change in fair value on commodity derivative contracts	39,554	823	38,731

Total gain (loss) on commodity derivative contracts	37,454	(2,698)	40,152
Oil and natural gas costs per Boe:			
Production	$9.23	$10.72	$ (1.49)
Depletion	$21.59	$22.48	$ (0.89)

Oil and Natural Gas Sales. Excluding sales of purchased natural gas, total oil and natural gas sales increased to $138.2 million in 2014, from $127.3 million in 2013. Of this increase, $30.5 million resulted from an increase in sales volumes of 365 Mboe. Sales volumes increased (i) primarily on our southeast Turkey oil wells due to our successful horizontal drilling program in 2014 and (ii) due to the acquisition of Stream. This increase was partially offset by a decrease of $19.4 million, attributable to a lower average realized prices per Boe in 2014. Our average price received decreased $10.44 to $73.40 per Boe in 2014, compared to $83.84 per Boe in 2013.

Production. Production expenses for 2014 increased to $20.0 million from $18.6 million in 2013. The increase was primarily attributable to the acquisition of Stream in 2014. However, production expense per Boe decreased by $1.49 to $9.23 per Boe in 2014, compared to $10.72 per Boe in 2013. This decrease was primarily attributable to an increase in our production volumes during 2014 compared to 2013.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs decreased to $19.9 million in 2014, compared to $27.3 million for 2013. The decrease was primarily due to a $15.5 million decrease in exploratory dry hole expense offset by $6.5 million increase in impairment and abandonment. The majority of our impairment and abandonment charges of $17.5 million in 2014 related to three exploratory wells in Turkey.

Seismic and Other Exploration. Seismic and other exploration costs decreased to $4.3 million for 2014, compared to $14.0 million for 2013. The decrease was primarily due to seismic acquisition activities conducted on our West Molla license during 2013.

Revaluation of Contingent Consideration. As a result of the amendment to the purchase agreement with Direct Petroleum LLC ("Direct"), during 2014, we recognized the reversal of a $2.5 million contingent liability that was originally recorded in 2011.

General and Administrative. General and administrative expense increased $2.6 million to $31.6 million for 2014, compared to $29.0 million for 2013. The increase was primarily due to a $1.5 million charge to bad debt expense for an uncollectible receivable and $1.2 million of acquisition expenses related to the acquisition of Stream. This was partially offset by a decrease in office rent expense of $0.3 million during 2014.

Depletion. Depletion expense increased to $46.8 million or $21.59 per Boe for 2014, compared to $39.0 million or $22.48 per Boe for 2013. The increase was due primarily to additions to proved properties on our Selmo and Bahar fields and an increase in production volumes during 2014.

Interest and Other Expense. Interest and other expense increased to $6.2 million in 2014, compared to $3.9 million in 2013. The increase was primarily due to an increase in our average level of debt outstanding during 2014 compared to 2013. Excluding debt assumed in the Stream acquisition, at December 31, 2014, we had $135.7 million of total debt outstanding, compared to $69.8 million at December 31, 2013. Also contributing to the increase was a $0.5 million write-off of loan financing costs related to our prior amended and restated credit facility, which was repaid in May 2014.

Foreign Exchange Loss. We recorded a foreign exchange loss of $6.0 million in 2014, compared to a loss of $9.7 million in 2013. 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 New Turkish Lira ("TRY") amount if it has not been settled previously. The decrease in foreign exchange loss in 2014 was due to a 8.6% devaluation of the TRY compared to the U.S. Dollar in 2014, compared to a 19.7% devaluation during 2013.

Deferred Income Tax Expense. Deferred income tax expense increased to $11.3 million for the year ended December 31, 2014, compared to $1.0 million for 2013. The increase was primarily due to changes in temporary differences between our U.S. GAAP and statutory balances in Turkey.

Gain (Loss) on Commodity Derivative Contracts. During 2014, we recorded a net gain on commodity derivative contracts of $37.5 million, compared to a net loss of $2.7 million for 2013. In 2014, we recorded a $39.6 million gain to mark our commodity derivative contracts to their fair value and a $2.1 million loss on settled contracts. In 2013, we recorded a $0.8 million gain to mark our commodity derivative contracts to their fair value and a $3.5 million loss on settled contracts. We are required under our Senior Credit Facility to hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey.

Results of Operations—Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Year Ended December 31, 2013	2012	Change 2013-2012
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Sales volumes:			
Oil (Mbbl)	933	949	(16)
Natural gas (Mmcf)	3,512	4,238	(726)
Total production (Mboe)	1,518	1,655	(137)
Average daily sales volumes (Boepd)	4,159	4,522	(363)
Average prices:			
Oil (per Bbl)	$ 101.02	$ 102.55	$ (1.53)
Natural gas (per Mcf)	$ 9.40	$ 8.68	$ 0.72
Oil equivalent (per Boe)	$ 83.84	$ 81.04	$ 2.80
Revenues:			
Oil and natural gas sales	$ 127,270	$ 134,113	$ (6,843)
Sales of purchased natural gas	2,581	7,882	(5,301)
Other	976	1,913	(937)
Total revenues	130,827	143,908	(13,081)
Costs and expenses:			
Production	18,602	17,804	798
Exploration, abandonment and impairment	27,333	39,993	(12,660)
Cost of purchased natural gas	2,247	7,694	(5,447)
Seismic and other exploration	14,009	5,040	8,969
Revaluation of contingent consideration	(5,000)	-	(5,000)
General and administrative	29,020	33,947	(4,927)
Depletion	38,996	26,024	12,972
Depreciation and amortization	2,326	2,191	135
Interest and other expense	3,929	8,340	(4,411)
Foreign exchange loss	9,663	(1,083)	10,746
Deferred income tax expense	979	1,817	(838)
Loss on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(3,521)	(3,829)	308
Change in fair value on commodity derivative contracts	823	(1,719)	2,542
Total loss on commodity derivative contracts	(2,698)	(5,548)	2,850
Oil and natural gas costs per Boe:			
Production	$ 10.72	$ 9.42	$ 1.30
Depletion	$ 22.48	$ 13.77	$ 8.71

Oil and Natural Gas Sales. Excluding sales of purchased natural gas, total oil and natural gas sales decreased to $127.3 million in 2013, from $134.1 million in 2012. Of this decrease, $11.1 million resulted from a decrease in sales volumes of 137 Mboe. Sales volumes decreased primarily on our Thrace Basin wells due to high decline rates. This decrease was partially offset by an increase of $4.3 million, attributable to higher average realized prices per Boe resulting from the production of a higher percentage of oil and the realization of higher natural gas prices. Our average price received increased $2.80 to $83.84 per Boe in 2013, compared to $81.04 per Boe in 2012.

Production. Production expenses for 2013 increased to $18.6 million from $17.8 million in 2012. The increase was primarily attributable to the sale of our oilfield services business in June 2012. Certain expenses that were classified as inter-company and eliminated upon consolidation prior to the sale are now classified as third party. Production expense per Boe increased $1.30 to $10.72 per Boe in 2013, compared to $9.42 per Boe in 2012. This increase is primarily attributable to a decrease in our production volumes during 2013 as compared to 2012, combined with a higher percentage of oil production, which has a higher production cost per Boe compared to natural gas.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs decreased to $27.3 million in 2013, compared to $40.0 million for 2012. The decrease was primarily due to an $8.7 million decrease in exploratory dry hole expense and a $4.0 million decrease in impairment and abandonment. The majority of our impairment and abandonment charges of $11.3 million in 2013 related to our exploration licenses in Turkey. In 2012, impairment was taken on a portion of our proved properties in Turkey for $6.7 million and on our exploration licenses in Turkey for $8.4 million. Additionally, in 2013, nine wells were written off to exploration, abandonment and impairment for $16.0 million, compared to 16 wells which were written off in 2012 for $24.7 million.

Seismic and Other Exploration. Seismic and other exploration costs increased to $14.0 million for 2013, compared to $5.0 million for 2012. The increase was primarily due to seismic acquisition activities conducted on our West Molla license during 2013.

Revaluation of Contingent Consideration. As a result of the amendment to the purchase agreement with Direct, during 2013, we recognized the reversal of a $5.0 million contingent liability that was originally recorded in 2011.

General and Administrative. General and administrative expense decreased $4.9 million to $29.0 million for 2013, compared to $33.9 million for 2012. The decrease was primarily due to a decrease in employee-related costs of $2.1 million and a decrease in legal, accounting and consultancy expense of $0.5 million. Employee-related costs decreased due to a reduction in head count in 2013, and legal, accounting and consultancy expenses decreased primarily due to the timely filing of our quarterly reports on Form 10-Q for the quarters ended June 30, 2013 and September 30, 2013. Also contributing to the decrease was a $2.0 million accrual for a contingency related to our Aglen exploration permit in Bulgaria, which was recognized during 2012. The remaining decrease of $0.3 million was attributable to our overall cost reduction efforts.

Depletion. Depletion expense increased to $39.0 million for 2013, compared to $26.0 million in 2012. The increase was due primarily to capital additions in the Selmo, Tekirdag, Goksu and Molla fields and to downward reserves revisions, which increased the depletion rates for certain fields.

Interest and Other Expense. Interest and other expense decreased to $3.9 million for 2013, compared to $8.3 million for 2012. The decrease was primarily due to a decrease in our average debt levels from 2013 to 2012. In June 2012, we repaid $129.2 million of debt with proceeds from the sale of our oilfield services business.

Foreign Exchange Loss (Gain). We recorded a foreign exchange loss of $9.7 million in 2013, compared to a gain of $1.1 million in 2012. 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. The increased foreign exchange loss in 2013 is due to a 19.7% decrease in value of the TRY compared to the U.S. Dollar in 2013.

Deferred Income Tax Expense. Deferred income tax expense decreased to $1.0 million for the year ended December 31, 2013, compared to $1.8 million for 2012. The decrease was primarily due to changes in temporary differences between our U.S. GAAP and statutory balances in Turkey.

Loss on Commodity Derivative Contracts. During 2013, we recorded a net loss on commodity derivative contracts of $2.7 million, compared to a net loss of $5.5 million for 2012. In 2013, we recorded a $0.8 million gain to mark our commodity derivative contracts to their fair value and a $3.5 million loss on settled contracts. In 2012, we recorded a $1.7 million loss to mark our commodity derivative contracts to their fair value and a $3.8 million loss on settled contracts. We were required under our prior amended and restated credit facility to hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey.

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Discontinued Operations. All revenues and expenses associated with our Moroccan operations and oilfield services business for 2013 and 2012 have been included in discontinued operations. The results of operations for our Moroccan operations and oilfield services business were as follows:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Revenues:		
Oil and gas sales	$–	$68
Oilfield services	–	19,888
Total revenues	–	19,956
Costs and expenses:		
Production	178	789
Oilfield services costs	25	12,955
General and administrative	302	10,938
Total costs and expenses	505	24,682
Operating loss	(505)	(4,726)
Other income (expense):		
Interest and other expense	(8)	(156)
Interest and other income	71	562
Foreign exchange loss	–	(763)
Total other income (expense)	63	(357)
Loss before income taxes from discontinued operations	(442)	(5,083)
Gain on sale of discontinued operations	–	35,999
Income tax provision	–	(8,297)
Net (loss) income from discontinued operations	$(442)	$22,619

Capital Expenditures

For 2014, we incurred $146.1 million in total capital expenditures, including license acquisition, seismic and corporate expenditures, compared to $114.0 million for 2013. The increase in capital expenditures was primarily due to the acquisition of Stream.

We expect our net field capital expenditures for 2015 to range between $12.0 and $38.0 million. We expect net field capital expenditures during 2015 to include approximately $12.0 million of drilling and completion expense for five gross obligation wells to hold our most promising licenses in Turkey. We expect cash on hand, proceeds from the private placement of convertible notes, and cash flow from operations will be sufficient to fund our 2015 net field capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. Our projected 2015 capital expenditure budget is subject to change.

Liquidity and Capital Resources

Our primary sources of liquidity for 2014 were our cash and cash equivalents, cash flow from operations, proceeds from the issuance of our convertible notes and borrowings under our Senior Credit Facility. At December 31, 2014, we had cash and cash equivalents of $35.1 million, $106.0 million in long-term debt, $52.6 million in short-term debt and a working capital deficit of $45.9 million (excluding assets and liabilities held for sale, deferred income taxes and derivative assets), compared to cash and cash equivalents of $12.9 million, $26.5 million in long-term debt, $43.3

million in short-term debt and working capital deficit of $39.4 million at December 31, 2013 (excluding assets and liabilities held for sale, deferred income taxes and derivative liabilities). Cash provided by operating activities from continuing operations during 2014 was $78.1 million, compared to cash provided by operating activities from continuing operations of $68.8 million in 2013, due primarily to an increase in oil revenues.

Cash used in investing activities from continuing operations during 2014 increased to $117.2 million, compared to cash used in investing activities from continuing operations of $105.1 million in 2013, due primarily to an increase in drilling operations on our Bahar oil field. Additionally, cash provided by financing activities from continuing operations was $61.6 million in 2014, compared to cash provided in financing activities from continuing operations of $37.0 million in 2013, due primarily to an increase in our borrowings.

As a result of the recent decline in prices for Brent crude, we have reduced our planned capital expenditures and deferred a significant amount of our planned exploration and development until prices for Brent crude improve. In order to mitigate the impact of reduced prices on our 2015 cash flows and liquidity, we have implemented cost reduction measures and will continue to implement cost-cutting initiatives to reduce our operating costs and general and administrative expenses. These initiatives include the negotiation of exploration and development and operating cost reductions with several key vendors and plans to continue to pursue further reductions. We believe this strategy will allow us to preserve our liquidity in order to execute our 2015 development program and continue to meet our contractual obligations.

We believe that our cash flows from operations and existing cash on hand are sufficient to conduct our planned operations through 2015 and meet our contractual requirements, including license obligations. Additionally, at current Brent crude prices, our current hedge positions provide additional liquidity on a monthly recurring basis.

Notwithstanding these measures, there remain risks and uncertainties that could negatively impact our results of operations and financial condition. For example, reductions in our borrowing capacity as a result of a redetermination to our borrowing base could have an impact on our capital resources and liquidity. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices.

As of December 31, 2014, the outstanding principal amount of our debt was $158.6 million. In addition to cash, cash equivalents and cash flow from operations, at December 31, 2014, we had a Senior Credit Facility, a credit facility with a Turkish bank, convertible notes, a term loan facility, a prepayment agreement, a note with Viking International Limited ("Viking International") and a shareholder loan, all of which are discussed below.

Senior Credit Facility. On May 6, 2014, DMLP, TEMI, Talon Exploration, TransAtlantic Turkey Ltd., Amity and Petrogas (collectively the "Borrowers") entered into the Senior Credit Facility with BNP Paribas and the IFC. Each of the Borrowers is our wholly owned subsidiary. The Senior Credit Facility is guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide (each, a "Guarantor").

The amount drawn under the Senior Credit Facility may not exceed the lesser of (i) $150.0 million, (ii) the borrowing base amount at such time, (iii) the aggregate commitments of all lenders at such time, and (iv) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender's individual commitment. The lenders have an initial aggregate commitment of $80.0 million, with individual commitments of $40.0 million each. The Company has the ability to increase the commitments up to an aggregate of $150.0 million by March 31, 2016. On the first day of each fiscal quarter commencing April 1, 2016, the lenders' commitments are subject to reduction in an amount equal to 7.69% of the aggregate commitments in effect on April 1, 2016.

The borrowing base amount is re-determined semi-annually on April 1st and October 1st of each year, beginning April 1, 2015. The borrowing base was $71.5 million as of December 31, 2014. The borrowing base amount equals, for any calculation date, the lowest of:

- the debt value which results in the field life coverage ratio for such calculation date being 1.50 to 1.00; and
- the debt value which results in the loan life coverage ratio for such calculation date being 1.30 to 1.00.

The Senior Credit Facility matures on the earlier of (i) March 31, 2019, or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual banking case of BNP Paribas and the Borrowers determines that the aggregate amount of hydrocarbons to be produced from the borrowing base assets in Turkey are less than 25% of the amount of hydrocarbons to be produced from the borrowing base assets shown in the initial banking case prepared by BNP Paribas and the Borrowers. The Senior Credit Facility bears various letter of credit sub-limits, including among other things, sub-limits of up to (i) $10.0 million, (ii) the aggregate available unused and uncancelled portion of the lenders' commitments or (iii) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender's individual commitment.

