TRANSATLANTIC PETROLEUM LTD.

FORM 10-K
(Annual Report)

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Address	16803 DALLAS PARKWAY ADDISON, TX 75001
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Industry	Oil & Gas Operations
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2012

OR

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

For the transition period from __________ to __________

Commission file number 001-34574

TRANSATLANTIC PETROLEUM LTD.
(Exact name of registrant as specified in its charter)

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

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

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

Title of each class	Name of each exchange on which registered
Common shares, par value $0.01	**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 ☒

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

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

Indicate by check mark whether the registrant has submitted electronically 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 ☒ 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 ☒
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 ☒

The aggregate market value of common shares, par value $0.01 per share, held by non-affiliates of the registrant, based on the last sale price of the common shares on June 29, 2012 (the last business day of the registrant's most recently completed second fiscal quarter), was approximately $229.0 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 May 10, 2013, there were 368,906,996 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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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, collectibility 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.

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.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent. Boe is not included in the DeGolyer and MacNaughton reserve 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 drilling 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.

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

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.

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.

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.

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.

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.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

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, 2012, 2011 and 2010 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.

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, have stable governments, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2012, we held interests in approximately 4.4 million net onshore acres and 30,000 net offshore acres of developed and undeveloped oil and natural gas properties in Turkey, Bulgaria and Romania. As of May 1, 2013, approximately 40% 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 reserve report prepared by DeGolyer and MacNaughton, independent petroleum engineers, our estimated proved reserves at December 31, 2012 were approximately 11.6 net Mmboe, of which 82% was oil. Of these estimated proved reserves, 56% were proved developed reserves. As of December 31, 2012, the PV-10 and Standardized Measure of our proved reserves were $511.1 million and $435.9 million, respectively. See "Item 2. Properties—Value of Proved Reserves" for a reconciliation of PV-10 to the Standardized Measure.

Recent Developments

Amendment to Ban on Fracture Stimulation in Bulgaria. In January 2012, the Bulgarian Parliament enacted legislation that banned fracture stimulation 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. In November 2012, we were awarded a production concession over the Koynare concession area, which covers approximately 163,000 acres. As a result, we expect our conventional natural gas exploration, development and production activity in Bulgaria to resume in 2013. As long as the current legislation remains in effect, our unconventional natural gas exploration, development and production activities in Bulgaria will be significantly constrained.

Closing of 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 Limited ("Viking International") and Viking Geophysical Services, Ltd. ("Viking Geophysical"), to a joint venture owned by Dalea Partners, LP ("Dalea"), an affiliate of Mr. Mitchell, 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, LLC ("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 to pay down approximately $45.2 million in outstanding indebtedness under our amended and restated senior secured credit facility, as amended (the "Amended and Restated Credit Facility"), with Standard Bank Plc ("Standard Bank") and BNP Paribas Suisse SA ("BNP Paribas").

Entry into Transition Services Agreement. On June 13, 2012, we also entered into a transition services agreement with Viking Services Management, Ltd. ("Viking Management") in connection with the sale of our oilfield services business. 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 and 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. 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 transition services agreement has a two-year term. Viking Management agreed to use commercially reasonable efforts to eliminate its need for such services as soon as practicable following the entry into the agreement.

Entry into Master Services Agreements. On June 13, 2012, we also entered into separate master services agreements with each of Viking International, Viking Petrol Sahasi Hizmetleri A.S. ("VOS") and Viking Geophysical in connection with the sale of our oilfield services business. 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.

Amendment to Amended and Restated Credit Facility . In November 2012, we entered into an amendment to our Amended and Restated Credit Facility. The amendment, among other things, reduced the commitment fee rates, extended the first commitment reduction date from September 30, 2012 to December 31, 2013 and provided for a scheduled quarterly reduction of the commitment amount beginning on December 31, 2013. On December 31, 2013, the commitment amount, which is currently $78.0 million, will be reduced to $67.5 million and will decrease at the end of each fiscal quarter until reaching zero on March 31, 2016.

Our Strengths

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

Significant Exploration Acreage. As of May 15, 2013, we held approximately 3.9 million net onshore acres and 30,000 net offshore acres in Turkey and Bulgaria. The majority of this onshore acreage is exploratory, and we will seek to develop a portion of this acreage through joint ventures or farm-out agreements with major industry players.

Strong and Experienced Management Team. Our management team, led by our chief executive officer, Mr. Mitchell, includes executives and managers with significant industry, operational and technical experience. Mr. Mitchell previously built Riata Energy, Inc. (now 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. Upon his departure, Riata Energy, Inc. had 1 Tcf in proved reserves, 300 miles of natural gas-gathering pipeline, more than 34,000 horsepower of natural gas compression, and owned or operated 43 drilling rigs. On average, our operations management team has more than 20 years of industry experience and is integral in executing our growth strategy.

Growing Production and Cash Flow. We expect continued production and cash flow growth through the development of our Selmo, Molla, Thrace Basin and Arpatepe exploration licenses and production leases, the development of other exploration properties in Turkey and Bulgaria, and general and administrative expense reductions and operational efficiencies.

Operations in Attractive Regions. We have focused our operations in countries that have established, yet underexplored, petroleum systems, have stable governments, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. 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 2012, we realized average prices of $102.55 per Bbl for our oil production and $8.68 per Mcf for our natural gas production. We also expect that our properties in Bulgaria will operate under favorable economic terms. We expect that future production in Bulgaria will be subject to royalty rates ranging from 2.5% to 30%, and corporate income tax rates of 10% after a one-year tax holiday.

Our Strategy

The following are key elements of our strategy:

Apply Modern Drilling and Completion Techniques in Turkey. Historically, the oil and natural gas exploration and production industry in Turkey has not used recent drilling and completion techniques. We expect to expand our application of modern techniques to our properties in Turkey. Modern 3D seismic acquisition, fracture stimulation and directional and horizontal drilling all provide opportunities to significantly increase production and grow reserves. In the fourth quarter of 2012, we completed our first two horizontal wells in Turkey on our Molla and Gaziantep exploration licenses. Building upon these successes, we expect our drilling campaign in southeastern Turkey during 2013 to be almost exclusively via horizontal drilling. Additionally, we successfully utilized fracture stimulation of new and existing wellbores on our Molla, Selmo and Thrace Basin licenses during 2012. We expect to continue employing fracture stimulation to allow the commercial development of reserves that would have not been commercial otherwise, as well as more efficiently develop existing proved reserves, most notably at Selmo.