Loans under the Senior Credit Facility accrue interest at a rate of three-month LIBOR plus 5.00% per annum (5.26% at December 31, 2014). The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.00% per annum of the unused and uncancelled portion of the aggregate commitments that is less than or equal to the maximum available amount under the Senior Credit Facility, and (b) 1.00% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Senior Credit Facility and is not available to be borrowed, (ii) on the date of issuance of any letter of credit, a fronting fee in an amount equal to 0.25% of the original maximum amount to be drawn under such letter of credit and (iii) a per annum letter of credit fee for each letter of credit issued equal to the face amount of such letter of credit multiplied by (a) 1.0% for any letter of credit that is cash collateralized or backed by a standby letter of credit issued by a financial institution acceptable to BNP Paribas or (b) 5.00% for all other letters of credit.

The Senior Credit Facility is secured by a pledge of (i) the local collection accounts and offshore collection accounts of each of the Borrowers, (ii) the receivables payable to each of the Borrowers, (iii) the shares of each Borrower and (iv) substantially all of the present and future assets of the Borrowers.

The Borrowers are required to comply with certain financial and non-financial covenants under the Senior Credit Facility, including maintaining the following financial ratios during the four most recently completed fiscal quarters occurring on or after March 31, 2014:

- ratio of combined current assets to combined current liabilities of not less than 1.10 to 1.00;
- ratio of EBITDAX (less non-discretionary capital expenditures) to aggregate amounts payable under the Senior Credit Facility of not less than 1.50 to 1.00;
- ratio of EBITDAX (less non-discretionary capital expenditures) to interest expense of not less than 4.00 to 1.00; and
- ratio of total debt to EBITDAX of less than 2.50 to 1.00.

The Senior Credit Facility defines EBITDAX as net income (excluding extraordinary items) plus, to the extent deducted in calculating such net income, (i) interest expense (excluding interest paid-in-kind, or non-cash interest expense and interest incurred on certain subordinated intercompany debt or interest on equity recapitalized into subordinated debt), (ii) income tax expense, (iii) depreciation, depletion and amortization expense, (iv) amortization of intangibles and organization costs, (v) any extraordinary, unusual or non-recurring non-cash expenses or losses, (vi) any other non-cash charges (including dry hole expenses and seismic expenses, to the extent such expenses would be capitalized under the “full cost” accounting method), (vii) expenses incurred in connection with oil and gas exploration activities entered into in the ordinary course of business (including related drilling, completion, geological and geophysical costs), and (viii) transaction costs, expenses and fees incurred in connection with the negotiation, execution and delivery of the Senior Credit Facility and the related loan documents, minus, to the extent included in calculating net income, (a) any extraordinary, unusual or non-recurring income or gains (including, gains on the sales of assets outside of the ordinary course of business) and (b) any other non-cash income or gains.

Pursuant to the terms of the Senior Credit Facility, until amounts under the Senior Credit Facility are repaid, each of the Borrowers shall not, and shall cause each of its subsidiaries not to, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of any Borrower or its subsidiaries to create any liens, (iii) enter into any merger, consolidation or amalgamation, liquidate or dissolve, (iv) dispose of any property or business, (v) pay any dividends, distributions or similar payments to shareholders, (vi) make certain types of investments, (vii) enter into any transactions with an affiliate, (viii) enter into a sale and leaseback arrangement, (ix) engage in any business or business activity, own any assets or assume any liabilities or obligations except as necessary in connection with, or reasonably related to, its business as an oil and natural gas exploration and production company or operate or carry on business in any jurisdiction outside of Turkey or its jurisdiction of formation, (x) change its organizational documents, (xi) permit its fiscal year to end on a day other than December 31st or change its method of determining fiscal quarters, or alter the accounting principles it uses, (xii) modify certain hydrocarbon licenses and agreements or material contracts, (xiii) enter into any hedge agreement for speculative purposes, (xiv) open or maintain new deposit, securities or commodity accounts, (xv) use the proceeds from any loan in the territories of any country that is not a member of the World Bank, (xvi) incur any expenditure that is not covered by the projections in the most recent corporate cashflow projection, (xvii) modify its social and environmental action plans as determined in conjunction with IFC, (xviii) enter into any transaction or engage in any activity prohibited by the United Nations Security Council, or (xix) engage in any corrupt, fraudulent, coercive, collusive or obstructive practice.

An event of default under the Senior Credit Facility includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control is an event of default. A change of control is defined as the occurrence of any of the following: (i) our failure to own, of record and beneficially, all of the equity of the Borrowers or any Guarantor or to exercise, directly or indirectly, day-to-day management and operational control of any Borrower or Guarantor; (ii) the failure by the Borrowers to own or hold, directly or indirectly, all of the interests granted to Borrowers pursuant to certain hydrocarbon licenses designated in the Senior Credit Facility; or (iii) (a) Mr. Mitchell ceases for any reason to be the executive chairman of our board of directors at any time, (b) Mr. Mitchell and certain of his affiliates cease to own of record and beneficially at least 35% of our common shares; or (c) any person or group, excluding Mr. Mitchell and certain of his affiliates, shall become, or obtain rights to become, the beneficial owner, directly or indirectly, of more than 35% of our outstanding common shares entitled to vote for members of our board of directors on a fully-diluted basis; provided, that, if Mr. Mitchell ceases to be executive chairman of our board of directors by reason of his death or disability, such event shall not constitute an event of default unless we have not appointed a successor reasonably acceptable to the lenders within 60 days of the occurrence of such event.

Pursuant to the Senior Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with BNP Paribas that hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey. TEMI has entered into three-way collar contracts with BNP Paribas, which hedge the price of oil through March 2019.

At December 31, 2014, we had borrowings of $68.3 million under the Senior Credit Facility and $3.2 million of available borrowing capacity. At December 31, 2014, we were not in compliance with Section 8.16(a) of our Senior Credit Facility, which requires the Borrowers to maintain a current ratio of not less than 1.10:1.0. The lenders have granted the Borrowers a waiver on the current ratio requirement through March 31, 2015. At March 15, 2015, we had no availability under the Senior Credit Facility.

TBNG Credit Facility. TBNG has a fully drawn credit facility with a Turkish bank. The facility bears interest at a rate of 6.6% per annum and is due in monthly principal installments of $2.3 million each, ending September 30, 2015. The facility may be prepaid without penalty. The facility is secured by a lien on a hotel owned by Gundem Turizm Yatirim ve Isletme A.S. ("Gundem"), which is 97.5% beneficially owned by Mr. Mitchell. At December 31, 2014, TBNG had balance of $20.0 million under the credit facility and no availability.

Convertible Notes. As of December 31, 2014, we sold $47.4 million of convertible notes in a non-brokered private placement (the "Notes"). The Notes bore interest at a rate of 13.0% per annum and would have matured on July 1, 2017. The Notes were convertible, at the election of a holder, any time after July 1, 2015, into our common shares (the "Common Shares") at a conversion price of $6.80 per share. Subsequent to December 31, 2014, we sold an additional $7.6 million of Notes. On February 20, 2015, the Company exchanged the Notes for substantially identical notes issued pursuant to an indenture (the "Exchange Notes").

Exchange Notes. On February 20, 2015, we issued $55.0 million of Exchange Notes in exchange for all outstanding Notes. The Exchange 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 Exchange Notes bear interest at an annual rate of 13.0%, payable semi-annually, in arrears, on January 1 and July 1 of each year, commencing on July 1, 2015. The Exchange Notes will mature on July 1, 2017, unless earlier redeemed or converted.

Holders may, at any time after July 1, 2015 and from time to time at such holder's option, convert, subject to certain terms and conditions, any or all of the principal of any Exchange Note into fully paid and nonassessable Common Shares at the conversion price. The initial conversion price is $6.80 per Common Share, subject to adjustment as described in the Indenture. Prior to or contemporaneously with the conversion of any of the principal of an Exchange Note, all accrued but unpaid interest on the principal amount being converted will be paid in cash. The Exchange Notes may not be converted into Common Shares on the maturity date or the redemption date.

At any time on or after July 1, 2015, we may redeem all or part of the Exchange Notes at the redemption prices specified below (expressed in percentages of principal amount on the redemption date), plus accrued and unpaid interest to the redemption date.

Period Beginning	Redemption Price
July 1, 2015	107.5%
January 1, 2016	105.0%
July 1, 2016	102.5%
January 1, 2017	100.0%

If we experience a fundamental change (as defined in the Indenture), we will be required to make an offer to repurchase the Exchange Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to but excluding the date of repurchase. Additionally, if we sell certain assets in exchange for $50.0 million or more in cash consideration, in certain circumstances, we will be required to use a portion of the net cash proceeds of such sale to make an offer to repurchase Exchange Notes at a price equal to the price we would be required to pay for an optional redemption at such time, plus accrued and unpaid interest, if any, up to but excluding the date of repurchase. The Indenture provides for customary events of default. The Indenture contains limited covenants.

Term Loan Facility. On September 17, 2014, Stream Sub and Raiffeisen entered into the Term Loan Facility, which amended and restated a facility agreement, dated December 15, 2011, as amended (the “Facility Agreement”). The loan matures on December 31, 2016 and bears interest at the rate of LIBOR plus 5.5%, with a minimum interest rate of 7.0%. Stream Sub is required to pay 1/16th of the total commitment each quarter on the last business day of each of March, June, September and December each year. The loan is guaranteed by Stream Sub's parent company, Stream. Stream Sub may prepay the loan at its option in whole or in part, subject to a 3.0% penalty plus breakage costs. The Term Loan Facility is secured by substantially all of the assets of Stream Sub.

Under the Term Loan Facility, Stream Sub may not declare or pay any dividends on any of Stream Sub's common shares without the consent of the lender, except, provided that no default has occurred and is continuing under the Term Loan Facility, Stream Sub may make payments to Stream from excess cash flow to cover the administrative overhead of Stream, including the salary and related employment costs of any employee, officer or director of Stream, up to a total limit in any three-month period of $500,000.

Pursuant to the terms of the Term Loan Facility, until amounts under the Term Loan Facility are repaid, Stream Sub may not, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of Stream Sub to create any liens, (iii) enter into any amalgamation, demerger, merger, or corporate reconstruction or any joint venture or partnership agreement, (iv) incorporate any company as a subsidiary, (v) dispose of any asset, (vi) declare or pay any dividends to shareholders, (vii) enter into a sale and leaseback arrangement, (viii) make any substantial change to the general nature or scope of its business from that carried on at the date of the Term Loan Facility, (ix) use, deposit, handle, store produce, release or dispose of dangerous materials, (x) make any loans or grant any credit, and (xi) cancel, terminate amend or waive any default under any export contract or allow any buyer to do the same.

In addition, the Term Loan Facility contains financial covenants that require Stream Sub to maintain as of the end of each fiscal year: (i) earnings before interest, taxes, depreciation and amortization ("EBITDA") of not less than $10.0 million; (ii) an outstanding loan principal of no more than twice its EBITDA; and (iii) EBITDA of at least ten times greater than its accrued interest, commission, fees, discounts, prepayment fees, premiums, charges and other finance payments.

An event of default under the Term Loan Facility, includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, upon the occurrence of a change of control of Stream Sub, Stream Sub is required to notify Raiffeisen, and Raiffeisen would have the option to cancel loan commitments and accelerate all outstanding loans and other amounts payable. A change of control is defined under the Term Loan Facility as Stream ceasing to hold more than 75% of the shares in the issued share capital of Stream Sub carrying the right to vote. Our acquisition of Stream did not constitute a change of control under the Term Loan Facility.

Stream must, upon the request of Raiffeisen when Stream Sub's predicted expenditures exceed its predicted revenues for any period, inject cash into Stream by means of equity loan or other method acceptable to Raiffeisen to the extent necessary to remedy the cashflow shortfall or repay the total amount outstanding under the Term Loan Facility.

On September 17, 2014, Stream Sub, Stream and Raiffeisen entered into an amendment and restatement agreement pursuant to which Raiffeisen granted a deferral of the June 2014 principal payment due under the Facility Agreement until December 2016. In addition, Raiffeisen waived its rights under the Facility Agreement with respect to events of default resulting from (i) Stream Sub's non-payment of the June 2014 principal payment; and (ii) Stream Sub's breach of the financial covenants for the fiscal year ended November 30, 2013. Pursuant to the amendment and restatement agreement, (i) Stream Sub paid all fees, costs and expenses due and (ii) Stream Sub and Albpetrol entered into an agreement to postpone certain capital expenditures that were required under Stream's work program on its properties.

As of December 31, 2014, we had $10.5 million outstanding under the Term Loan Facility and no availability.

At December 31, 2014, we were not in compliance with certain conditions subsequent set forth in Section 4 of the Term Loan Facility, including the delivery to Raiffeisen of a copy of an agreement between Albpetrol and ourselves concerning postponement of capital expenditures. Raiffeisen has granted us a waiver on this requirement until May 5, 2015.

Prepayment Agreement. In April 2013, Stream and Stream Sub entered into the prepayment agreement (the "Prepayment Agreement") with Trafigura PTE Ltd ("Trafigura"). In October 2013, Stream received a $7.0 million prepayment under the Prepayment Agreement. No further prepayment requests can be made under the Prepayment Agreement. The prepayment is to be repaid by Stream's delivery of oil to Trafigura in accordance with an oil sales contract between Stream and Trafigura and bears interest at a rate equal to LIBOR plus 6% (6.17% at December 31, 2014). Stream must repay the prepayment at the times and in the quantities as set out in the oil sales contract, and all amounts must be repaid on or before August 31, 2015.

Each of Stream and Stream Sub is required to comply with certain financial and non-financial covenants under the Prepayment Agreement, including financial covenants that Stream must maintain, unless Trafigura agrees otherwise:

(i) EBITDA of not less than $10.0 million;

(ii) outstanding indebtedness of not more than twice its EBITDA; and
(iii) EBITDA of at least ten times greater than its accrued interest, commission, fees, discounts, prepayment fees, premiums, charges and other finance payments.

In addition, Stream must ensure that its coverage ratio is not less than 150% at all times. The coverage ratio is the ratio of the estimated aggregate valuation of the volume of crude oil to be delivered under the oil sales contract between Stream and Trafigura to the outstanding amount of the prepayment plus any applicable funding costs and fees.

Pursuant to the terms of the Prepayment Agreement, until amounts under the Prepayment Agreement are repaid, Stream Sub may not, in each case subject to certain exceptions, (i) create any liens over the Prepayment Agreement, or if such lien would have a material adverse effect, over any other assets or undertakings, (ii) enter into any amalgamation, demerger, merger, or corporate reconstruction, (iii) pay, repay or prepay any principal, interest or other amount on or in respect of or redeem, purchase or cancel any indebtedness owed actually or contingently to any shareholder of Stream Sub or an affiliate of any shareholder of Stream Sub, or (iv) reduce, return, purchase, repay, cancel or redeem any of its share capital.

Trafigura has termination and acceleration rights under the Prepayment Agreement upon the occurrence of certain events, including, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control triggers termination and acceleration rights. A change of control is defined under the Prepayment Agreement as any person or group of persons acting in concert gaining ownership or control of Stream Sub. Control is defined as the power to direct or cause the direction of the management or policies of another person. Trafigura waived the change of control provision under the Prepayment Agreement in connection with our acquisition of Stream.

At December 31, 2014, we had $3.0 million outstanding under the Prepayment Agreement and no availability.

Viking International Note. On September 16, 2014, Stream issued to Viking International Limited (“Viking International”) a note in the principal amount of $6.8 million. The note was amended monthly to evidence additional advances. At December 31, 2014, we had $6.8 million outstanding under the Viking International note. At March 12, 2015, we had repaid the note.

Shareholder Loan. In March 2014, Stream borrowed CAD $3.0 million from a shareholder of Stream. The loan bore interest at a fixed rate of 10.0% per annum, calculated and compounded monthly. On January 6, 2015, we repaid the shareholder loan in full with the net proceeds from our private placement of Notes.