Grow Production and Reserves in Turkey. Since 2009, we have completed a number of important acquisitions through which we have substantially grown our acreage and reserves and increased our production in Turkey. We also plan to increase our oil and natural gas production in Turkey through continuous drilling in Molla, Selmo and the Thrace Basin, the application of modern well stimulation techniques and the use of directional and horizontal drilling.

Expand Drilling Inventory. During 2012, we continued to gather 3D seismic data in the Thrace Basin and completed aeromagnetic and 2D seismic surveys in the Sivas Basin. The gathering of seismic and aeromagnetic data has continued to define and expand the future drilling inventory on our extensive acreage position. During 2013, we expect to complete more 3D seismic surveys covering our northern Molla licenses, as well as several additional areas of the Thrace Basin.

Accelerate Development Through Partnerships. We are currently seeking joint venture partners for our exploration acreage in Bulgaria and Turkey. Through farm-outs, we expect to accelerate development, mitigate exploration risk and reduce our share of capital commitments.

Our Properties and Operations

Summary of Geographic Areas of Operations

The following table shows net reserves information attributable to our principal geographic areas of operation as of December 31, 2012:

	Proved Developed Reserves (Mboe)	Proved Undeveloped Reserves (Mboe)	Total Proved Reserves (Mboe)	Probable Reserves (Mboe)	Possible Reserves (Mboe)
Turkey	6,436	5,094	11,530	9,958	32,586
Bulgaria	48	—	48	14	22
Total	6,484	5,094	11,578	9,972	32,608

In 2013, we plan to drill or participate in the drilling of approximately 40 new wells in the Thrace Basin of northwestern Turkey, 17 new wells in southeastern Turkey, one new well in central Turkey, and one new well in Bulgaria.

Turkey

As of May 1, 2013, we held interests in 39 onshore and offshore exploration licenses and 12 onshore production leases covering a total of 4.4 million gross acres (3.3 million net acres) in Turkey. As of December 31, 2012, we had total net proved reserves of 9,492 Mbbl of oil and 12,229 Mmcf of natural gas, net probable reserves of 7,946 Mbbl of oil and 12,074 Mmcf of natural gas and net possible reserves of 15,229 Mbbl of oil and 104,140 Mmcf of natural gas in Turkey. During 2012, we produced an average of approximately 4,505 net Boepd of oil and natural gas in Turkey. The following summarizes our core producing properties in Turkey:

Southeastern Turkey . Substantially all of our oil production is concentrated in southeastern Turkey, primarily in the Selmo, Goksu, Bahar and Arpatepe oil fields. These properties are located within the Zagros fold belt, which encompasses the oil fields of Iran and Iraq.

We hold a 100% working interest in the Selmo production lease. 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 2012, we drilled nine development wells and performed 10 fracture stimulations of existing wellbores on our Selmo production lease. For 2012, our net production of crude oil from the Selmo field was 813,322 Bbls at an average rate of approximately 2,222 Bbls per day. 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 field. At May 1, 2013, we had 48 producing wells in the Selmo field, and we plan to drill six wells at Selmo during 2013, five of which we expect to drill horizontally and one of which will be a deep vertical well.

We hold a 100% working interest in each of our three Molla exploration licenses, which contain the recently discovered Goksu and Bahar oil fields. In 2012, we completed the Goksu-2 and Goksu-3H wells in the Mardin formation. The Goksu-3H was the first horizontal well that we completed in Turkey, and the well has produced approximately 66,000 gross Bbls of oil as of May 1, 2013. To further evaluate the horizontal Mardin play concept in 2013, we anticipate drilling six horizontal wells and one vertical well on the Molla licenses.

During 2012, we also completed the Bahar-1 exploration well on one of our Molla exploration licenses. The Bahar-1 successfully evaluated the Mardin, Hazro and Bedinan formations, as well as the Dadas shale. In December 2012, we fracture stimulated the Bedinan formation in the Bahar-1. In addition to the Bedinan oil flow test, the Hazro formation in Bahar-1 was also tested. The Hazro exhibited oil and gas shows on the mud logs, which was then corroborated by open hole log analysis, and early results indicated productivity of approximately 150 Bbls of oil per day. In January 2013, full production from the well was resumed at a peak sales rate of

653 Bbls of oil per day, and the well has produced approximately 44,000 gross Bbls of oil as of May 1, 2013. In light of the Bahar-1 results, we plan to drill three horizontal wells targeting the Dadas shale and Bedinan sandstone during 2013, including the Bahar-2 exploration well, which we spud in January 2013. The Bahar-2 is planned as a horizontal well in the Bedinan sandstone, and we expect to complete the well with a multi-stage frac in the second half of 2013.

We hold a 50% working interest in each of our Arpatepe production lease and exploration license. In 2012, we drilled and completed the Arpatepe-6 well which started producing in mid-October 2012 at an initial gross rate of approximately 200 Bbls of oil per day. The Bati Arpatepe-1 well (50% working interest), which was drilled and funded by Aladdin Middle East, Ltd. (“Aladdin”), the operator of the Arpatepe production lease and exploration license, did not find commercial quantities of hydrocarbons and was plugged and abandoned. For 2012, our net production of crude oil from the Arpatepe field was 43,436 Bbls at an average rate of approximately 119 Bbls per day. At March 1, 2013, we had five producing wells on the Arpatepe production lease, and we plan to drill one well on the exploration license in 2013.

Thrace Basin . 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. We have accumulated significant onshore acreage in the Thrace Basin, which is located in northwestern Turkey near Istanbul.