Contractual Obligations

The following table presents a summary of our contractual obligations at December 31, 2014:

	Payments Due By Year (in thousands)						
	Total	2015	2016	2017	2018	2019	Thereafter
Debt	$158,598	$52,606	$73,278	$16,150	$11,764	$4,800	$ -
Interest	26,288	11,077	9,598	4,977	595	41	-
Leases	7,097	2,826	346	195	33	-	3,697
Total	$191,983	$66,509	$83,222	$21,322	$12,392	$4,841	$ 3,697

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements at December 31, 2014.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk from changes in interest rates, foreign currency exchange and hedging contracts. A discussion of the market risk exposures follows. Our market risk sensitive instruments were entered into for hedging and investment purposes, not for trading purposes.

Interest Rate Risk

At December 31, 2014, our exposure to interest rate changes related primarily to floating rate borrowings under our Senior Credit Facility. At December 31, 2014, we had $68.3 million in outstanding borrowings under the Senior Credit Facility. The interest we pay on borrowings under the Senior Credit Facility is equal to three-month LIBOR plus 5.00% per annum (5.26% at December 31, 2014). A hypothetical 10% change in the interest rates we pay on the Senior Credit Facility as of December 31, 2014 would result in an increase or decrease in our interest costs of approximately $0.4 million per year.

Foreign Currency Risk

We are subject to changes in foreign currency exchange rates as a result of our operations in foreign countries. The assets, liabilities and results of operations of our foreign operations are measured using the functional currency of such foreign operation. The functional currency for each of our subsidiaries in Turkey and Bulgaria is the local currency. As a result, translation adjustments will result from the process of translating the functional currency of our foreign operation’s financial statements into the U.S. Dollar reporting currency, which is a non-cash transaction. Such non-cash translation adjustments accumulate on our consolidated balance sheets as a component of accumulated other comprehensive loss and are recorded in our consolidated statements of comprehensive income (loss).

The functional currency of our operations in Turkey and Bulgaria is the TRY and the Bulgarian Lev, respectively. The exchange rates used to translate the financial position of our Turkish and Bulgarian operations at December 31, 2014, 2013 and 2012 are shown below:

	Year Ended December 31,		
	2014	2013	2012
New Turkish Lira per $1.00 U.S Dollar	2.3189	2.1343	1.7826
Bulgarian Lev per $1.00 U.S. Dollar	1.6084	1.4216	1.4827

We are also subject to foreign currency exposures as a result of our operations in the other foreign countries in which we operate. We record foreign exchange (gain) loss on our consolidated statements of comprehensive income (loss) as a component of other (expense) income for gains and losses which result from re-measuring transactions and monetary accounts into our functional currency in earnings. The change in foreign exchange (gain) loss 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. For 2014 and 2013, we recorded a foreign exchange loss of $6.0 million and a foreign exchange loss of $9.7 million, respectively. We estimate that a 10% change in the exchange rates would impact our cash balances and our net loss by approximately $0.5 million. We have not used foreign currency forward contracts to manage exchange rate fluctuations.

Commodity Price Risk

Our revenues are derived from the sale of oil and natural gas. The prices for oil and natural gas are extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supplies, weather conditions, economic conditions and government actions.

Pursuant to our Senior Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with BNP Paribas. As a result, TEMI has entered into costless collar and three-way collar derivative contracts with BNP Paribas to hedge the price of oil. Pursuant to our Senior Credit Facility, we cannot enter into hedge agreements that, when aggregated with any other hydrocarbon hedge agreement then in effect, covers notional volumes in excess of 75% of the reasonably projected production volumes attributable to our proved developed reserves. The derivative contracts economically hedge against the variability in cash flows associated with the forecasted sale of our future oil production. While the use of the hedging arrangements will limit the downside risk of adverse price movements, it may also limit future gains from favorable movements.

The costless collars provide us with a lower limit "floor" price and an upper limit "ceiling" price on the hedged volumes. The floor price represents the lowest price we will receive for the hedged volumes while the ceiling price represents the highest price we will receive for the hedged volumes. The costless collars are settled monthly. These contracts may or may not involve payment or receipt of cash at inception, depending on the ceiling and floor pricing.

The three-way collar contracts consist of a purchased put, a sold call and a purchased call. The purchased put establishes a lower limit "floor" price, the sold call establishes an upper limit "ceiling" price and the purchased call establishes a "second floor" price on the hedged volumes. The three-way collar contracts require our counterparty to pay us if the settlement price for any settlement period is below the floor price. We are required to pay our counterparty if the settlement price for any settlement period is above the ceiling price but below the second floor price, and our counterparty is required to pay us if the settlement price for any settlement period is above the second floor price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price. The three-way collar contracts are settled monthly.

We have elected not to designate our derivative financial instruments as hedges for accounting purposes, and accordingly, we record such contracts at fair value and recognize changes in such fair value in current earnings as they occur. We recognize gains and losses related to these contracts on a mark-to-market basis in our consolidated statements of comprehensive income (loss) under the caption "Loss on commodity derivative contracts." Cash settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows. All of our oil derivative contracts are settled based upon Brent crude oil pricing. If commodity prices decrease, this commodity price change could have a positive impact to our earnings. Conversely, if commodity prices increase, this commodity price change could have a negative effect on our earnings. Each derivative contract is evaluated separately to determine its own fair value. During 2014, we recorded a net gain on commodity derivative contracts of $37.5 million and a net loss of $2.7 million in 2013.

The following tables summarize our outstanding commodity derivatives contracts with respect to our future oil production as of December 31, 2014:

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (in thousands)
Collar	January 1, 2015—December 31, 2015	1,410	$ 85.00	$ 97.25	$ 12,518

			Collars		Additional Call	
Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (in thousands)
Three-way collar contract	January 1, 2016—December 31, 2016	1,066	$ 85.00	$ 97.25	$ 114.25	$ 7,609

Three-way collar contract	January 1, 2017—December 31, 2017	888	$ 85.00	$ 97.25	$ 114.25	5,748
Three-way collar contract	January 1, 2018—December 31, 2018	726	$ 85.00	$ 97.25	$ 114.25	4,659
Three-way collar contract	January 1, 2019—March 31, 2019	663	$ 85.00	$ 97.25	$ 114.25	1,053
						$ 19,069

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

Acquisition of Stream

On November 18, 2014, we acquired Stream. For purposes of determining the effectiveness of our disclosure controls and procedures and internal control over financial reporting as of December 31, 2014, and any change in our internal control over financial reporting for the fourth quarter of 2014, management has excluded the internal control over financial reporting of Stream from its evaluation of these matters. Stream represented approximately $126.6 million or 23.2% of our consolidated total assets at December 31, 2014 and approximately $1.9 million or 1.3% of our consolidated revenue for the year ended December 31, 2014. Any material change to our internal control over financial reporting due to the acquisition of Stream will be disclosed in our Annual Report on Form 10-K for the year ending December 31, 2015 in which our assessment that encompasses Stream will be included.

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, 2014, management carried out an evaluation, under the supervision and with the participation of our chief executive officer and chief financial officer, of the effectiveness of our disclosure controls and procedures. Based upon the evaluation, our chief executive officer and chief financial officer concluded that, as of December 31, 2014, 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 chief 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.

On November 18, 2014, we acquired Stream. For purposes of determining the effectiveness of our internal control over financial reporting as of December 31, 2014, management has excluded the internal control over financial reporting of Stream from its evaluation of these matters. Stream represented approximately $126.6 million or 23.2% of our consolidated total assets at December 31, 2014 and approximately $1.9 million or 1.3% of our consolidated revenue for the year ended December 31, 2014.

Our management, under the supervision and with the participation of our chief executive officer and chief 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 (1992) 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, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements, as stated in their reports on pages F-2 and F-3 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

As of December 31, 2014, management has sufficient evidence to conclude that remediation has been completed for the two material weaknesses which were reported as of December 31, 2013.

There were no additional changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2014 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
   Consolidated Balance Sheets as of December 31, 2014 and 2013
   Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012
   Consolidated Statements of Equity for the years ended December 31, 2014, 2013 and 2012
   Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012
   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.

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 16, 2015

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	Chairman and Chief Executive Officer	March 16, 2015
N. Malone Mitchell 3rd	(Principal Executive Officer)	
/S/ WIL F. SAQUETON	Chief Financial Officer	March 16, 2015
Wil F. Saqueton	(Principal Financial Officer and Principal Accounting Officer/Controller)	
/S/ BOB G. ALEXANDER	Director	March 16, 2015
Bob G. Alexander		
/S/ BRIAN E. BAYLEY	Director	March 16, 2015
Brian Bayley		
/S/ CHARLES J. CAMPISE	Director	March 16, 2015
Charles J. Campise		
/S/ MARLAN W. DOWNEY	Director	March 16, 2015
Marlan W. Downey		
/S/ GREGORY K. RENWICK	Director	March 16, 2015

Gregory K. Renwick

/S/ MEL G. RIGGS	Director	March 16, 2015
Mel G. Riggs		

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

TransAtlantic Petroleum Ltd.:

We have audited the accompanying consolidated balance sheets of TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for each of the years in the three year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAtlantic Petroleum Ltd.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 16, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 16, 2015

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

TransAtlantic Petroleum Ltd.:

We have audited TransAtlantic Petroleum Ltd.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). TransAtlantic Petroleum Ltd.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its 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.

In our opinion, TransAtlantic Petroleum Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

TransAtlantic Petroleum Ltd. acquired Stream Oil & Gas Ltd. during 2014, and management excluded from its assessment of the effectiveness of TransAtlantic Petroleum Ltd.'s internal control over financial reporting as of December 31, 2014, Stream Oil & Gas Ltd.'s internal control over financial reporting associated with total assets of $126.6 million and total revenues of $1.9 million included in the consolidated financial statements of TransAtlantic Petroleum Ltd. and subsidiaries as of and for the year ended December 31, 2014. Our audit of internal control over financial reporting of TransAtlantic Petroleum Ltd. also excluded an evaluation of the internal control over financial reporting of Stream Oil & Gas Ltd.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated March 16, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 16, 2015

TRANSATLANTIC PETROLEUM LTD.

Consolidated Balance Sheets

As of December 31, 2014 and 2013

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

	2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$35,132	$12,881
Accounts receivable, net		
Oil and natural gas sales	29,673	30,619
Joint interest and other	19,918	15,348
Related party	602	1,004
Prepaid and other current assets	8,930	5,072
Deferred income taxes	329	2,239
Derivative asset	12,518	–
Restricted cash	1,917	–
Assets held for sale	28	536
Total current assets	109,047	67,699
Property and equipment		
Oil and natural gas properties (successful efforts methods)		
Proved	424,031	260,857
Unproved	65,438	54,392
Equipment and other property	42,343	39,916
	531,812	355,165
Less accumulated depreciation, depletion and amortization	(141,977)	(104,193)
Property and equipment, net	389,835	250,972
Other long-term assets:		
Other assets	8,836	7,977
Note receivable - related party	11,500	11,500
Derivative asset	19,069	–
Deferred income taxes	1,181	903
Goodwill	6,935	7,535
Total other assets	47,521	27,915
Total assets	$546,403	$346,586
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$39,407	$16,712
Accounts payable - related party	18,488	23,090
Accrued liabilities	31,238	20,658
Deferred income taxes	2,138	–

Derivative liabilities	–	3,737
Asset retirement obligations	323	610
Loans payable	45,806	43,284
Loan payable - related party	6,800	–
Liabilities held for sale	6,928	7,559
Total current liabilities	151,128	115,650
Long-term liabilities:		
Asset retirement obligations	11,053	10,286
Accrued liabilities	12,336	6,487
Deferred income taxes	54,430	16,134
Loans payable	85,192	26,482
Loan payable - related party	20,800	–
Derivative liabilities	–	4,230
Total long-term liabilities	183,811	63,619
Total liabilities	334,939	179,269
Commitments and contingencies		
Shareholders' equity:		
Common shares, $0.10 par value, 100,000,000 shares authorized; 40,708,120 shares and 37,340,206 shares issued and outstanding as of December 31, 2014 and December 31, 2013, respectively	4,071	3,734
Additional paid-in-capital	571,150	542,091
Accumulated other comprehensive loss	(79,310)	(64,985)
Accumulated deficit	(284,447)	(313,523)
Total shareholders' equity	211,464	167,317
Total liabilities and shareholders' equity	$546,403	$346,586

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

TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Comprehensive Income (Loss)

For the years ended December 31, 2014, 2013 and 2012

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

	2014	2013	2012
Revenues:			
Oil and natural gas sales	$138,174	$127,270	$134,113
Sales of purchased natural gas	2,127	2,581	7,882
Other	427	976	1,913
Total revenues	140,728	130,827	143,908
Costs and expenses:			
Production	19,999	18,602	17,804
Transportation costs	284	–	–
Exploration, abandonment and impairment	19,864	27,333	39,993
Cost of purchased natural gas	2,055	2,247	7,694
Seismic and other exploration	4,285	14,009	5,040
Revaluation of contingent consideration	(2,500)	(5,000)	–
General and administrative	31,625	29,020	33,947
Depreciation, depletion and amortization	48,927	41,322	28,215
Accretion of asset retirement obligations	413	508	710
Total costs and expenses	124,952	128,041	133,403
Operating income	15,776	2,786	10,505
Other income (expense):			
Interest and other expense	(6,213)	(3,929)	(8,340)
Interest and other income	1,124	1,340	2,418
Gain (loss) on commodity derivative contracts	37,454	(2,698)	(5,548)
Foreign exchange (loss) gain	(5,998)	(9,663)	1,083
Total other income (expense)	26,367	(14,950)	(10,387)
Income (loss) from continuing operations before income taxes	42,143	(12,164)	118
Current income tax expense	(1,784)	(128)	(4,674)
Deferred income tax expense	(11,263)	(979)	(1,817)
Net income (loss) from continuing operations	29,096	(13,271)	(6,373)
Loss from discontinued operations before income taxes	(20)	(442)	(5,083)
Gain on disposal of discontinued operations	–	–	35,999
Income tax provision	–	–	(8,297)
Net (loss) income from discontinued operations	(20)	(442)	22,619
Net income (loss)	29,076	(13,713)	16,246
Other comprehensive income (loss):			
Foreign currency translation adjustment	(14,325)	(36,973)	22,224
Comprehensive income (loss)	$14,751	$(50,686)	$38,470
Net income (loss) per common share			
Basic net income (loss) per common share			

Continuing operations	$0.77	$(0.36)	$(0.17)
Discontinued operations	$–	$(0.01)	$0.62
Weighted average common shares outstanding	37,829	37,069	36,742
Diluted net income (loss) per common share			
Continuing operations	$0.77	$(0.36)	$(0.17)
Discontinued operations	$–	$(0.01)	$0.62
Weighted average common and common equivalent shares outstanding	38,031	37,069	36,742

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, 2014, 2013 and 2012

(U.S. Dollars and shares in thousands)

	Common Shares	Warrants	Common Shares (at par)	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Shareholders' Equity
Balances at December 31, 2011	36,579	–	$ 3,658	$ 533,907	$ (50,236)	$ (316,056)	$ 171,273
Exercise of share options	81	–	8	656	–	–	664
Issuance of restricted stock units	215	–	21	(21)	–	–	–
Tax withholding on restricted stock units	–	–	–	(147)	–	–	(147)
Share-based compensation	–	–	–	3,567	–	–	3,567
Foreign currency translation adjustment	–	–	–	–	22,224	–	22,224
Net income	–	–	–	–	–	16,246	16,246
Balances at December 31, 2012	36,875	–	3,687	537,962	(28,012)	(299,810)	213,827
Issuance of common shares	351	–	35	2,465	–	–	2,500
Issuance of restricted stock units	114	–	12	(12)	–	–	–
Tax withholding on restricted stock units	–	–	–	(40)	–	–	(40)
Share-based compensation	–	–	–	1,716	–	–	1,716
Foreign currency translation adjustment	–	–	–	–	(36,973)	–	(36,973)
Net loss	–	–	–	–	–	(13,713)	(13,713)
Balances at December 31, 2013	37,340	–	3,734	542,091	(64,985)	(313,523)	167,317
Issuance of common shares	3,219	–	322	23,528	–	–	23,850
Contingent payment event	–	–	–	4,188	–	–	4,188
Issuance of warrants	–	233	–	–	–	–	–
Issuance of restricted stock units	149	–	15	(15)	–	–	–

Tax withholding on restricted stock units	–	–	–	(76)	–	–	(76)
Share-based compensation	–	–	–	1,434	–	–	1,434
Foreign currency translation adjustment	–	–	–	–	(14,325)	–	(14,325)
Net income	–	–	–	–	–	29,076	29,076
Balances at December 31, 2014	40,708	233	$ 4,071	$ 571,150	$ (79,310)	$ (284,447)	$ 211,464