For 2012, our net production of natural gas in the Thrace Basin was approximately 4,154 Mmcf, or approximately 11.4 Mmcf/d. For the fourth quarter of 2012, our net production of natural gas in the Thrace Basin was approximately 848 Mmcf, or approximately 9.2 Mmcf/d. In 2012, we drilled 24 exploration wells and 12 additional development wells on our Thrace Basin properties. As of May 1, 2013, we had 156 producing wells on our Thrace Basin properties, and we plan to drill approximately 36 new wells in 2013, including 17 wells in the Tekirdag field area development program, eight wells testing the Hayrabolu structure area, and 11 wells on other exploration licenses and production leases.

Central Basins . We have substantial exploration acreage in central Turkey. In February 2012, we entered into an agreement with Shell Upstream Turkey B.V. (“Shell”), pursuant to which Shell co-funded the acquisition of 1,187 kilometers of 2D seismic data and approximately 8,553 kilometers of airborne gravity, gradiometry and magnetic data in Turkey’s Sivas Basin, where we hold exploration licenses covering approximately 1.6 million acres. The agreement provided an option for Shell to farm into a 60% working interest in the exploration licenses after it assessed the data. In April 2013, Shell notified us that it elected not to exercise the option.

During 2012, we had initial success with horizontal drilling with the Alibey-1 well on our Gaziantep License 4607. The Alibey-1 well swabbed at an initial production rate of 150 Bbls of oil per day from the first stage of perforations before being temporarily shut-in due to winter weather conditions. We expect to complete the well and put it into production in the second quarter of 2013. We plan to drill one horizontal well on this license in 2013. During 2012, we drilled the Konak-1 well on our Gurun license in Central Turkey. The Konak-1 did not encounter economic levels of hydrocarbons and was plugged and abandoned.

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 acre (65,000 hectare) Koynare concession area (the “Koynare Concession Area”). 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. During 2012, the well produced a total of 3.1 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 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”). 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 performed an environmental impact assessment which the Bulgarian government must approve prior to granting the production concession. Pursuant to our agreement with LNG Energy, Ltd. (“LNG”), if we obtain a production concession over the Stefanetz Concession Area, LNG would fund an additional $12.5 million in exchange for a 50% working interest in the production concession.

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, we expect our conventional natural gas exploration, development and production activity in Bulgaria to resume in 2013. As long as the current legislation remains in effect, our unconventional natural gas exploration, development and production activities in Bulgaria will be significantly constrained.

Romania

As of May 1, 2013, we held a 50% non-operated working interest in the Sud Craiova onshore exploration license in western Romania. In 2012, the Romanian government temporarily suspended unconventional exploration of hydrocarbons, including fracture stimulation, pending a government review of unconventional drilling and completion techniques. As a result, on May 10, 2013, we and Sterling Resources Ltd. (“Sterling”), the operator of the license, notified the government that we were relinquishing the license.

Current Operations

As of May 1, 2013, we were producing an aggregate of approximately 2,785 net Bbls of oil per day, primarily from the Selmo production lease, Arpatepe production lease and the Molla exploration licenses, and approximately 7.9 net Mmcf/d of natural gas, primarily from our various Thrace Basin production leases and exploration licenses. As of May 1, 2013, we were engaged in the following drilling and exploration activities:

Turkey . We were drilling one gross and net horizontal well on our Molla exploration licenses, one gross and net well at the Bahar oilfield, and one gross well (0.4 net wells) in the Thrace Basin. In addition, we were completing one gross well (0.4 net wells) in the Thrace Basin and preparing two gross wells (0.8 net wells) for fracture stimulation in the Thrace Basin.

Bulgaria. We were coordinating our 2013 Koynare Concession Area and Aglen work programs with the Bulgarian Ministry of Energy, Economy and Tourism.

Planned Operations

We continue to actively explore and develop our existing oil and natural gas properties in Turkey and evaluate the opportunities for further activities in Bulgaria. Our success will depend in part on discovering additional hydrocarbons in commercial quantities and then bringing these discoveries into production. In 2013, we are focused on accomplishing the following objectives:

- *Increase Production* . We plan to increase our oil and natural gas production in Turkey through exploration and development on our Molla, Thrace Basin, Selmo and Arpatepe licenses and production leases, including the application of fracture stimulation techniques and horizontal drilling.
- *Continue to Expand Fracture Stimulation Program* . In 2012, our Thrace Basin fracture simulation program tested and defined deeper intervals and provided important lessons regarding frac design. We plan to expand our application of fracture stimulation techniques through a development program in the Tekirdag field area and to additional areas in the Thrace Basin. Additionally, we expect to expand the

application of the process in several of our licenses in southeastern Turkey. We anticipate that employing fracture stimulation techniques will result in the commercial development of production and reserves that would have not been commercial otherwise.

- *Expand the Use of Horizontal Drilling* . In 2012, we had initial success with horizontal drilling with our Goksu-3H well on our Molla licenses and the Alibey-1 well on our Gaziantep licenses. During 2013, we anticipate our drilling in southeastern Turkey will include extensive use of horizontal drilling techniques, including nine wells on our Molla licenses, five wells at Selmo, and one well on our Gaziantep licenses.
- *Accelerate Development Through Partnerships* . In an effort to increase the pace of exploration activity, share exploration risk, and reduce our share of the capital commitments necessary to carry forward the exploration of our extensive acreage position, we are currently seeking joint venture partners for our exploration acreage in Bulgaria and Turkey.

We expect our capital expenditures for 2013 to be approximately $131.0 million. We expect capital expenditures during 2013 to consist of approximately $101.0 million of drilling and completion expense (over 60 gross wells), $19.0 million of seismic expense and $11.0 million of infrastructure and other expense. Of these expenditures, we expect to spend approximately 32% on the Thrace Basin in Turkey, devoted to developing conventional and unconventional natural gas production, building infrastructure and acquiring seismic data. Most of the remaining 68% of these anticipated expenditures is expected to be directed to southeastern Turkey, devoted to drilling developmental and exploratory oil wells at Selmo, Arpatepe, Gaziantep and Molla. We expect cash on hand, borrowings from our Amended and Restated Credit Facility and cash flow from operations will be sufficient to fund our capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. If we successfully complete a joint venture transaction during 2013, we anticipate increasing our drilling activity. Our projected 2013 capital expenditure budget is subject to change.

Exploration, Development and Production. We currently plan to execute the following drilling and exploration activities during 2013:

Turkey. We plan to drill approximately 60 gross wells, of which 15 are expected to be drilled horizontally and approximately 50% of which will be fracture stimulated. We also plan to construct the infrastructure necessary to produce and sell oil and natural gas from the productive wells we drill.

Bulgaria . As of May 1, 2013, we were coordinating our 2013 Koynare Concession Area and Aglen work programs with the Bulgarian Ministry of Energy, Economy and Tourism. Our 2013 corporate capital expenditure budget includes amounts for drilling and completing the Deventci-R2 well.

Principal Capital Expenditures and Divestitures

The following table sets forth our principal capital expenditures and divestitures during 2012 (in thousands):

Expenditure Type	Year Ended December 31, 2012
Oil and natural gas properties	
Proved	$ 36,465
Unproved	44,691
Equipment and other property	668
Total capital expenditures	$ 81,824

Divestiture Type	Year Ended December 31, 2012
Net proceeds from sale of oilfield services business	$ 168,511
Net book value of oilfield services business	132,512
Gain on sale of oilfield services business	$ 35,999

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: Bulgaria, Romania and Turkey. For financial information about our operating segments and geographic areas, refer to "Note 14—Segment information" to our consolidated financial statements.

Customers

Oil . During 2012, 85.7% 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 2012, we sold $91.8 million of oil to TUPRAS, representing approximately 63.8% 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.

Natural Gas . During 2012, no purchasers of our natural gas accounted for 10% or more of our total net 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
- acquiring the equipment and 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 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 are 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 re-entering and 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 and 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 and Selmo, we have access to water resources which we believe will be adequate to execute our fracture stimulation program in 2013. 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—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—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;
- 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, Bulgaria or Romania. 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, potentially resulting 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 operation 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 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 with a combined annual limit of $20.0 million per occurrence and $30.0 million in the aggregate. These insurance policies contain maximum policy limits and are subject to customary exclusions and limitations. Our pollution insurance, which is part of our general liability policy, has a per occurrence limit of $1.0 million and aggregate annual limit of $2.0 million. 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, including Viking International and Viking Geophysical, 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 authorised 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 authorised share capital and share premium account on August 31st 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 May 1, 2013, we employed 291 people. Approximately 55 of our employees at one of our Turkish subsidiaries were represented by collective bargaining agreements with the Petroleum, Chemical and Rubber Workers Union of Turkey (“PETROL-IS”). We consider our employee relations to be satisfactory.

Formation

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

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), are made available free of charge on our website at www.transatlanticpetroleum.com as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

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

We have incurred substantial losses in prior years. During 2012, we generated a net loss from continuing operations of $6.4 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 the 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 decrease our net income, cash provided by operating activities and results of operations, 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.

We have concentrated current production of oil in the Selmo oil field, the majority of which is sold to one customer.

During 2012, we derived 85.7% of our oil production from the Selmo oil field in southeastern Turkey. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, litigation or interruption of the processing or transportation of oil, natural gas or natural gas liquids. In addition, we are currently in litigation with a group of villagers who live around the Selmo oil field and who claim ownership of a portion of the surface rights at Selmo.

In addition, TPAO, the national oil company of Turkey, and TUPRAS, a privately owned oil refinery in Turkey, purchase all of our oil production from the Selmo field. TUPRAS purchases the majority of our oil production from Selmo, representing 63.8% of our total revenues in 2012. If either of these companies fails to purchase our oil production, our results of operations could be materially and adversely affected.

We could lose permits or licenses on certain of our properties 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, 2012, of our total net undeveloped acreage, including our Sud Craiova license, 30.6% and 55.7% will expire during 2013 and 2014, 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.

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

Virtually all of our international operations are performed in the emerging markets of Turkey and Bulgaria, 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 and of the other countries in which we operate affecting foreign trade, taxation and investment;
- 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 2012, we derived 85.7% 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 or economic problems, terrorist attacks, insurgencies or civil unrest. Recently, Turkey and Syria have exchanged artillery fire, and in 2012 Syria shot down a Turkish fighter jet, raising the possibility of conflict between the countries. If any of these events, conditions or conflicts occurs, we may be unable to access the locations where we conduct operations. 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.

Our Amended and Restated Credit Facility contains various covenants that limit our management's discretion in the operation of our business and can 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 Amended and Restated Credit Facility may adversely affect our ability to finance future operations or capital needs or to engage in other business activities. Our Amended and Restated 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 Amended and Restated 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 Amended and Restated Credit Facility and could result in an event of default under the Amended and Restated Credit Facility.

An event of default under the Amended and Restated 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, Ltd. ("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 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 Amended and Restated 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 Amended and Restated Credit Facility, our business, financial condition and results of operations may be materially and adversely affected.

We have identified material weaknesses in our internal control over financial reporting. These material weaknesses, if not corrected, could affect the reliability of our financial statements and have other adverse consequences.

Under Section 404 of the Sarbanes-Oxley Act of 2002, we are required to furnish a report by our management on internal control over financial reporting. This report must contain, among other matters, an assessment of the effectiveness of our internal control over financial reporting, including a statement as to whether or not our internal control over financial reporting is effective. This assessment must include disclosure of any material weaknesses in our internal control over financial reporting identified by our management. In addition, the report must contain a statement that our auditors have issued an attestation report on management's assessment of such internal control over financial reporting.

We have identified material weaknesses in our internal control over financial reporting as of December 31, 2012, as disclosed in "Item 9A. Controls and Procedures". Failure to have effective internal controls could lead to a misstatement of our financial statements or prevent us from filing our financial statements in a timely manner. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial statements, our business decision processes may be adversely affected, our business and operating results could be harmed, investors could lose confidence in our reported financial information, the price of our common shares could decrease and our ability to obtain additional financing, or additional financing on favorable terms, could be adversely affected. In addition, failure to maintain effective internal control over financial reporting could result in investigations or sanctions by regulatory authorities.