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, 2014, 2013 and 2012

(in thousands of U.S. Dollars)

	2014	2013	2012
Operating activities:			
Net income (loss)	$29,076	$(13,713)	$16,246
Adjustment for net loss (income) from discontinued operations	20	442	(22,619)
Net income (loss) from continuing operations	29,096	(13,271)	(6,373)
Adjustments to reconcile net income to net cash provided by operating activities:			
Share-based compensation	1,434	1,716	2,559
Foreign currency loss	6,785	8,620	3,843
(Gain) loss on commodity derivative contracts	(37,454)	2,698	5,548
Cash settlement on commodity derivative contracts	(2,100)	(3,521)	(3,829)
Amortization on loan financing costs	1,025	510	1,991
Bad debt expense	1,487	–	–
Deferred income tax expense	11,263	979	1,817
Inventory write down	–	–	1,390
Exploration, abandonment and impairment	19,864	27,333	39,993
Depreciation, depletion and amortization	48,927	41,322	28,215
Accretion of asset retirement obligations	413	508	710
Revaluation of contingency consideration	(2,500)	(5,000)	–
Changes in operating assets and liabilities:			
Accounts receivable	(3,690)	(2,353)	(6,872)
Prepaid expenses and other assets	(1,718)	(34)	(1,149)
Accounts payable and accrued liabilities	5,282	9,269	1,503
Net cash provided by operating activities of continuing operations	78,114	68,776	69,346
Net cash used in operating activities of discontinued operations	(62)	(1,426)	(25,769)
Net cash provided by operating activities	78,052	67,350	43,577
Investing activities:			
Acquisitions, net of cash	66	–	–
Additions to oil and natural gas properties	(109,027)	(94,266)	(70,189)
Additions to equipment and other properties	(6,318)	(10,653)	(668)
Restricted cash	(1,917)	(190)	949
Net cash used in investing activities of continuing operations	(117,196)	(105,109)	(69,908)
Net cash provided by investing activities of discontinued operations	500	1,016	156,149
Net cash (used in) provided by investing activities	(116,696)	(104,093)	86,241
Financing activities:			
Exercise of stock options	–	–	664
Tax withholding on restricted share units	(76)	(40)	(147)

Loan proceeds	73,237	66,785	25,967
Loan proceeds - related party	20,800	–	11,000
Loan repayment	(29,770)	(29,785)	(78,931)
Loan repayment - related party	-	–	(84,000)
Loan financing costs	(2,630)	–	(250)
Net cash provided by (used in) financing activities from continuing operations	61,561	36,960	(125,697)
Net cash used in financing activities from discontinued operations	–	–	(5,049)
Net cash provided by (used in) financing activities	61,561	36,960	(130,746)
Effect of exchange rate on cash flows and cash equivalents	(666)	(2,104)	580
Net increase (decrease) in cash and cash equivalents	22,251	(1,887)	(348)
Cash and cash equivalents, beginning of year	12,881	14,768	15,116
Cash and cash equivalents, end of year	$35,132	$12,881	$14,768
Supplemental disclosures:			
Cash paid for interest	$3,490	$3,091	$6,946
Cash paid for taxes	$–	$2,387	$5,596
Supplemental non-cash financing activities:			
Issuance of common shares for acquisition	$23,850	$–	$–
Contingent payment event	$4,188	$–	$–
Note receivable - related party from sale of oilfield services business	$–	$–	$11,500
Issuance of common shares - amendment to purchase agreement	$–	$2,500	$–

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

TRANSATLANTIC PETROLEUM LTD.

Notes to 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, 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, 2014, we held interests in developed and undeveloped oil and natural gas properties in Turkey, Albania and Bulgaria. As of March 1, 2015, approximately 36% of our outstanding common shares were beneficially owned by N. Malone Mitchell 3rd, our chief executive officer and chairman of our board of directors.

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 and financial derivatives, the recoverability and impairment of long-lived assets and goodwill, contingencies and income taxes. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Oil Price Decline

As a result of the recent decline in prices for Brent crude, we have reduced our planned capital expenditures and deferred a significant amount of our planned exploration and development until prices for Brent crude improve. In order to mitigate the impact of reduced prices on our 2015 cash flows and liquidity, we have implemented cost reduction measures and will continue to implement cost-cutting initiatives to reduce our operating costs and general and administrative expenses. These initiatives include the negotiation of exploration and development and operating cost reductions with several key vendors and plans to continue to pursue further reductions. We believe this strategy will allow us to preserve our liquidity in order to execute our 2015 development program and continue to meet our contractual obligations.

We believe that our cash flows from operations and existing cash on hand are sufficient to conduct our planned operations through 2015 and meet our contractual requirements, including license obligations. Additionally, at current Brent crude prices, our current hedge positions provide additional liquidity on a monthly recurring basis.

Notwithstanding these measures, there remain risks and uncertainties that could negatively impact our results of operations and financial condition. For example, reductions in our borrowing capacity as a result of a redetermination to our borrowing base could have an impact on our capital resources and liquidity. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices.

2. 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. During the year ended December 31, 2014, we reclassified certain balance sheet amounts previously reported on our consolidated balance sheet at December 31, 2013 to conform to current year presentation.

Reverse stock split

On March 4, 2014, the Company's shareholders approved a 1-for-10 reverse stock split, which became effective March 6, 2014. Pursuant to the reverse stock split, all shareholders of record received one common share for each ten common shares owned (subject to minor adjustments as a result of fractional shares). The reverse stock split reduced the issued and outstanding common shares from 374,026,984 to 37,402,698. U.S. GAAP requires that the reverse stock split be applied retrospectively to all periods presented. As a result, all common share transactions described herein have been adjusted to reflect the 1-for-10 reverse stock split.

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.

Commodity 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, Bulgaria, Romania, Morocco, and Albania is the New Turkish Lira (“TRY”), the Bulgarian Lev, the Romanian New Leu, the Moroccan Dirham, and the U.S. Dollar (“USD”) 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 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) the Company’s history in exploring the area, (iii) the Company’s future drilling plans per its capital drilling program prepared by the Company’s 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.

Goodwill

In accordance with ASC 350, Intangibles-Goodwill and Other ("ASC 350"), goodwill is not amortized, but is tested for impairment on an annual basis at December 31, or more frequently as impairment indicators arise. ASC 350 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. We assessed the qualitative factors at December 31, 2014 and, based upon the results of the qualitative assessment, we determined that it was not necessary to perform the two-step goodwill impairment test and that our goodwill was not impaired. All of our goodwill is attributable to our Turkey operating segment.

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

Revenue from the sale of crude oil and natural gas is recognized upon delivery to the purchaser when title passes. During the years ended December 31, 2014, 2013 and 2012, we sold $102.8 million, $87.2 million and $91.8 million, respectively, of oil to Türkiye Petrol Rafinerileri A.Ş. ("TUPRAS"), a privately owned oil refinery in Turkey, which represented approximately 73.0%, 66.7% and 63.8% 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.

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 bases. 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.

In connection with our acquisition Amity Oil International Pty Ltd ("Amity") and Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş. ("Petrogas") in August 2010, at December 31, 2012, we recognized a liability due to an uncertain tax position related to the transfer of Petrogas shares to Amity prior to the acquisition (see Note 11). 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

ASC 220, Comprehensive Income, 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 810-10-65”). 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. See Note 4.

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.

3. New accounting pronouncements

In April 2014, the Financial Accounting Standard Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-08, Reporting Discontinued Operations and Disclosures of Components of an Entity (“ASU 2014-08”). ASU 2014-08 revises the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have (or will have) a major effect on an entity’s operations and financial results, removing the lack of continuing involvement criteria and requiring discontinued operations reporting for the disposal of an equity method investment that meets the definition of discontinued operations. The update also requires expanded disclosures for discontinued operations, including disclosure of pretax profit or loss of an individually significant component of an entity that does not qualify for discontinued operations reporting. The update is effective prospectively to all periods beginning after December 15, 2014. Currently, we do not expect the adoption of ASU 2014-08 to have a material impact on our consolidated financial statements or results of operations.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). ASU 2014-09 amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods or services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The update is effective for periods beginning after December 15, 2016. We are currently assessing the potential impact of ASU 2014-09 on our consolidated financial statements and results of operations.

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"), an amendment to FASB Accounting Standards Codification ("ASC") Topic 205, Presentation of Financial Statements. This update provides guidance on management's responsibility in evaluating whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. We do not expect the adoption of ASU 2014-15 to have a material impact on our consolidated financial statements or results of operations. If events occur in future periods that affect our ability to continue as a going concern, we will provide the disclosures required by ASU 2014-15.

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.

4. Acquisitions

Stream

On November 18, 2014, we acquired Stream Oil & Gas Ltd. ("Stream") in exchange for (i) 3.2 million of our common shares of the Company issued at closing, and (ii) an additional 0.6 million of our common shares issuable if certain conditions are met (at a deemed price of $7.41 per common share). We engaged independent valuation experts to assist in the determination of the fair value of the assets and liabilities acquired in the acquisition. We are still assessing the assets acquired and liabilities assumed, thus the final determination of the value of assets acquired and liabilities assumed may result in adjustments to the values presented below. The following tables summarize the consideration paid in the acquisition and the preliminary amounts of assets acquired and liabilities assumed that have been recognized at the acquisition date:

	(in thousands)
Consideration:	
Issuance of 3,218,641 common shares	$ 23,850
Contingent payment event	4,188
Fair value of total consideration	$ 28,038
Acquisition-Related Costs:	
Included in general and administrative expenses on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2014	$ 1,129
Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed at Acquisition:	
Assets:	
Cash	$ 66
Accounts receivable	6,672
Other current assets	347
Total current assets	7,085
Oil and natural gas properties:	
Proved properties	99,927
Unproved properties	16,140
Equipment and other property	964
Total oil and natural gas properties and other equipment	117,031
Total assets	124,116
Liabilities:	
Accounts payable	20,673
Accounts payable - related party	2,820
Other current liabilities	10,000
Viking International note - related party	6,800
Loans payable - current	11,732
Other non-current liabilities	5,036
Loans payable - non-current	6,123
Asset retirement obligations	827
Deferred income taxes	32,067

Total liabilities	96,078
Total identifiable net assets	$ 28,038

The results of operations of Stream are included in our consolidated statement of comprehensive income (loss) beginning November 18, 2014. The revenues and expenses of Stream included in our consolidated statement of comprehensive income (loss) for the year ended December 31, 2014 were:

	Revenue	Loss
	(in thousands)	
Actual from November 18, 2014 through December 31, 2014	$ 1,898	$ (118)

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Pro forma results of operations

The following table presents the unaudited pro forma results of operations for the year ended December 31, 2014 and 2013 as though the acquisition of Stream had occurred at January 1, 2013 (in thousands, except per share amounts):

	2014	2013
Total revenues	$160,021	$153,794
Income (loss) from continuing operations before income taxes	45,166	(15,118)
Income (loss) from continuing operations	32,467	(19,435)
Loss from discontinued operations	(20)	(442)
Net income (loss)	32,447	(19,877)
Net loss per common share from continuing operations		
Basic and diluted	$0.80	$(0.48)
Net loss per common share from discontinued operations		
Basic and diluted	$-	$(0.01)

5. Goodwill

Goodwill represents the excess of the purchase price of a business over the estimated fair value of the assets acquired and liabilities assumed. We have goodwill on acquisitions where we anticipated access to potential exploration and producing opportunities. All of our goodwill is attributable to our Turkey operating segment. Goodwill was as follows at December 31, 2014 and 2013:

	2014	2013
	(in thousands)	
Goodwill at January 1,	$7,535	$9,021
Foreign exchange effect	(600)	(1,486)
Goodwill at December 31	$6,935	$7,535

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:

	2014	2013
	(in thousands)	
Oil and natural gas properties, proved:		
Turkey	$323,442	$260,232
Albania	100,037	–
Bulgaria	552	625
Total oil and natural gas properties, proved	424,031	260,857
Oil and natural gas properties, unproved:		
Turkey	43,090	51,273
Albania	18,301	–
Bulgaria	4,047	3,119
Total oil and natural gas properties, unproved	65,438	54,392
Gross oil and natural gas properties	489,469	315,249
Accumulated depletion	(133,304)	(96,958)
Net oil and natural gas properties	$356,165	$218,291

At December 31, 2014 and 2013, we excluded $0.9million and $1.5 million of costs, respectively, from the depletion calculation for development wells in progress and for costs on fields currently not in production.

At December 31, 2014, the capitalized costs of our oil and natural gas properties included $129.0 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and $160.8 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, 2013, the capitalized costs of our oil and natural gas properties included $35.5 million relating to acquisition costs of proved properties, which are being amortized by the unit-of-production method using total proved reserves, and $126.9 million relating to well costs, and additional development costs, which are being amortized by the unit-of-production method using proved developed reserves.

Dry hole costs

During the years ended December 31, 2014, 2013 and 2012, we recorded $0.5 million, $16.0 million, and $24.7 million of exploratory dry hole costs, respectively. Of the $0.5 million of dry hole costs incurred during the year ended December 31, 2014, approximately $0.3 million was related to cash spent during 2014.

Impairment and abandonment

Unproved oil and natural gas properties that are individually significant are periodically assessed for impairment, and a loss is recognized at the time of impairment. Capitalized costs related to proved oil and natural gas properties, including wells and related equipment and facilities, are evaluated for impairment based on our analysis of undiscounted future net cash flows. If undiscounted future net cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income equal to the difference between the carrying value and the estimated fair value of the properties. We categorize the measurement of fair value of these assets as Level 3 inputs. Estimated fair values are determined using discounted cash flow models. The discounted cash flow models include management's estimates of future oil and natural gas production, operating and development costs, and discount rates.

During the year ended December 31, 2014, we recorded $19.4 million in impairment and abandonment charges on our proved and unproved properties. Of the $19.4 million, approximately $13.8 million relates to unproved exploratory well impairment on the following wells: $3.5 million related to impairment on the Catak-1 well, $2.8 million related to the Kazanci-5 well, and $7.5 million related to the Bahar-2 side track well.

During the year ended December 31, 2013, we recorded $11.3 million in impairment and abandonment charges on our proved and unproved properties, primarily related to our Senova and Malkara licenses.

During the year ended December 31, 2012, we recorded $6.7 million in impairment charges on our proved properties, of which $2.7 million was due to downward revisions in natural gas reserves in our Alpullu field. We recorded a $8.4 million impairment on our unproved oil and natural gas properties during the year ended December 31, 2012. Of this amount, $5.2 million was attributable to exploration license acquisition costs for the Banarli license.

Capitalized cost greater than one year

As of December 31, 2014, we had $1.6 million of exploratory well costs capitalized for the Hayrabolu-10 well in Turkey, which we spud in February 2013. The Hayrabolu-10 well continues to be evaluated for completion pending more analysis and comparable well results. Additionally, we have $4.0 million of exploratory well costs for the Deventci-R2 well in Bulgaria, which we spud in October 2013, and we are currently still evaluating the results of an acid stimulation.

Equipment and other property

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

	2014	2013
	(in thousands)	
Other equipment	$3,035	$2,678
Inventory	24,309	24,318
Gas gathering system and facilities	4,128	4,485
Vehicles	536	321
Leasehold improvements, office equipment and software	10,335	8,114
Gross equipment and other property	42,343	39,916
Accumulated depreciation	(8,673)	(7,235)
Net equipment and other property	$33,670	$32,681

We classify our materials and supply inventory, including steel tubing and casing, 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, 2014, we excluded $24.3 million of inventory and $3.0 million of software from depreciation, as the inventory and software had not been placed into service. At December 31, 2013, we excluded $24.3 million of inventory and $0.7 million of software from depreciation as the inventory had not been placed into service.

7. Commodity derivative instruments

We use collar derivative contracts to economically hedge against the variability in cash flows associated with the forecasted sale of a portion of our future oil production. 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.

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 income (loss) under the caption “Gain (loss) on commodity derivative contracts.” Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows under the caption “Cash settlement on commodity derivative contracts.” We are required under our senior credit facility (the “Senior Credit Facility”) with BNP Paribas (Suisse) SA (“BNP Paribas”) and the International Finance Corporation (“IFC”), to hedge between 30% and 75% of our anticipated production volumes in Turkey.