We intend to take further action to remediate the material weaknesses and improve the effectiveness of our internal control over financial reporting. However, we can give no assurances that the measures we may take will remediate the material weaknesses identified or that any additional material weaknesses will not arise in the future due to our failure to implement and maintain adequate internal control over financial reporting. In addition, even if we are successful in strengthening our controls and procedures, those controls and procedures may not be adequate to prevent or identify irregularities or ensure the fair presentation of our financial statements included in our periodic reports filed with the SEC.

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

As of May 1, 2013, approximately 55 of our employees at one of our Turkish subsidiaries were represented by collective bargaining agreements with the Petroleum, Chemical and Rubber Workers Union of 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

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

Any material inaccuracies in our reserve 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 reserve 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 and Thrace Basin Natural Gas (Turkiye) Corporation (“TBNG”) 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.

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 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, 2012, approximately 44% 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, 2012, we also had a significant amount of unproved reserves, which consist of probable and possible reserves. There is significant uncertainty attached to unproved reserve 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 planned 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 the Thrace Basin and 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 and a temporary moratorium on unconventional drilling activities in Romania have placed restrictions on our fracture stimulation activities, causing us to suspend our fracture stimulation activities in Bulgaria and to relinquish our Sud Craiova license in Romania. 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.

Drilling for oil and natural gas is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our 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 uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining drilling rigs, equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as flooding;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

Significant or prolonged delays or cancellations in our scheduled drilling projects could materially adversely affect our results of operations.

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
- acquiring the equipment and 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.

We may not be able to complete the exploration, development or production of any, or a significant portion of, the oil and natural gas interests covered by our leases or licenses before they expire.

Each license or lease under which we operate has a fixed term. We may be unable to complete our exploration, development or production efforts prior to the expiration of licenses or leases. Failure to obtain government approval for a license or lease or an extension of the license or lease, be granted a new exploration license or lease or obtain a license or lease covering a sufficiently large area could prevent us from, or limit us in, continuing to explore, develop or produce a significant portion of the oil and natural gas interests covered by the license or lease. The determination of the amount of acreage to be covered by the production license or lease is in the discretion of the respective governments.

Political and economic instability or fundamental changes in the leadership or in the structure of the governments in the jurisdictions in which we operate could have a material negative impact on our company.

Our foreign property interests and foreign operations may be affected by political and economic risks. These risks include war and civil disturbances, political instability, currency restrictions and exchange rate fluctuations, labor problems and high rates of inflation. In addition, local, regional and world events could cause the jurisdictions in which we operate to change the petroleum laws, tax laws, foreign investment laws, or to revise their policies in a manner that renders our current and future projects unprofitable. Further, we are subject to risks in the foreign jurisdictions in which we operate of the nationalization of the oil and natural gas industry, expropriation of property or other restrictions and penalties on foreign-owned entities, which could render our projects unprofitable or could prevent us from selling our assets or operating our business. The occurrence of any such fundamental change could have a material adverse effect on our business, financial condition and results of operations.

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 May 1, 2013, Mr. Mitchell beneficially owned approximately 40% 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 and 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.

Item 1B. Unresolved Staff Comments

Not applicable.

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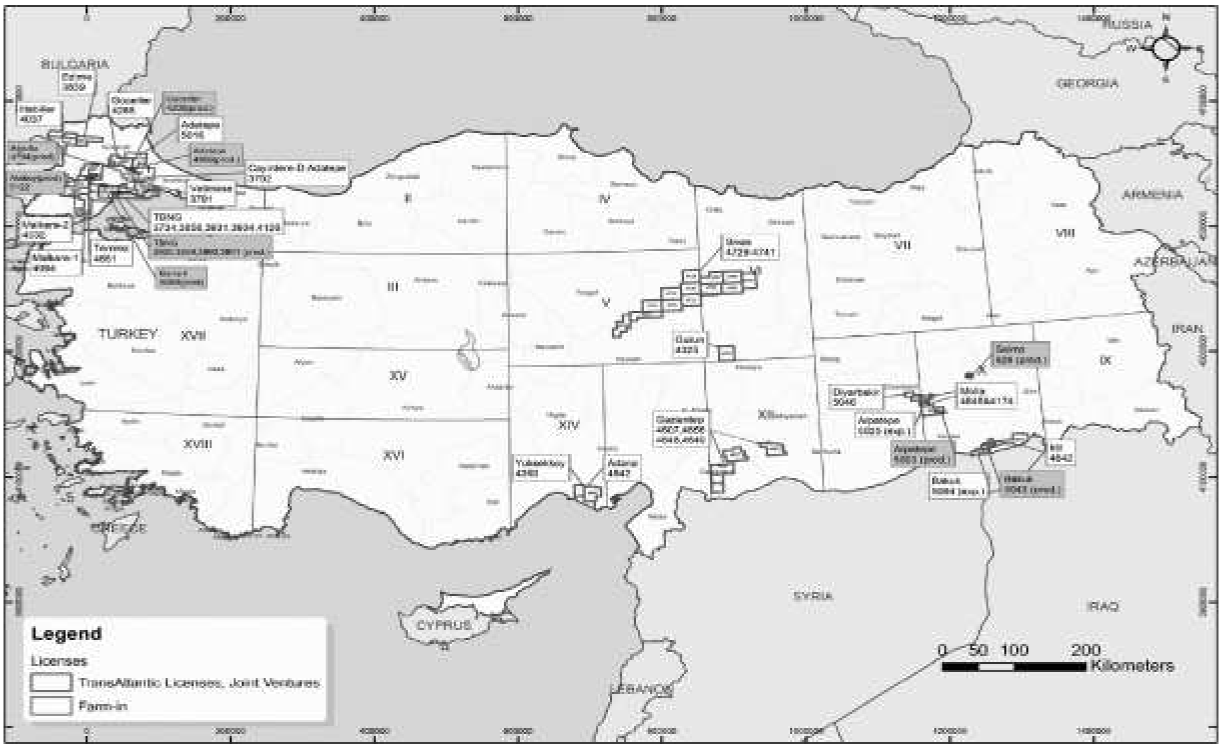
Item 2. Properties

Turkey

General. As of May 1, 2013, we held interests in 39 onshore and offshore exploration licenses and 12 onshore production leases covering a total of approximately 4.4 million gross acres (approximately 3.3 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, 2012, we had total net proved reserves of 9,492 Mbbl of oil and 12,229 Mmcf of natural gas, net probable reserves of 7,946 Mbbl of oil and 12,074 Mmcf of natural gas and net possible reserves of 15,229 Mbbl of oil and 104,140 Mmcf of natural gas in Turkey.

Equipment Yards. As of May 1, 2013, we leased equipment yards in Muratli, Diyarbakir and Tekirdag and owned equipment yards at Selmo and Edirne.

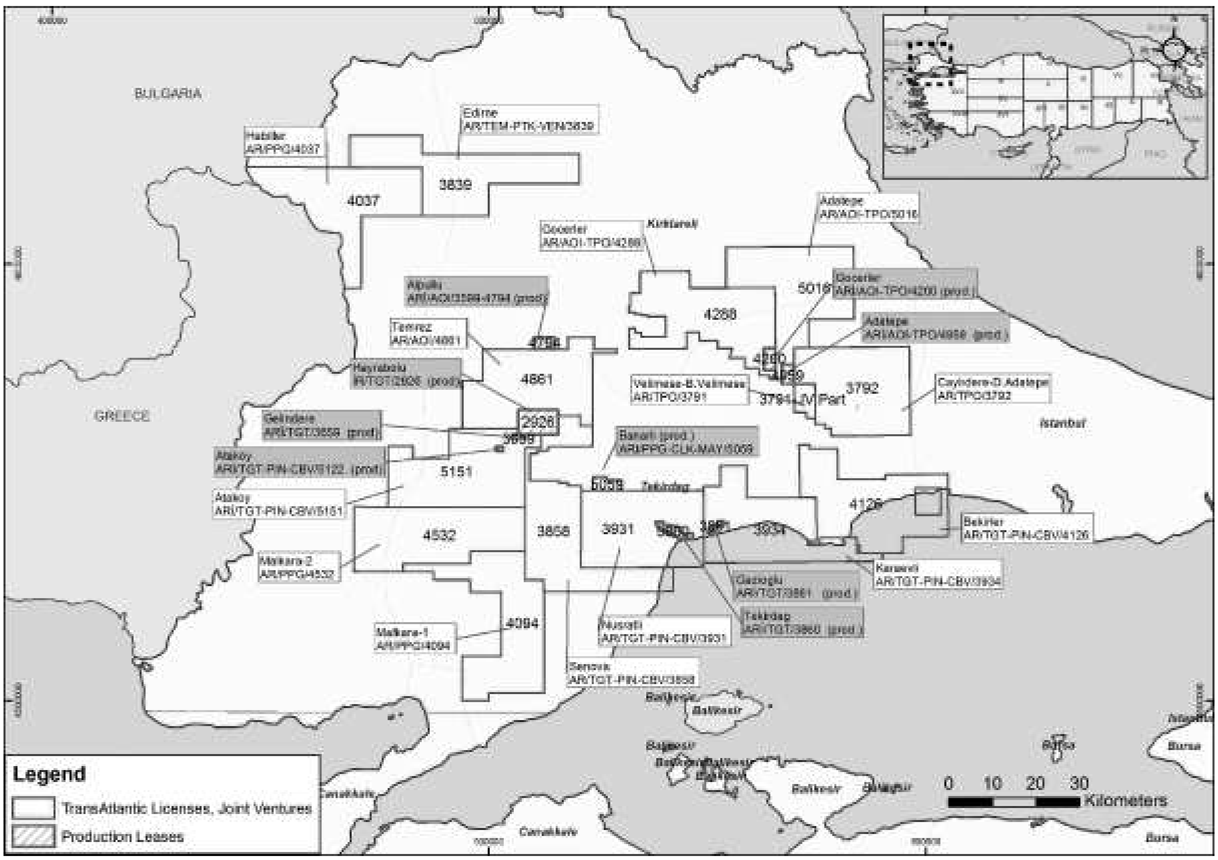
Commercial Terms. Turkey’s fiscal regime for oil and natural gas licenses is presently comprised of royalties and income tax. The royalty rate is 12.5% and the corporate income tax rate is 20%. Our revenue from the Selmo oil field is subject to an additional 10% royalty, which is offset by the amount 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.

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.

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 petroleum. 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 hectares under the license.

Once a discovery is made, the license holder applies to convert the area, not to exceed 25,000 hectares, 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 ten years each. Annual rentals are due based on the hectares comprising 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.

Thrace Basin. The following map shows our interests in the Thrace Basin in northwestern Turkey:



Edirne (License 3839) and Habiller (License 4037) . We own a 55% working interest in License 3839 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 May 1, 2013, we had nine producing wells on the Edirne and Habiller licenses. We are the operator of Licenses 3839 and 4037, which expire in October 2014 and March 2016, respectively.

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. Upon the acquisition of Amity in August 2010, we commenced limited natural gas sales from the Alpullu production lease. As of May 1, 2013, we had two producing wells on the Alpullu production lease. We are the operator of Production Lease 4794 and License 4861, which expire in September 2028 and December 2014, respectively.

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. Upon the acquisition of Amity in August 2010, we commenced limited natural gas sales from the Gocerler production lease. As of May 1, 2013, we had two producing wells on the Gocerler production lease and one producing well on License 4288. We are the operator of Production Lease 4200 and License 4288, which expire in March 2024 and August 2013, respectively. We have applied for a two-year extension on License 4288.

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. Upon the acquisition of Amity in August 2010, we commenced limited natural gas sales from the Adatepe production lease. As of May 1, 2013, we had seven producing wells on the Adatepe production lease. We are the operator of Production Lease 4959 and License 5016, which expire in September 2031 and January 2017, respectively.