During the years ended December 31, 2014, 2013 and 2012, we recorded a net gain on commodity derivative contracts of $37.5 million, a net loss of $2.7 million and $5.5 million, respectively.

At December 31, 2014, 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, 2014

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (in thousands)
Collar	January 1, 2015—December 31, 2015	1,410	$ 85.00	$ 97.25	$ 12,518

Collars		Additional Call
Weighted Average	Weighted Average	Weighted Average

Type	Period	Quantity (Bbl/day)	Minimum Price (per Bbl)	Maximum Price (per Bbl)	Maximum Price (per Bbl)	Estimated Fair Value of Asset (in thousands)
Three-way collar contract	January 1, 2016—December 31, 2016	1,066	$ 85.00	$ 97.25	$ 114.25	$ 7,609
Three-way collar contract	January 1, 2017—December 31, 2017	888	$ 85.00	$ 97.25	$ 114.25	5,748
Three-way collar contract	January 1, 2018—December 31, 2018	726	$ 85.00	$ 97.25	$ 114.25	4,659
Three-way collar contract	January 1, 2019—March 31, 2019	663	$ 85.00	$ 97.25	$ 114.25	1,053
						$ 19,069

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At December 31, 2013, 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, 2013

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Collar	January 1, 2014—December 31, 2014	622	$ 80.83	$ 118.07	$ (387)
					$ (387)

Type	Period	Quantity (Bbl/day)	Collars: Weighted Average Minimum Price (per Bbl)	Collars: Weighted Average Maximum Price (per Bbl)	Additional Call: Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Liability (in thousands)
Three-way collar contract	January 1, 2014—December 31, 2014	726	$ 85.00	$ 97.13	$ 162.13	$ (3,350)
Three-way collar contract	January 1, 2015—December 31, 2015	1,016	$ 85.00	$ 91.88	$ 151.88	(4,230)
						$ (7,580)

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, 2014 and December 31, 2013, and (ii) the net recorded fair value as reflected on our consolidated balance sheets at December 31, 2014 and December 31, 2013.

		As of December 31, 2014		
Underlying Commodity	Location on Balance Sheet	Gross Amount of Recognized Assets	Gross Amount Offset in the Consolidated Balance Sheet	Net Amount of Assets Presented in the Consolidated Balance Sheet
		(in thousands)		
Crude oil	Current Assets	$12,518	$ –	$ 12,518
Crude oil	Long-term Assets	19,069	–	19,069

		As of December 31, 2013		
Underlying Commodity	Location on Balance Sheet	Gross Amount of Recognized Liabilities	Gross Amount Offset in the Consolidated Balance Sheet	Net Amount of Liabilities Presented in the Consolidated Balance Sheet
		(in thousands)		
Crude oil	Current liabilities	$3,737	$ –	$ 3,737
Crude oil	Long-term liabilities	4,230	–	4,230

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, 2014, the net present value of our total ARO was estimated to be $11.4 million, with the undiscounted value being $29.8 million. Total ARO at December 31, 2014 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 6.6% per annum for Turkey, 1.4% for Bulgaria, and 1.6% for Albania. These values are discounted to present value using our credit-adjusted risk-free rate for Turkey of 5.3%, Albania of 7.0% and Bulgaria of 5.3% per annum for the years ended December 31, 2014 and 2013. The following table summarizes the changes in our ARO for the years ended December 31, 2014 and 2013:

	2014	2013
	(in thousands)	
Asset retirement obligations at beginning of period	$10,896	$11,958
Change in estimates	–	(7)
Liabilities settled	(373)	(296)
Foreign exchange change effect	(900)	(2,258)
Additions	513	991
Accretion expense	413	508
Acquisitions	827	–
Asset retirement obligations at end of period	11,376	10,896
Less: current portion	323	610
Long-term portion	$11,053	$10,286

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:

	2014	2013
Fixed and floating rate loans	(in thousands)	
Senior Credit Facility	$68,298	$–
Amended and Restated Credit Facility	–	49,766
Convertible notes	26,600	–
Convertible notes - related party	20,800	–
TBNG credit facility	20,025	20,000

Term Loan Facility	10,452	–
Viking International note - related party	6,800	–
Prepayment Agreement	3,043	–
Shareholder loan	2,580	–
Loans payable	158,598	69,766
Less: current portion	52,606	43,284
Long-term portion	$105,992	$26,482

Amended and Restated Credit Facility

On May 18, 2011, DMLP, Ltd. ("DMLP"), TransAtlantic Exploration Mediterranean International Pty Ltd ("TEMI"), Talon Exploration, Ltd. ("Talon Exploration"), TransAtlantic Turkey, Ltd. ("TransAtlantic Turkey") and Petrogas (collectively, and together with Amity, the "Borrowers") entered into an amended and restated credit facility (the "Amended and Restated Credit Facility") with Standard Bank Plc and BNP Paribas. Each of the Borrowers is our wholly owned subsidiary. In July 2011, Amity executed a joinder agreement and became a borrower under the Amended and Restated Credit Facility. The Amended and Restated Credit Facility was guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide, Ltd. ("TransAtlantic Worldwide"). On May 6, 2014, we entered into the new Senior Credit Facility, and on May 15, 2014, we repaid the Amended and Restated Credit Facility in full and it was terminated.

Senior Credit Facility

On May 6, 2014, the Borrowers entered into the Senior Credit Facility with BNP Paribas and IFC. Each of the Borrowers is our wholly owned subsidiary. The Senior Credit Facility is guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide (each, a “Guarantor”).

The amount drawn under the Senior Credit Facility may not exceed the lesser of (i) $150.0 million, (ii) the borrowing base amount at such time, (iii) the aggregate commitments of all lenders at such time, and (iv) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender’s individual commitment. The lenders have an initial aggregate commitment of $80.0 million, with individual commitments of $40.0 million each. The Company has the ability to increase the commitments up to an aggregate of $150.0 million by March 31, 2016. On the first day of each fiscal quarter commencing April 1, 2016, the lenders’ commitments are subject to reduction in an amount equal to 7.69% of the aggregate commitments in effect on April 1, 2016.

The borrowing base amount is re-determined semi-annually on April 1st and October 1st of each year, beginning April 1, 2015. The borrowing base was $71.5 million as of December 31, 2014. The borrowing base amount equals, for any calculation date, the lowest of:

- the debt value which results in the field life coverage ratio for such calculation date being 1.50 to 1.00; and
- the debt value which results in the loan life coverage ratio for such calculation date being 1.30 to 1.00.

The Senior Credit Facility matures on the earlier of (i) March 31, 2019, or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual banking case of BNP Paribas and the Borrowers determines that the aggregate amount of hydrocarbons to be produced from the borrowing base assets in Turkey are less than 25% of the amount of hydrocarbons to be produced from the borrowing base assets shown in the initial banking case prepared by BNP Paribas and the Borrowers. The Senior Credit Facility bears various letter of credit sub-limits, including among other things, sub-limits of up to (i) $10.0 million, (ii) the aggregate available unused and uncancelled portion of the lenders’ commitments or (iii) any amount borrowed from an individual lender to the extent it exceeds the aggregate amount of such lender’s individual commitment.

Loans under the Senior Credit Facility accrue interest at a rate of three-month LIBOR plus 5.00% per annum (5.26% at December 31, 2014). The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.00% per annum of the unused and uncancelled portion of the aggregate commitments that is less than or equal to the maximum available amount under the Senior Credit Facility, and (b) 1.00% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Senior Credit Facility and is not available to be borrowed, (ii) on the date of issuance of any letter of credit, a fronting fee in an amount equal to 0.25% of the original maximum amount to be drawn under such letter of credit and (iii) a per annum letter of credit fee for each letter of credit issued equal to the face amount of such letter of credit multiplied by (a) 1.0% for any letter of credit that is cash collateralized or backed by a standby letter of credit issued by a financial institution acceptable to BNP Paribas or (b) 5.00% for all other letters of credit.

The Senior Credit Facility is secured by a pledge of (i) the local collection accounts and offshore collection accounts of each of the Borrowers, (ii) the receivables payable to each of the Borrowers, (iii) the shares of each Borrower and (iv) substantially all of the present and future assets of the Borrowers.

The Borrowers are required to comply with certain financial and non-financial covenants under the Senior Credit Facility, including maintaining the following financial ratios during the four most recently completed fiscal quarters occurring on or after March 31, 2014:

- ratio of combined current assets to combined current liabilities of not less than 1.10 to 1.00;

- ratio of EBITDAX (less non-discretionary capital expenditures) to aggregate amounts payable under the Senior Credit Facility of not less than 1.50 to 1.00;
- ratio of EBITDAX (less non-discretionary capital expenditures) to interest expense of not less than 4.00 to 1.00; and
- ratio of total debt to EBITDAX of less than 2.50 to 1.00.

The Senior Credit Facility defines EBITDAX as net income (excluding extraordinary items) plus, to the extent deducted in calculating such net income, (i) interest expense (excluding interest paid-in-kind, or non-cash interest expense and interest incurred on certain subordinated intercompany debt or interest on equity recapitalized into subordinated debt), (ii) income tax expense, (iii) depreciation, depletion and amortization expense, (iv) amortization of intangibles and organization costs, (v) any extraordinary, unusual or non-recurring non-cash expenses or losses, (vi) any other non-cash charges (including dry hole expenses and seismic expenses, to the extent such expenses would be capitalized under the "full cost" accounting method), (vii) expenses incurred in connection with oil and gas exploration activities entered into in the ordinary course of business (including related drilling, completion, geological and geophysical costs), and (viii) transaction costs, expenses and fees incurred in connection with the negotiation, execution and delivery of the Senior Credit Facility and the related loan documents, minus, to the extent included in calculating net income, (a) any extraordinary, unusual or non-recurring income or gains (including, gains on the sales of assets outside of the ordinary course of business) and (b) any other non-cash income or gains.

Pursuant to the terms of the Senior Credit Facility, until amounts under the Senior Credit Facility are repaid, each of the Borrowers shall not, and shall cause each of its subsidiaries not to, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of any Borrower or its subsidiaries to create any liens, (iii) enter into any merger, consolidation or amalgamation, liquidate or dissolve, (iv) dispose of any property or business, (v) pay any dividends, distributions or similar payments to shareholders, (vi) make certain types of investments, (vii) enter into any transactions with an affiliate, (viii) enter into a sale and leaseback arrangement, (ix) engage in any business or business activity, own any assets or assume any liabilities or obligations except as necessary in connection with, or reasonably related to, its business as an oil and natural gas exploration and production company or operate or carry on business in any jurisdiction outside of Turkey or its jurisdiction of formation, (x) change its organizational documents, (xi) permit its fiscal year to end on a day other than December 31st or change its method of determining fiscal quarters, or alter the accounting principles it uses, (xii) modify certain hydrocarbon licenses and agreements or material contracts, (xiii) enter into any hedge agreement for speculative purposes, (xiv) open or maintain new deposit, securities or commodity accounts, (xv) use the proceeds from any loan in the territories of any country that is not a member of the World Bank, (xvi) incur any expenditure that is not covered by the projections in the most recent corporate cashflow projection, (xvii) modify its social and environmental action plans as determined in conjunction with IFC, (xviii) enter into any transaction or engage in any activity prohibited by the United Nations Security Council, or (xix) engage in any corrupt, fraudulent, coercive, collusive or obstructive practice.

An event of default under the Senior Credit Facility includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control is an event of default. A change of control is defined as the occurrence of any of the following: (i) our failure to own, of record and beneficially, all of the equity of the Borrowers or any Guarantor or to exercise, directly or indirectly, day-to-day management and operational control of any Borrower or Guarantor; (ii) the failure by the Borrowers to own or hold, directly or indirectly, all of the interests granted to Borrowers pursuant to certain hydrocarbon licenses designated in the Senior Credit Facility; or (iii) (a) Mr. Mitchell ceases for any reason to be the executive chairman of our board of directors at any time, (b) Mr. Mitchell and certain of his affiliates cease to own of record and beneficially at least 35% of our common shares; or (c) any person or group, excluding Mr. Mitchell and certain of his affiliates, shall become, or obtain rights to become, the beneficial owner, directly or indirectly, of more than 35% of our outstanding common shares entitled to vote for members of our board of directors on a fully-diluted basis; provided, that, if Mr. Mitchell ceases to be executive chairman of our board of directors by reason of his death or disability, such event shall not constitute an event of default unless we have not appointed a successor reasonably acceptable to the lenders within 60 days of the occurrence of such event.

Pursuant to the Senior Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with BNP Paribas that hedge between 30% and 75% of our anticipated oil production volumes in our oil fields in Turkey. TEMI has entered into three-way collar contracts with BNP Paribas, which hedge the price of oil through March 2019. As of December 31, 2014, we had outstanding borrowings of $68.3 million and $3.2 million of remaining availability under the Senior Credit Facility.

At December 31, 2014, we were not in compliance with Section 8.16(a) of our Senior Credit Facility, which requires the Borrowers to maintain a current ratio of not less than 1.10:1.0. The lenders have granted the Borrowers a waiver on the current ratio requirement through March 31, 2015.

Convertible notes

As of December 31, 2014, we sold $47.4 million of convertible notes in a non-brokered private placement (the “Notes”). The Notes bore interest at a rate of 13.0% per annum and would have matured on July 1, 2017. The Notes were convertible, at the election of a holder, any time after July 1, 2015, into our common shares (the “Common Shares”) at a conversion price of $6.80 per share. Subsequent to December 31, 2014, we sold an additional $7.6 million of Notes. On February 20, 2015, we exchanged the Notes for substantially identical notes issued pursuant to an indenture (the “Exchange Notes”). See Note 16 – Subsequent Events.

TBNG credit facility

Thrace Basin Natural Gas (Turkiye) Corporation (“TBNG”) has a fully drawn credit facility with a Turkish bank. The facility bears interest at a rate of 6.6% per annum and is due in monthly principal installments of $2.3 million each, ending September 30, 2015. The facility may be prepaid without penalty. The facility is secured by a lien on a hotel owned by Gundem Turizm Yatirim ve Isletme A.S. (“Gundem”), which is 97.5% beneficially owned by Mr. Mitchell and his children. At December 31, 2014, TBNG had a balance of $20.0 million under the credit facility and no availability.

Term Loan Facility

On September 17, 2014, Stream Oil & Gas Ltd., a Cayman Islands corporation (“Stream Sub”) and Raiffeisen Bank Sh.A (“Raiffeisen”) entered into the term loan facility (the “Term Loan Facility”), which amended and restated a facility agreement, dated December 15, 2011, as amended (the “Facility Agreement”). The loan matures on December 31, 2016 and bears interest at the rate of LIBOR plus 5.5%, with a minimum interest rate of 7.0%. Stream Sub is required to pay 1/16th of the total commitment each quarter on the last business day of each of March, June, September and December each year. The loan is guaranteed by Stream Sub’s parent company, Stream. Stream Sub may prepay the loan at its option in whole or in part, subject to a 3.0% penalty plus breakage costs. The Term Loan Facility is secured by substantially all of the assets of Stream Sub.

Under the Term Loan Facility, Stream Sub may not declare or pay any dividends on any of Stream Sub’s common shares without the consent of the lender, except, provided that no default has occurred and is continuing under the Term Loan Facility, Stream Sub may make payments to Stream from excess cash flow to cover the administrative overhead of Stream, including the salary and related employment costs of any employee, officer or director of Stream, up to a total limit in any three-month period of $500,000.

Pursuant to the terms of the Term Loan Facility, until amounts under the Term Loan Facility are repaid, Stream Sub may not, in each case subject to certain exceptions (i) incur indebtedness or create any liens, (ii) enter into any agreements that prohibit the ability of Stream Sub to create any liens, (iii) enter into any amalgamation, demerger, merger, or corporate reconstruction or any joint venture or partnership agreement, (iv) incorporate any company as a subsidiary, (v) dispose of any asset, (vi) declare or pay any dividends to shareholders, (vii) enter into a sale and leaseback arrangement, (viii) make any substantial change to the general nature or scope of its business from that carried on at the date of the Term Loan Facility, (ix) use, deposit, handle, store produce, release or dispose of dangerous materials, (x) make any loans or grant any credit, and (xi) cancel, terminate amend or waive any default under any export contract or allow any buyer to do the same.