Malkara (Licenses 4094 and 4532). We own a 100% working interest in Licenses 4094 and 4532, which cover an aggregate of approximately 242,000 acres. The licenses are subject to a 50% farm-in right to Valeura Energy, Ltd. ("Valeura") in return for the completion of certain work commitments. We are the operator of Licenses 4094 and 4532, which expire in September 2013 and January 2015, respectively. We plan to apply for a three-year extension on License 4094 if we establish commercial production prior to the expiration of the license.

Banarli (Production Lease 5059). We own a 50% working interest in Production Lease 5059, which covers approximately 4,609 gross acres. As of May 1, 2013, we had one producing well on the Banarli production lease. We are the operator of Production Lease 5059, which expires in February 2032.

Tekirdag (Production Lease 3860), Gazioglu (Production Lease 3861) and Nusratli (License 3931) . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in Production Leases 3860 and 3861 and License 3931, which cover an aggregate of approximately 112,000 gross acres. As of May 1, 2013, we had 52 producing wells on the Tekirdag and Gazioglu production leases and 85 producing wells on the Nusratli license. We are the operator of Production Leases 3860 and 3861 and License 3931, which expire in December 2023, December 2021 and November 2015, respectively.

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 May 1, 2013, we had eight producing wells on the Hayrabolu production lease. We are the operator of Production Lease 2926, which expires in February 2020.

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 May 1, 2013, our producing wells on the Gelindere lease were temporarily shut in. We are the operator of Production Lease 3659, which expires in June 2017.

Karaevli (License 3934) . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3934, which covers approximately 56,000 gross acres. As of May 1, 2013, we had five producing wells on the Karaevli exploration license. We are the operator of License 3934, which expires in November 2015.

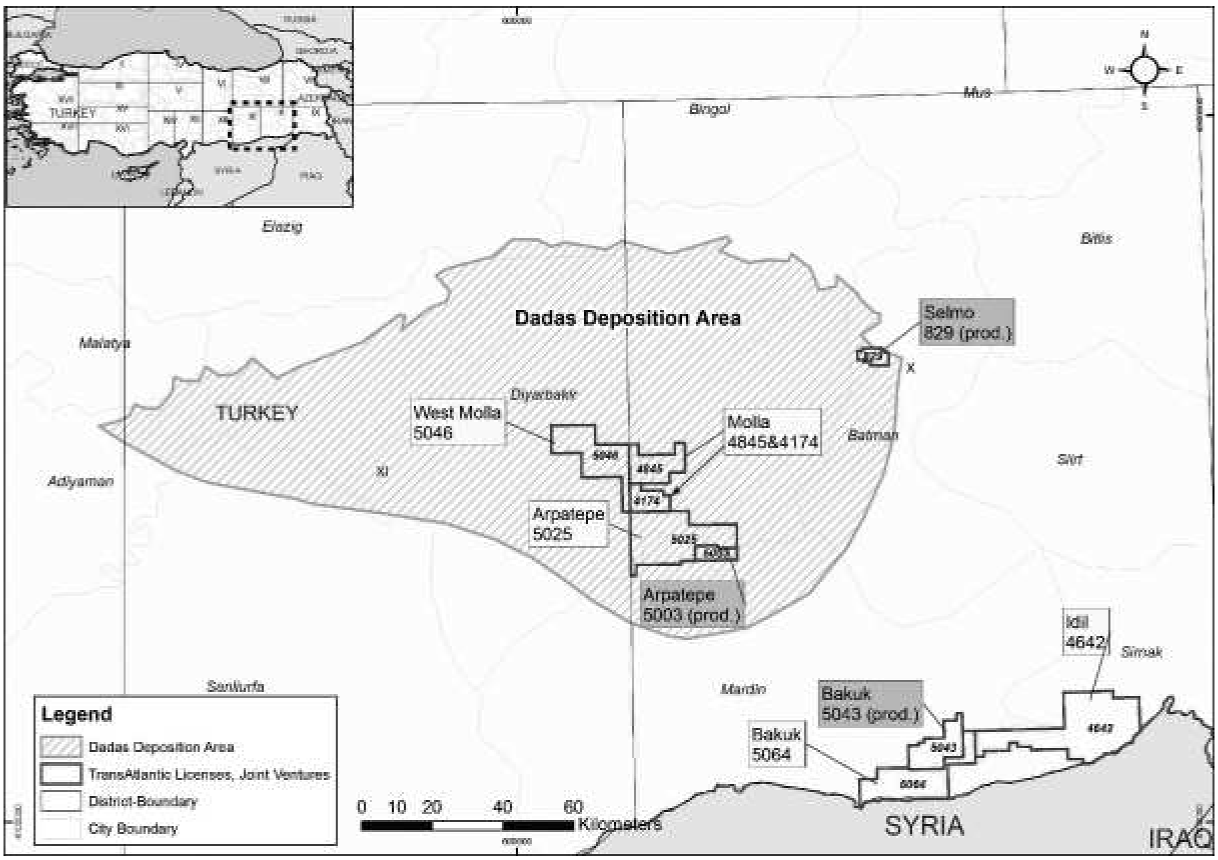
Senova (License 3858) . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 3858, which covers approximately 122,000 gross acres. We are the operator of License 3858, which expires in May 2015.

Atakoy (Production Lease 5122 and License 5151) . 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 of the original 121,000 acres of License 3734. As of May 1, 2013, we had 11 producing wells on the Atakoy production lease. We are the operator of Production Lease 5122, which expires in November 2032. In November 2012, we applied to renew the remaining acreage on the original License 3734, now known as License 5151, and that application is pending with the GDPA.

Bekirler (License 4126) . We own a 41.5% working interest, subject to a 0.415% overriding royalty interest, in License 4126, which covers approximately 75,000 gross acres. In 2013, we plan to perform workovers of existing wells on this license in order to establish commercial production, which would allow us to extend the license an additional three years. We are the operator of License 4126, which expires in December 2013.