In addition, the Term Loan Facility contains financial covenants that require Stream Sub to maintain as of the end of each fiscal year: (i) earnings before interest, taxes, depreciation and amortization (“EBITDA”) of not less than $10.0 million; (ii) an outstanding loan principal of no more than twice its EBITDA; and (iii) EBITDA of at least ten times greater than its accrued interest, commission, fees, discounts, prepayment fees, premiums, charges and other finance payments.

An event of default under the Term Loan Facility, includes, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, upon the occurrence of a change of control of Stream Sub, Stream Sub is required to notify Raiffeisen, and Raiffeisen would have the option to cancel loan commitments and accelerate all outstanding loans and other amounts payable. A change of control is defined under the Term Loan Facility as Stream ceasing to hold more than 75% of the shares in the issued share capital of Stream Sub carrying the right to vote. Our acquisition of Stream did not constitute a change of control under the Term Loan Facility.

Stream must, upon the request of Raiffeisen when Stream Sub's predicted expenditures exceed its predicted revenues for any period, inject cash into Stream by means of equity loan or other method acceptable to Raiffeisen to the extent necessary to remedy the cashflow shortfall or repay the total amount outstanding under the Term Loan Facility.

On September 17, 2014, Stream Sub, Stream and Raiffeisen entered into an amendment and restatement agreement pursuant to which Raiffeisen granted a deferral of the June 2014 principal payment due under the Facility Agreement until December 2016. In addition, Raiffeisen waived its rights under the Facility Agreement with respect to events of default resulting from (i) Stream Sub's non-payment of the June 2014 principal payment; and (ii) Stream Sub's breach of the financial covenants for the fiscal year ended November 30, 2013. Pursuant to the amendment and restatement agreement, (i) Stream Sub paid all fees, costs and expenses due and (ii) Stream Sub and Albpetrol Sh. A ("Albpetrol") entered into an agreement to postpone certain capital expenditures that were required under Stream's work program on its properties.

As of December 31, 2014, we had $10.5 million outstanding under the Term Loan Facility and no availability.

At December 31, 2014, we were not in compliance with certain conditions subsequent set forth in Section 4 of the Term Loan Facility, including the delivery to Raiffeisen of a copy of an agreement between Albpetrol and ourselves concerning postponement of capital expenditures. Raiffeisen has granted us a waiver on this requirement until May 5, 2015.

Prepayment Agreement

In April 2013, Stream and Stream Sub entered into the prepayment agreement (the "Prepayment Agreement") with Trafigura PTE Ltd ("Trafigura"). In October 2013, Stream received a $7.0 million prepayment under the Prepayment Agreement. No further prepayment requests can be made under the Prepayment Agreement. The prepayment is to be repaid by Stream's delivery of oil to Trafigura in accordance with an oil sales contract between Stream and Trafigura and bears interest at a rate equal to LIBOR plus 6% (6.17% at December 31, 2014). Stream must repay the prepayment at the times and in the quantities as set out in the oil sales contract, and all amounts must be repaid on or before August 31, 2015.

Each of Stream and Stream Sub is required to comply with certain financial and non-financial covenants under the Prepayment Agreement, including financial covenants that Stream must maintain, unless Trafigura agrees otherwise:

(i) EBITDA of not less than $10.0 million;

(ii) outstanding indebtedness of not more than twice its EBITDA; and

(iii) EBITDA of at least ten times greater than its accrued interest, commission, fees, discounts, prepayment fees, premiums, charges and other finance payments.

In addition, Stream must ensure that its coverage ratio is not less than 150% at all times. The coverage ratio is the ratio of the estimated aggregate valuation of the volume of crude oil to be delivered under the oil sales contract between Stream and Trafigura to the outstanding amount of the prepayment plus any applicable funding costs and fees.

Pursuant to the terms of the Prepayment Agreement, until amounts under the Prepayment Agreement are repaid, Stream Sub may not, in each case subject to certain exceptions, (i) create any liens over the Prepayment Agreement, or if such lien would have a material adverse effect, over any other assets or undertakings, (ii) enter into any amalgamation, demerger, merger, or corporate reconstruction, (iii) pay, repay or prepay any principal, interest or other amount on or in respect of or redeem, purchase or cancel any indebtedness owed actually or contingently to any shareholder of Stream Sub or an affiliate of any shareholder of Stream Sub, or (iv) reduce, return, purchase, repay, cancel or redeem any of its share capital.

Trafigura has termination and acceleration rights under the Prepayment Agreement upon the occurrence of certain events, including, among other events, failure to pay principal or interest when due, breach of certain covenants and obligations, cross default to other indebtedness, bankruptcy or insolvency, failure to meet the required financial covenant ratios and the occurrence of a material adverse effect. In addition, the occurrence of a change of control triggers termination and acceleration rights. A change of control is defined under the Prepayment Agreement as any person or group of persons acting in concert gaining ownership or control of Stream Sub. Control is defined as the power to direct or cause the direction of the management or policies of another person. Trafigura waived the change of control provision under the Prepayment Agreement in connection with our acquisition of Stream.

At December 31, 2014, Stream had $3.0 million outstanding under the Prepayment Agreement and no availability.

Viking International note

On September 16, 2014, Stream issued to Viking International Limited ("Viking International") a note in the principal amount of $6.8 million. The note was amended monthly to evidence additional advances. At December 31, 2014, we had $6.8 million outstanding under the Viking International note. At March 12, 2015, we had repaid the note.

Shareholder loan

In March 2014, Stream borrowed CAD $3.0 million from a shareholder of Stream. The loan bore interest at a fixed rate of 10.0% per annum, calculated and compounded monthly. At December 31, 2014, Stream had $2.6 million outstanding under the shareholder loan. On January 6, 2015, we repaid the shareholder loan in full with the net proceeds from our private placement of Notes.

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, 2014, 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. Loan financing costs, which are included in other assets, totaled approximately $2.7 million and $1.2 million as of December 31, 2014 and 2013, respectively. Amortization of loan financing costs totaled approximately $1.0 million, $0.5 million and $2.0 million during 2014, 2013 and 2012, respectively.

10. Shareholders' equity

November 2014 share issuance

In November 2014, we issued 3,218,641 common shares at a deemed price of $7.41 per common share for the acquisition of Stream (see Note 4).

July 2013 share issuance

In July 2013, we issued 351,074 common shares at a deemed price of $7.12 per common share to Direct Petroleum Inc. ("Direct") (see Note 15).

Restricted stock units

Under our 2009 Long-Term Incentive Plan (the "Incentive Plan"), we award 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 $1.4 million and $1.7 million with respect to awards of RSUs was recorded for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014, we had approximately $0.7 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 1.3 years. The following table sets forth RSU activity for the year ended December 31, 2014:

	Number of RSUs (in thousands)	Weighted Average Grant Date Fair Value Per RSU
Unvested RSUs outstanding at December 31, 2013	296	$ 8.91
Granted	179	8.57
Forfeited	(103)	8.17
Vested	(149)	10.06
Unvested RSUs outstanding at December 31, 2014	223	$ 8.21

Stock option plan

Our Amended and Restated Stock Option Plan (2006) (the “Option Plan”) terminated on June 16, 2009. All outstanding awards issued under the Option Plan remained in full force and effect. As of December 31, 2014 and 2013, there were no options outstanding under the Option Plan. All options previously outstanding under the Option Plan had a five-year term.

The fair value of stock options was determined using the Black-Scholes Model and was recognized over the service period of the stock option. All stock options are fully vested; therefore, no share-based compensation expense for stock option awards was recorded for the years ended December 31, 2014, 2013 and 2012. We did not grant any stock options during the years ended December 31, 2014, 2013 and 2012.

Details of stock option activity for the years ended December 31, 2014, 2013 and 2012 are presented below.

	2014 Number of Options (in thousands)	2014 Weighted Average Exercise Price Per share	2013 Number of Options (in thousands)	2013 Weighted Average Exercise Price Per share	2012 Number of Options (in thousands)	2012 Weighted Average Exercise Price Per share
Outstanding at beginning of year	–	$ –	16	$ 12.30	114	$ 9.07
Granted	–	–	–	–	–	–
Expired	–	–	(16)	12.30	(17)	10.00
Exercised	–	–	–	–	(81)	8.24
Outstanding at end of year	–	$ –	–	$ –	16	$ 12.30
Exercisable at end of year	–	$ –	–	$ –	16	$ 12.30

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, 2014, 2013 and 2012 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, 2014, 2013 and 2012 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 and warrants, whether exercisable or not. The computation of diluted earnings per common share excluded 758,586 and 959,438 antidilutive common share equivalents from the years ended December 31, 2013 and 2012, respectively.

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

(in thousands, except per share amounts)	2014	2013	2012
Net income (loss) from continuing operations	$29,096	$(13,271)	$(6,373)
Net (loss) income from discontinued operations	$(20)	$(442)	$22,619
Basic net income (loss) per common share:			
Shares:			
Weighted average common shares outstanding	37,829	37,069	36,742
Basic net income (loss) per common share:			
Continuing operations	$0.77	$(0.36)	$(0.17)
Discontinued operations	$–	$(0.01)	$0.62
Diluted net income (loss) per common share:			
Shares:			
Weighted average shares outstanding	37,829	37,069	36,742
Dilutive effect of:			
Restricted share units	152	–	–
Convertible notes	50	–	–

Weighted average common and common equivalent shares outstanding	38,031	37,069	36,742
Diluted net income (loss) per common share:			
Continuing operations	$0.77	$(0.36)	$(0.17)
Discontinued operations	$–	$(0.01)	$0.62

Additionally, we had a contingent liability at December 31, 2014 of approximately $4.2 million that is payable in our common shares (see Note 4). At the December 31, 2014 closing price of our common shares, this liability represented 0.6 million common shares that could be potentially dilutive to future earnings per share calculations.

Warrants

On December 31, 2014, we issued 233,334 warrants for the pledge of Gundem's Turkish resort (see Note 9). The common share purchase warrants have an exercise price of $5.99 per share and expire on June 30, 2016.

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 2014, 2013 and 2012 to income (loss) for the year as follows:

	2014	2013	2012
	(in thousands except rates)		
Statutory rate	0.00 %	0.00 %	0.00 %
Income (loss) from continuing operations before income taxes	$42,143	$(12,164)	$118
Increase (decrease) resulting from:		.	
Foreign tax rate differentials	8,897	(1,443)	8,607
Change in valuation allowance	228	982	(2,026)
Expiration of non-capital tax loss carryovers	1,841	1,367	1,601
Other	2,081	201	(1,691)
Total	$13,047	$1,107	$6,491

The components of the net deferred income tax liability at December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Deferred tax assets		
Unrealized derivative losses	$–	$1,594
Timing of accruals	692	1,043
Property and equipment	9,761	–
Non-capital loss carryovers	28,155	25,868
Valuation allowance	(37,153)	(28,404)
Total deferred tax assets	1,455	101
Deferred tax liabilities		
Unrealized derivative gain	(6,317)	–
Property and equipment	(50,196)	(13,093)

Total deferred tax liabilities	(56,513)	(13,093)
Net deferred tax liabilities	$(55,058)	$(12,992)
Components of net deferred tax liabilities		
Current assets	$329	$2,239
Non-current assets	1,181	903
Current liabilities	(2,138)	–
Non-current liabilities	(54,430)	(16,134)
Net deferred tax liabilities	$(55,058)	$(12,992)

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, 2014, we had non-capital tax losses in Turkey of approximately 151.5 million TRY (approximately $65.3 million), which will begin expiring in 2018; non-capital tax losses in Romania of approximately 7.8 million Romanian New Leu (approximately $2.1 million), which will begin expiring in 2015; non-capital losses in Bulgaria of approximately 8.3 million Bulgarian Lev (approximately $5.1 million), which will begin expiring in 2015; and non-capital tax losses in the United States of approximately $40.7 million, which will begin expiring in 2018.

Effective October 1, 2009, we continued to the jurisdiction of Bermuda. 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, Romania, Bulgaria, Morocco and Cyprus, with Turkey being the only jurisdiction with significant amounts of taxes due. Income tax returns filed in Turkey for years before 2009 are no longer subject to examination. The Turkish Ministry of Finance is currently conducting tax audits on two of our Turkish subsidiaries, Amity and TBNG, for the years ended December 31, 2010 and 2012, respectively. The Turkish Ministry of Finance recently began audits of our Turkish subsidiaries, TEMI and DMLP, for the year ended December 31, 2010.

In connection with our acquisition of Amity and Petrogas in August 2010, at December 31, 2012, we recognized a liability due to an uncertain tax position related to the transfer of Petrogas shares to Amity prior to the acquisition. Pursuant to the Amity share purchase agreement, we are indemnified from any tax liability arising in Turkey or Australia as a result of the transfer of the Petrogas shares for a period of up to six years from the sale date at an amount up to 50% of the purchase price of $96.3 million and, therefore, have recorded a corresponding receivable in other long-term assets.

As of December 31, 2014 the liability and receivable consisted of taxes of $3.0 million, penalties of $0.6 million and interest of $2.2 million. During the years ended December 31, 2014 and 2013, the Company recorded interest of $0.5 million and $0.5 million, respectively.

As of December 31, 2014, 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.

12. Segment information

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

	Corporate	Turkey	Bulgaria	Albania	Total	
	(in thousands)					
For the year ended December 31, 2014						
Total revenues	$–	$138,807	$23	$1,898	$140,728	
Production	–	18,059	134	1,806	19,999	
Transportation costs	–	–	–	284	284	
Exploration, abandonment, and impairment	–	19,820	44	–	19,864	
Cost of purchased gas	–	2,055	–	–	2,055	
Seismic and other exploration	178	4,106	1	–	4,285	
Revaluation of contingent consideration	–	–	(2,500)	–	(2,500)	
General and administrative	14,418	14,984	1,669	554	31,625	
Depreciation, depletion and amortization	124	48,452	18	333	48,927	
Accretion of asset retirement obligations	–	387	19	7	413	
Total costs and expenses	14,720	107,863	(615)	2,984	124,952	
Operating (loss) income	(14,720)	30,944	638	(1,086)	15,776	
Interest and other expense	(36)	(6,007)	(1)	(169)	(6,213)	
Interest income	350	770	4	–	1,124	
Gain on commodity derivative contracts	–	37,454	–	–	37,454	
Foreign exchange (loss) gain	(4)	(6,497)	(22)	525	(5,998)	
(Loss) income from continuing operations before income taxes	(14,410)	56,664	619	(730)	42,143	
Income tax provision	–	(13,659)	–	612	(13,047)	
Net (loss) income from continuing operations	$(14,410)	$43,005	$619	$(118)	$29,096	
Total assets at December 31, 2014	$51,919	$363,162	$4,675	$126,619	$546,375	(1)
Goodwill at December 31, 2014	$–	$6,935	$–	$–	$6,935	
Capital expenditures for the year ended December 31, 2014	$545	$109,563	$1,393	$2,271	$113,772	
For the year ended December 31, 2013						
Total revenues	$–	$130,701	$126	$–	$130,827	
Production	5	18,384	213	–	18,602	
Exploration, abandonment, and impairment	–	27,116	217	–	27,333	
Cost of purchased gas	–	2,247	–	–	2,247	
Seismic and other exploration	100	13,909	–	–	14,009	
Revaluation of contingent consideration	–	–	(5,000)	–	(5,000)	
General and administrative	12,685	16,068	267	–	29,020	
Depreciation, depletion and amortization	69	41,196	57	–	41,322	
Accretion of asset retirement obligations	–	475	33	–	508	
Total costs and expenses	12,859	119,395	(4,213)	–	128,041	
Operating (loss) income	(12,859)	11,306	4,339	–	2,786	
Interest and other expense	–	(3,929)	–	–	(3,929)	

Interest income	284	1,056	–	–	1,340
Loss on commodity derivative contracts	–	(2,698)	–	–	(2,698)
Foreign exchange (loss) gain	(9)	(9,664)	10	–	(9,663)
(Loss) income loss from continuing operations before income taxes	(12,584)	(3,929)	4,349	–	(12,164)
Income tax provision	–	(1,107)	–	–	(1,107)
Net (loss) income from continuing operations	$(12,584)	$(5,036)	$4,349	$–	$(13,271)
Total assets at December 31, 2013	$14,070	$321,749	$10,231	$–	$346,050 (1)
Goodwill at December 31, 2013	$–	$7,535	$–	$–	$7,535

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Capital expenditures for the year ended December 31, 2013	$1,003	$96,206	$2,742	$–	$99,951	
For the year ended December 31, 2012						
Total revenues	$–	$143,650	$258	$–	$143,908	
Production	169	17,328	307	–	17,804	
Exploration, abandonment, and impairment	285	39,708	–	–	39,993	
Cost of purchased gas	–	7,694	–	–	7,694	
Seismic and other exploration	304	4,726	10	–	5,040	
General and administrative	10,982	20,603	2,362	–	33,947	
Depreciation, depletion and amortization	30	28,092	93	–	28,215	
Accretion of asset retirement obligations	–	679	31	–	710	
Total costs and expenses	11,770	118,830	2,803	–	133,403	
Operating (loss) income	(11,770)	24,820	(2,545)	–	10,505	
Interest and other expense	(1,890)	(6,450)	–	–	(8,340)	
Interest income	308	2,110	–	–	2,418	
Loss on commodity derivative contracts	–	(5,548)	–	–	(5,548)	
Foreign exchange gain (loss)	79	1,054	(50)	–	1,083	
(Loss) income from continuing operations before income taxes	(13,273)	15,986	(2,595)	–	118	
Income tax provision	–	(6,491)	–	–	(6,491)	
Net (loss) income from continuing operations	$(13,273)	$9,495	$(2,595)	$–	$(6,373)	
Total assets at December 31, 2012	$14,930	$339,752	$1,957	$–	$356,639	(1)
Goodwill at December 31, 2012	$–	$9,021	$–	$–	$9,021	
Capital expenditures for the year ended December 31, 2012	$–	$80,957	$867	$–	$81,824	

(1) Excludes assets from our discontinued Moroccan operations of $28,000, $0.5 million, and $1.6 million at December 31, 2014, 2013 and 2012, respectively.

13. Financial instruments

Interest rate risk

We are exposed to interest rate risk as a result of our variable rate short-term cash holdings and borrowings under the Senior Credit Facility.

Foreign currency risk

We have underlying foreign currency exchange rate exposure. Our currency exposures relate to transactions denominated in the Bulgarian Lev, European Union Euro, Albanian Lek, 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, 2014, we had 12.5 million TRY (approximately $5.4 million) 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. At December 31, 2014 and 2013, we were a party to commodity derivative contracts.

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. 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, the TBNG credit facility, the Term Loan Facility, the Prepayment Agreement, the Viking International note, and the shareholder loan were each estimated to have a fair value approximating the carrying amount at December 31, 2014 and 2013 due to the short maturity of those instruments. Indebtedness under the Senior Credit Facility was estimated to have a fair value approximating the carrying amount at December 31, 2014 and 2013 since the interest rate is generally market sensitive.

The financial assets and liabilities measured on a recurring basis at December 31, 2014 and 2013 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 call options purchased to hedge our oil production.

We utilize independent third-party pricing services to determine the fair values of derivative contracts. The independent third party determines fair values using 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. Generally, we obtain a single price or quote per instrument from independent third parties to assist in establishing the fair value of these contracts. We review prices received from service providers for unusual fluctuations to ensure that the prices represent a reasonable estimate of fair value.

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2014:

	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)			
Assets:				
Commodity derivative contracts	$–	$ 31,587	$ –	$31,587

Liabilities:				
Convertible notes	-	(47,400)	-	(47,400)
Total	$–	$ (15,813)	$ –	$(15,813)

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2013:

	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:				
Commodity derivative contracts	$–	$ (7,967)	$ –	$(7,967)
Total	$–	$ (7,967)	$ –	$(7,967)

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14. Commitments

Our aggregate annual commitments, other than our loans payable, as of December 31, 2014 were as follows:

	Payments Due By Year						
	Total	2015	2016	2017	2018	2019	Thereafter
	(in thousands)						
Interest	$26,288	$11,077	$9,598	$4,977	$595	$ 41	$ -
Leases	7,097	2,826	346	195	33	-	3,697
Total	$33,385	$13,903	$9,944	$5,172	$628	$ 41	$ 3,697

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, Albania and Turkey. We also lease apartments in Turkey and Dallas, as well as operations yards in Turkey. Rent expense for the years ended December 31, 2014, 2013 and 2012 was $2.2 million, $3.3 million and $3.5 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.

Aglen

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 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.

Direct Petroleum

In July 2013, we entered into a second amendment (the "Amendment") to the purchase agreement (the "Purchase Agreement") with Direct. The Amendment set forth a new obligation to drill and test the Deventci-R2 well by May 1, 2014. We completed the drilling and testing requirements pursuant to the Amendment during April 2014, which resulted in the reversal of a $2.5 million contingent liability recorded in 2011. The reversal is recognized in our consolidated statements of comprehensive income (loss) under the caption "Revaluation of contingent consideration" for the year ended December 31, 2014.

In addition, the Amendment provides that we will issue $7.5 million in common shares if the Deventci-R2 well is a commercial success (as defined in the Purchase Agreement) on or prior to May 1, 2016. We will record any provision for this contingent consideration when it is estimable and probable. As of December 31, 2014, we had not recorded a contingent liability for this contingent consideration.

Additionally, the Amendment provides that if the Bulgarian government issues a production concession over the Stefenetz concession area (the “Stefenetz Concession Area”), Direct will be entitled to a payment of $10.0 million in common shares, or a pro rata amount if the production concession is less than 200,000 acres. We do not have enough information to estimate the potential contingent liability we would incur in the event the Bulgarian government issues a production concession over the Stefenetz Concession Area. Any provision for this contingent consideration will be recorded when it becomes probable and estimable.

16. Related party transactions

Equity transactions

On September 1, 2010, we issued 730,000 common share purchase warrants to Dalea Partners, LP (“Dalea”) pursuant to a credit agreement with Dalea. The common share purchase warrants had an exercise price of $60.00 per share, and expired on September 1, 2013. Dalea is an affiliate of Mr. Mitchell.

On December 31, 2014, the Company issued 134,169 common share purchase warrants to Mr. Mitchell and 23,333 common share purchase warrants to each of Mr. Mitchell’s children (collectively, the “Warrants”) pursuant to warrant agreements. These Warrants were issued to Mr. Mitchell and his children as shareholders of the entity Gundem, which agreed to pledge its primary asset, a Turkish resort, in exchange for an extension of the maturity date of a credit agreement between the Company and a Turkish bank. As consideration for the pledge of the Gundem resort, the independent members of the Company’s board of directors approved the issuance of the Warrants to be allocated in accordance with each shareholder’s ownership percentage of Gundem. Pursuant to the warrant agreements, the Warrants are immediately exercisable, expire 18 months from the date of the release of the pledge on the Gundem resort, and entitle the holder to purchase one Common Share for each Warrant at an exercise price of $5.99 per share.

Sale of oilfield services business

On June 13, 2012, we closed the sale of our oilfield services business, which was substantially comprised of our wholly owned subsidiaries Viking International and Viking Geophysical Services, Ltd. (“Viking Geophysical”), to a joint venture owned by Dalea and funds advised by Abraaj Investment Management Limited for an aggregate purchase price of $168.5 million, consisting of approximately $157.0 million in cash and a $11.5 million promissory note from Dalea. The promissory note is payable five years from the date of issuance or earlier upon the occurrence of certain specified events, including an initial public offering by the joint venture. Upon the consummation of an initial public offering by the joint venture and the prior approval of Dalea, we can elect to convert the outstanding balance of the promissory note, including accrued interest, into the number of shares offered in the initial public offering equal to such outstanding balance divided by the per share purchase price paid by the public in the initial public offering. The promissory note bears interest at a rate of 3.0% per annum and is guaranteed by Mr. Mitchell.

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 85% 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.

Effective January 1, 2011, our wholly owned subsidiary, TEMI, entered into an accommodation agreement under which it leased rooms, flats and office space at a facility owned by Gundem. Under the accommodation agreement, TEMI leases six rooms and pays the TRY equivalent of $6,000 per month.

On August 23, 2011, the Company's wholly owned subsidiary, TransAtlantic Petroleum (USA) Corp. ("TransAtlantic USA"), entered into an office lease with Longfellow to lease approximately 5,300 square feet of corporate office space in Addison, Texas. The initial lease term under the lease commenced on July 1, 2013, the date that TransAtlantic USA subleased a portion of its previous office space in Dallas, Texas (the "Commencement Date"). The lease expires five years after the Commencement Date, unless earlier terminated in accordance with the lease. During the initial lease term, TransAtlantic USA will pay monthly rent of $6,625 to Longfellow plus, utilities, real property taxes and liability insurance. Prior to the Commencement Date, no rent, utilities, real property taxes and/or liability insurance were required to be paid to Longfellow under the lease.

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. 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 June 13, 2012, we entered into a transition services agreement with Viking Services Management, Ltd. ("Viking Management") 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 transition services agreement, we agreed to provide certain administrative services, including, but not limited to, continued use of certain of our employees and independent contractors, a guarantee of a lease for flats in Turkey, Turkish tax or legal advice and services, office space in Istanbul, Turkey, information technology support and certain software or licenses to Viking Management. In addition, Viking Management agreed to cause its subsidiaries to provide us with the continued use of certain office space in Tekirdag, Turkey. The transition services agreement terminated on June 13, 2014. In the third quarter of 2012, we entered into an addendum to the transition services agreement whereby Viking Management agreed to cause its subsidiaries to provide us with the continued use of certain equipment yards in the Thrace Basin and in southwestern Turkey. The addendum terminated on April 1, 2014.

On April 5, 2013 (the "First Floor Commencement Date"), TransAtlantic USA entered into an office lease with Longfellow to lease approximately 4,700 square feet of additional corporate office space in Addison, Texas. The initial lease term commenced on the First Floor Commencement Date and expires five years after the First Floor Commencement Date, unless earlier terminated in accordance with the lease. For the first year of the lease, TransAtlantic USA will pay monthly rent of $7,533 to Longfellow plus utilities, real property taxes and liability insurance.

On March 26, 2014, our wholly owned subsidiaries, TEMI and TBNG, entered into an equipment yard services agreement effective as of April 1, 2014 with Viking International for services related to the use of oilfield equipment yards located in Diyarbaki, Tekirdag and Muratli, Turkey. The initial term of the agreement is for twelve months, and the term of the agreement renews automatically for additional twelve-month periods unless earlier terminated. During the initial term, TEMI will pay monthly services fees of $17,250 to Viking International for services related to the use of Diyarbakir equipment yard, and TBNG will pay monthly service fees of $17,250 to Viking International for services related to the use of Tekirdag and Muratli equipment yards.

For the years ended December 31, 2014 and 2013, we incurred capital and operating expenditures of $96.4 million and $85.7 million, respectively, related to our various related party agreements.

Debt transactions

As of December 31, 2014 we sold $47.4 million of Notes in a non-brokered private placement. Dalea purchased $2.0 million of the Notes; trusts benefitting Mr. Mitchell's four children each purchased $2.0 million of the Notes; Pinon Foundation, a non-profit charitable organization directed by Mr. Mitchell's spouse, purchased $10.0 million of the Notes; the three children of Brian Bailey, a director of the Company, each purchased $100,000 of the Notes; Wil Saqueton, the Company's vice president and chief financial officer, purchased $100,000 of the Notes; Matthew McCann, the Company's general counsel and corporate secretary, purchased $200,000 of the Notes; and a trust benefitting Barbara and Terry Pope, Mr. Mitchell's sister-in-law and brother-in-law, purchased $200,000 of the Notes.

On September 16, 2014, Stream issued to Viking International a note in the principal amount of $6.8 million. At December 31, 2014, we had $6.8 million outstanding under the Viking International note. At March 12, 2015, we had repaid the note (see Note 9).

Other related party transactions

During the year we incurred $60,000 of geology consulting services from Roxanna Oil Company, a private oil and natural gas exploration and production company ("Roxanna"). One of our directors is the chairman of the board of Roxanna.

The following table summarizes related party accounts receivable and accounts payable as of December 31, 2014 and December 31, 2013:

	2014	2013
	(in thousands)	
Related party accounts receivable:		
Viking International master services agreement	$355	$939
Riata Management Service Agreement	159	65
Dalea promissory note	88	–
Total related party accounts receivable	$602	$1,004
Related party accounts payable:		
Viking International master services agreement	$16,754	$15,956
Riata Management Service Agreement	1,734	334
Viking Geophysical master services agreement	–	6,800
Total related party accounts payable	$18,488	$23,090

17. Discontinued operations

Discontinued operations in Morocco

On June 27, 2011, we decided to discontinue our operations in Morocco. We have substantially completed the process of winding down our operations in Morocco. We have presented the Moroccan segment operating results as discontinued operations for all periods presented.

Discontinued operations of oilfield services business

On June 13, 2012, we closed the sale of our oilfield services business, which was substantially comprised of our wholly owned subsidiaries Viking International and Viking Geophysical, to a joint venture owned by Dalea and funds advised by Abraaj Investment Management Limited for an aggregate purchase price of $168.5 million, consisting of approximately $157.0 million in cash and a $11.5 million promissory note from Dalea. The transaction was approved by a special committee of our board of directors after the receipt of a fairness opinion solely for the benefit of the special committee, which was subject to certain assumptions and limitations as provided in such opinion. The promissory note is payable five years from the date of issuance or earlier upon the occurrence of certain specified events, including an initial public offering by the joint venture. Upon the consummation of an initial public offering by the joint venture and the prior approval of Dalea, we can elect to convert the outstanding balance of the promissory note, including accrued interest, into the number of shares offered in the initial public offering equal to such outstanding balance divided by the per share purchase price paid by the public in the initial public offering. The promissory note bears interest at a rate of 3.0% per annum and is guaranteed by Mr. Mitchell. We used a portion of the net proceeds from the sale to pay off our $73.0 million credit agreement with Dalea, our $11.0 million credit facility with Dalea, our $0.9 million promissory note with Viking Drilling and our $1.8 million credit agreement with a Turkish bank. In addition, we used a portion of the net proceeds from the sale of our oilfield services business to pay down approximately $45.2 million in outstanding indebtedness under our Amended and Restated Credit Facility. We have presented the oilfield services segment operating results as discontinued operations for the years ended December 31, 2014 and 2013.

The assets and liabilities held for sale at December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Cash	$16	$23
Other assets	12	513
Total assets held for sale	$28	$536
Accrued expenses and other liabilities	$6,928	$7,559
Total liabilities held for sale	$6,928	$7,559

Our operating results from discontinued operations for the years ended December 31, 2014, 2013 and 2012 are summarized as follows:

	2014	2013	2012
	(in thousands)		
Total revenues	$–	$–	$19,956
Total costs and expenses	(20)	(505)	(24,682)
Total other income (expense)	–	63	(357)
Loss from discontinued operations before income taxes	(20)	(442)	(5,083)
Gain on disposal of discontinued operations	–	–	35,999
Income tax provision	–	–	(8,297)
Net (loss) income from discontinued operations	$(20)	$(442)	$22,619

18. Subsequent events

Convertible Notes

Subsequent to December 31, 2014, we sold an additional $7.6 million of Notes in a non-brokered private placement, bringing the total sale of the Notes to $55.0 million. We completed the private placement on February 20, 2015.

Exchange Notes

On February 20, 2015, we issued $55.0 million of Exchange Notes in exchange for all outstanding Notes. The Exchange 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 Exchange Notes bear interest at an annual rate of 13.0%, payable semi-annually, in arrears, on January 1 and July 1 of each year, commencing on July 1, 2015. The Exchange Notes will mature on July 1, 2017, unless earlier redeemed or converted.

Holders may, at any time after July 1, 2015 and from time to time at such holder's option, convert, subject to certain terms and conditions, any or all of the principal of any Exchange Note into fully paid and nonassessable Common Shares at the conversion price. The initial conversion price is $6.80 per Common Share, subject to adjustment as described in the Indenture. Prior to or contemporaneously with the conversion of any of the principal of an Exchange Note, all accrued but unpaid interest on the principal amount being converted will be paid in cash. The Exchange Notes may not be converted into Common Shares on the maturity date or the redemption date.

At any time on or after July 1, 2015, we may redeem all or a part of the Exchange Notes at the redemption prices specified below (expressed in percentages of principal amount on the redemption date), plus accrued and unpaid interest to the redemption date.

Period Beginning	Redemption Price
July 1, 2015	107.5%
January 1, 2016	105.0%
July 1, 2016	102.5%
January 1, 2017	100.0%

If we experience a fundamental change (as defined in the Indenture), we will be required to make an offer to repurchase the Exchange Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to but excluding the date of repurchase. Additionally, if we sell certain assets in exchange for $50.0 million or more in cash consideration, in certain circumstances, we will be required to use a portion of the net cash proceeds of such sale to make an offer to repurchase Exchange Notes at a price equal to the price we would be required to pay for an optional redemption at such time, plus accrued and unpaid interest, if any, up to but excluding the date of repurchase. The Indenture provides for customary events of default. The Indenture contains limited covenants, including a covenant that will limit our ability to incur liens securing funded debt.

TRANSATLANTIC PETROLEUM LTD.

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, 2014 and 2013.

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31,
	(in thousands, except per share data)			
For the year ended December 31, 2014:				
Revenues	$33,646	$41,061	$36,077	$29,944
Net income	3,973	1,437	8,313	15,353
Comprehensive income (loss)	678	6,529	(4,343)	11,887
Basic and diluted net income (loss) per common shares from continuing operations	$0.11	$0.04	$0.22	$0.39
For the year ended December 31, 2013:				
Revenues	$34,044	$30,516	$32,345	$33,922
Net income (loss)	2,939	2,903	(4,973)	(14,582)
Comprehensive income (loss)	103	(10,640)	(15,599)	(24,550)
Basic and diluted net income (loss) per common shares from continuing operations	$0.08	$0.08	$(0.13)	$(0.39)

(1) The sum of the individual quarterly net income (loss) amounts per share may not agree with year-to-date net income (loss) 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 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 the Company's expected future cash flows to be obtained from the development and production of its oil and natural gas properties or of the value of its 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 and Deloitte LLP to prepare our reserves estimates in Turkey and Albania, respectively. These estimates comprise 100% of our estimated proved reserves (by volume) at December 31, 2014.

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 Albania, 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 un-weighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 2014, 2013 and 2012. 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		
2014	$94.53	$8.71
2013	$102.07	$9.92
2012	$108.66	$8.74
Albania		
2014	$69.55	$10.00

The following table sets forth our estimated net proved reserves (natural gas converted to Mboe by dividing Mmcf by six), including changes therein, and proved developed reserves:

Disclosure of reserves quantities

	Oil (Mbbl)	Natural Gas (Mmcf)	Total (Mboe)
Total proved reserves			
December 31, 2011	11,215	13,223	13,419
Extensions and discoveries	1,794	3,055	2,303
Revisions of previous estimates	(2,540)	423	(2,470)
Sales volumes	(949)	(4,238)	(1,655)
December 31, 2012	9,520	12,463	11,597
Extensions and discoveries	1,563	2,652	2,005
Revisions of previous estimates	(436)	3,436	137
Sales volumes	(933)	(3,512)	(1,518)
December 31, 2013	9,714	15,039	12,221
Acquisitions	14,296	8,249	15,671
Extensions and discoveries	4,740	2,809	5,208
Revisions of previous estimates	1,254	1,668	1,532
Sales volumes	(1,339)	(3,262)	(1,883)
December 31, 2014	28,665	24,503	32,749
Proved developed reserves			
December 31, 2012:			
Proved developed producing	4,241	5,228	5,112
Proved developed non-producing	910	2,887	1,391
Total	5,151	8,115	6,503
December 31, 2013:			
Proved developed producing	4,540	7,189	5,738
Proved developed non-producing	335	3,261	879
Total	4,875	10,450	6,617
December 31, 2014:			
Proved developed producing	10,783	5,572	11,712
Proved developed non-producing	9,974	3,979	10,637
Total	20,757	9,551	22,349
Proved undeveloped reserves			
As of December 31, 2012	4,369	4,348	5,094
As of December 31, 2013	4,839	4,589	5,604
As of December 31, 2014	7,908	14,952	10,400

For the year ended December 31, 2014, we had a proved reserve increase of 20,528 Mboe, or 168.0%, compared to 2013. This increase was primarily attributable to the acquisition of Stream, the continued success of our horizontal drilling campaigns in the Selmo oil field and the Thrace Basin and the successful appraisal of the Bahar oil field. The Albanian assets of Stream constituted 15,634 Mboe or 76.2% of the increase. Of the proved reserves, 88.9% are in the proved developed category and are part of the producing oil assets in Albania. The increase in proved reserves was partially offset by sales volumes of 1,883 Mboe in 2014, consisting of 1,339 Mbbls of oil and 3,262 Mmcf of natural gas.

At December 31, 2014, we recorded an increase in proved reserves of 5,208 Mboe through extensions and discoveries. These increases were due to the following factors: (i) horizontal drilling in Selmo, which resulted in the conversion of 2,234 Mboe from probable or possible reserves to proved reserves due to successful wells in the previously under-drilled southeast portion of the field and confirming that oil still remains at, or below, the current oil-water contact; (ii) the addition of 467 Mboe in the Thrace Basin as a result of the Gurgen discovery and successful Sogucak test in the Kuzey Emirali-1 well; (iii) the addition of 2,243 Mboe due to successful appraisal wells on the Bahar structure and (iv) the addition of 264 Mbbls in the Arpatepe oil field as a result of the Arpatepe-7 appraisal well success which extended the field to the southeast.

At December 31, 2014, we recorded an increase in reserves due to technical revisions of 1,254 Mbbl and 1,668 Mmcf (1,532 Mboe total). The revision in oil of 1,254 Mbbls was an increase from December 31, 2013, in which we recorded a loss of 436 Mbbls, and was mostly attributable to well performance in Selmo. Prior to initiating the horizontal well campaign in Selmo in 2013, drilling had been halted due to poor vertical well performance. This resulted in negative revisions to estimates for 2013. By contrast, the horizontal wells drilled in late 2013 and throughout 2014 have performed better than original estimates and thus resulted in positive technical revisions. The revision in gas of 1,668 Mmcf was a decrease from December 31, 2013, in which we recorded 3,436 Mmcf in technical revisions and was mostly attributable to a decrease in activity in the Thrace Basin, where we did not introduce any new technology to the gas fields. In 2013, we successfully fracture stimulated the Mezardere formation for the first time. This led to an aggressive recompletion program as we fine-tuned our stimulation methodology which, in turn, greatly increased many behind pipe reserves. The performance of these fracture stimulated wells versus the unstimulated type curves allowed for positive reserve revisions.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows relating to estimated proved reserves as of December 31, 2014, 2013 and 2012 are shown in the table below. In our calculation of standardized measure we have utilized statutory tax rates of 20% and 50% for Turkey and Albania, respectively.

	Turkey	Albania	Total
	(in thousands)		
As of and for the year ended December 31, 2014			
Future cash inflows	$1,504,369	$921,237	$2,425,606
Future production costs	(309,528)	(239,149)	(548,677)
Future development costs	(234,675)	(123,085)	(357,760)
Future income tax expense	(148,437)	(243,774)	(392,211)
Future net cash flows	811,729	315,229	1,126,958
10% annual discount for estimated timing of cash flows	(272,649)	(182,227)	(454,876)
Standardized measure of discounted future net cash flows related to proved reserves	$539,080	$133,002	$672,082
As of and for the year ended December 31, 2013			
Future cash inflows	$1,141,775	$-	$1,141,775
Future production costs	(190,337)	-	(190,337)
Future development costs	(131,643)	-	(131,643)
Future income tax expense	(127,971)	-	(127,971)

Future net cash flows	691,824	-	691,824
10% annual discount for estimated timing of cash flows	(196,055)	-	(196,055)
Standardized measure of discounted future net cash flows related to proved reserves	$495,769	$-	$495,769
As of and for the year ended December 31, 2012			
Future cash inflows	$1,143,346	$-	$1,143,346
Future production costs	(227,876)	-	(227,876)
Future development costs	(93,267)	-	(93,267)
Future income tax expense	(122,582)	-	(122,582)
Future net cash flows	699,621	-	699,621
10% annual discount for estimated timing of cash flows	(221,712)	-	(221,712)
Standardized measure of discounted future net cash flows related to proved reserves	$477,909	$-	$477,909

Changes in the standardized measure of discounted future net cash flows

The following are the principal sources of changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2014, 2013 and 2012.

	2014	2013	2012
	(in thousands)		
Standardized measure, January 1,	$495,769	$477,909	$531,797
Net change in sales and transfer prices and in production (lifting) costs related to future production	(75,912)	(7,868)	(594)
Changes in future estimated development costs	(151,238)	(73,753)	(66,178)
Sales and transfers of oil and natural gas during the period	(118,083)	(108,674)	(116,477)
Net change due to extensions and discoveries	245,643	112,814	124,643
Net change due to purchases of minerals in place	235,855	-	-
Net change due to revisions in quantity estimates	72,222	7,678	(133,637)
Previously estimated development costs incurred during the period	63,250	47,252	50,810
Accretion of discount	44,439	56,376	64,584
Other	(19,340)	(12,070)	(10,644)
Net change in income taxes	(120,523)	(3,895)	33,605
Standardized measure, December 31,	$672,082	$495,769	$477,909

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, 2014, 2013 and 2012 are summarized as follows:

	Turkey	Albania	Bulgaria	Total
	(in thousands)			
For the year ended December 31, 2014				
Acquisitions of properties				
Proved	$-	$99,927	$ -	$99,927
Unproved	-	16,140	-	16,140
Exploration	39,143	2,161	1,291	42,595
Development	63,250	110	44	63,404
Total costs incurred	$102,393	$118,338	$ 1,335	$222,066
For the year ended December 31, 2013				
Acquisitions of properties				
Proved	$-	$-	$ -	$-
Unproved	6,750	-	-	6,750
Exploration	40,258	-	2,742	43,000
Development	47,252	-	-	47,252
Total costs incurred	$94,260	$-	$ 2,742	$97,002
For the year ended December 31, 2011				
Acquisitions of properties				
Proved	$-	$-	$ -	$-
Unproved	-	-	-	-

Exploration	36,465	-	-	36,465
Development	43,824	-	867	44,691
Total costs incurred	$80,289	$-	$ 867	$81,156

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EXHIBIT INDEX

2.1 Stock Purchase Agreement, dated March 15, 2012, by and among TransAtlantic Petroleum Ltd., TransAtlantic Worldwide, Ltd., Longe Energy Limited, TransAtlantic Petroleum (USA) Corp., TransAtlantic Petroleum Cyprus Limited, Viking International Limited, Viking Geophysical Services, Ltd., Viking Oilfield Services SRL and Dalea Partners, LP. (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 10, 2012).

2.2 Arrangement Agreement, dated as of September 2, 2014, between TransAtlantic Petroleum Ltd. and Stream Oil & Gas Ltd. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated September 2, 2014, filed with the SEC on September 8, 2014).

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).

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 Registration Rights Agreement, dated February 18, 2011, by and between TransAtlantic Petroleum Ltd. and Direct Petroleum Exploration, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated February 18, 2011, filed with the SEC on February 24, 2011).

4.3 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).

4.4 Indenture, dated as of February 20, 2015, between TransAtlantic Petroleum Ltd. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated February 20, 2015, filed with the SEC on February 25, 2015).

4.5 Form of 13.0% Convertible Note due 2017 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K dated February 20, 2015, filed with the SEC on February 25, 2015).

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† Executive Employment Agreement, effective January 1, 2008, by and between TransAtlantic Petroleum Corp. and Jeffrey S. Mecom (incorporated by reference to Exhibit 4.8 to the Company's Annual Report on Form 20-F (File No. 000-31643), filed with the SEC on May 14, 2008).

10.5† 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).

10.6† 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).

10.7 Amended and Restated Credit Agreement, dated as of May 18, 2011, by and between DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd., TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors, the lenders party thereto from time to time, and Standard Bank Plc and BNP Paribas (Suisse) SA, as joint mandated lead arrangers and joint bookrunners, and Standard Bank Plc as letter of credit issuer, administrative agent, collateral agent and technical agent (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated May 17, 2011, filed with the SEC on May 19, 2011).

10.8 Amendment No. 1 to the Amended and Restated Credit Agreement, dated as of August 4, 2011, by and between Amity Oil International Pty. Ltd., DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd. and TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors, and Standard Bank Plc as administrative agent and as collateral agent (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 9, 2011).

10.9 Amendment No. 2 to the Amended and Restated Credit Agreement, dated as of September 14, 2011, by and between Amity Oil International Pty. Ltd., DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd. and TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors and Standard Bank Plc as administrative agent and collateral agent (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 9, 2011).

10.10 Office Lease, dated August 23, 2011, 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 23, 2011, filed with the SEC on August 25, 2011).

10.11† 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).

10.12 Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking International Limited (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).

10.13 Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).

10.14 Master Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Geophysical Services, Ltd. (incorporated by reference to Exhibit 10.3 to the Company's Current Report on

Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).

10.15 Transition Services Agreement, dated June 13, 2012, by and between TransAtlantic Petroleum, Ltd. and Viking Services Management, Ltd. (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).

10.16 Convertible Promissory Note made by Dalea Partners, LP to the order of TransAtlantic Petroleum Ltd., dated June 13, 2012 in the principal sum of $11,500,000 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, dated June 13, 2012, filed with the SEC on June 19, 2012).

10.17 Amendment No. 3 to the Amended and Restated Credit Agreement, dated as of November 21, 2012, by and between Amity Oil International Pty. Ltd., DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri Insaat Sanayive Ticaret A.S., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd. and TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors and Standard Bank Plc as administrative agent and collateral

agent (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K, filed with the SEC on May 16, 2013).

10.18 Office Lease, dated April 5, 2013, 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 May 8, 2013, filed with the SEC on May 14, 2013).

10.19 Equipment Yard Services Agreement, by and between TransAtlantic Exploration Mediterranean International Pty Ltd, Thrace Basin Natural Gas (Turkiye) Corporation and Viking International Limited, dated as of April 1, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated March 26, 2014, filed with the SEC on March 28, 2014).

10.20 Credit Agreement, dated as of May 6, 2014, by and between Amity Oil International Pty Ltd, DMLP, Ltd., Petrogas Petrol Gaz ve Petrokimya Ürünleri Inşaat Sanayi ve Ticaret A.Ş., Talon Exploration, Ltd., TransAtlantic Exploration Mediterranean International Pty. Ltd., TransAtlantic Turkey, Ltd., as borrowers, TransAtlantic Petroleum Ltd., TransAtlantic Petroleum (USA) Corp., TransAtlantic Worldwide, Ltd., as guarantors, the lenders party thereto from time to time, and BNP Paribas (Suisse) SA as coordinating mandated lead arranger, sole bookrunner, letter of credit issuer, administrative agent, collateral agent and technical agent and International Finance Corporation, as mandated lead arranger (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 8, 2014).

10.21† Summary of annual restricted stock award arrangement with Mr. Wil F. Saqueton (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on November 6, 2014).

10.22* Facility Agreement, dated December 15, 2011, by and among Stream Oil & Gas Ltd., Stream Oil & Gas Ltd. (BC), and Raiffeisen Bank Sh.A.

10.23* Amended and Restated Facility Agreement, dated September 17, 2014, by and among Stream Oil & Gas Ltd., Stream Oil & Gas Ltd. (BC), and Raiffeisen Bank Sh.A.

10.24* Amendment and Restatement Agreement, dated September 17, 2014, by and among Stream Oil & Gas Ltd., Stream Oil & Gas Ltd. (BC), and Raiffeisen Bank Sh.A.

10.25* Prepayment Agreement, dated April 18, 2013, by and between Stream Oil & Gas Ltd. and Trafigura PTE Ltd.

10.26* Coordination Agreement, dated May 22, 2013, by and among Raiffeisen Bank Sh.A, Trafigura PTE Ltd., Stream Oil & Gas Ltd. and Stream Oil & Gas Ltd. (BC).

10.27* Promissory Note made by Stream Oil & Gas Ltd. to the order of Viking International Ltd., dated September 12, 2014 in the principal sum of $6,800,000.

21.1*	Subsidiaries of the Company.
23.1*	Consent of KPMG LLP.
23.2*	Consent of DeGolyer and MacNaughton.
23.3*	Consent of Deloitte LLP.
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 Chief 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 Chief Financial Officer of the Company, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of DeGolyer and MacNaughton, dated March 6, 2015.
99.2*	Report of Deloitte LLP, dated February 27, 2015.
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.

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