Velimese (License 3791) and Cayirdere (License 3792). We own a 50% working interest in Licenses 3791 and 3792, which cover an aggregate of approximately 125,000 gross acres. As of May 1, 2013, we had seven producing wells on the Cayirdere exploration license and no producing wells on the Velimese exploration license. TPAO is the operator of Licenses 3791 and 3792, which expire in August 2013 and October 2013, respectively. We plan to apply for production leases on each of these licenses and reapply for exploration licenses covering the remaining acreage in 2013.

Southeastern Turkey. The following map shows our interests in southeastern Turkey:



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 May 1, 2013, there were 48 producing wells on the Selmo production lease. For 2012, our net production of oil in the Selmo field was approximately 813,322 Bbls of oil, at an average rate of approximately 2,222 Bbls per day. We are the operator of Production Lease 829, which expires in June 2015. We plan to submit an application to extend the expiration date of Production Lease 829 to June 2025.

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 acres adjacent to the northern border of our former License 3118 (now Production Lease 3118-5003). In 2012, we drilled the Goksu-3H and Bahar-1 wells, which have produced approximately 66,000 gross Bbls and 44,000 gross Bbls of oil, respectively, as of May 1, 2013. We are the operator of Licenses 4174, 4845 and 5046, which expire in June 2014, March 2015 and June 2016, respectively.

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 84,600 gross acres, respectively. For 2012, our net production of oil from the Arpatepe field was approximately 43,436 Bbls of oil, at an average rate of approximately 119 Bbls per day. As of May 1, 2013, we had five producing wells on the Arpatepe production lease. Aladdin is the operator of Production Lease 5003 and License 5025, which expire in November 2028 and February 2016, respectively.

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 34,000 gross acres. As of May 1, 2013, there was one producing well on the Bakuk production lease. Tiway Turkey, Ltd. (“Tiway”) is the operator of License 5064 and Production Lease 5043, which expire in June 2016 and January 2032, respectively.

Idil (License 4642) . We own a 50% working interest in License 4642, which covers approximately 123,000 gross acres. We plan to drill one well on this license in 2013. We are the operator of License 4642, which expires in October 2014.

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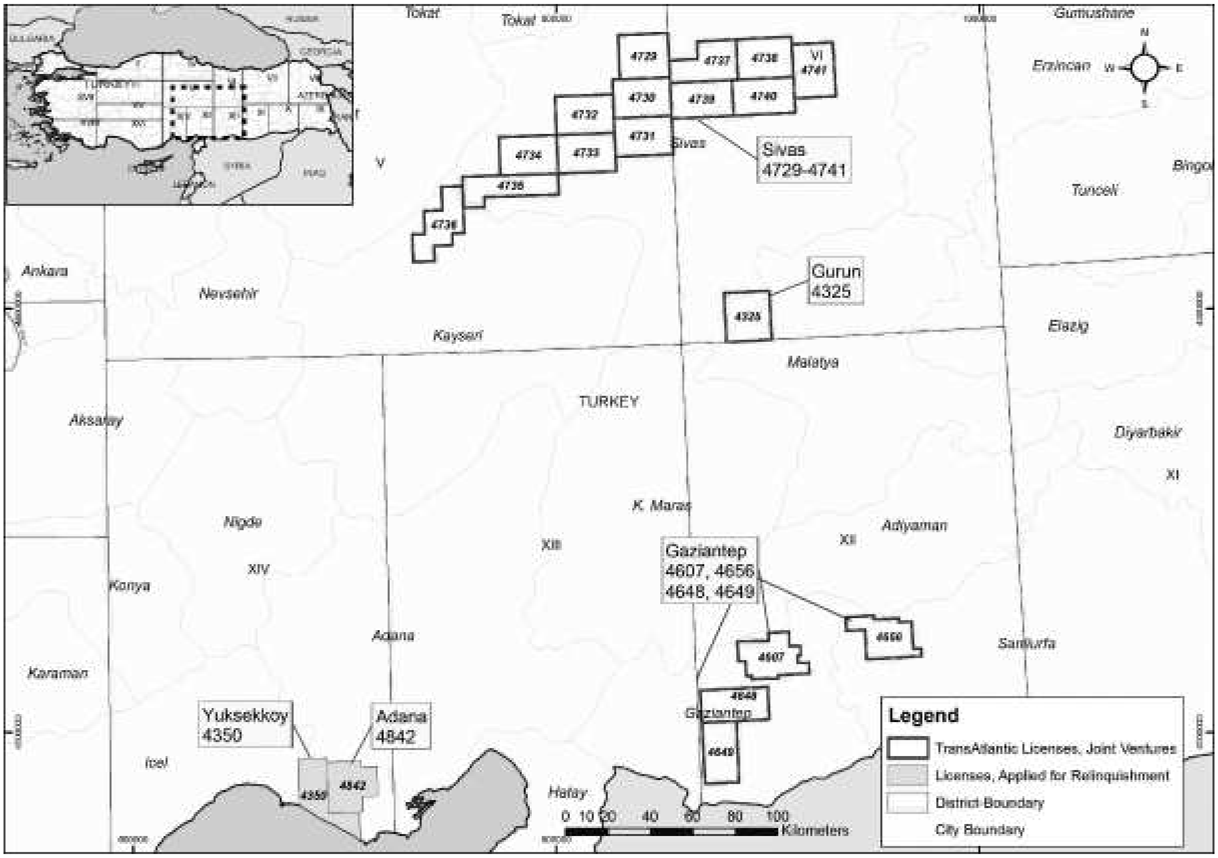
Central Basins. Our exploration licenses in central Turkey cover largely unexplored tertiary basins. We are currently seeking partners for these exploration licenses. Through farm-outs, we expect to reduce our exploration risk and accelerate the exploration and development activities on the farmed out properties. We intend to remain as operator of the properties that we farm-out. The following map shows our interests in central Turkey:



Yuksekkoy (Licenses 4350) and Adana (License 4842) . We own a 100% working interest in Licenses 4350 and 4842, which cover an aggregate of approximately 242,000 acres in the Adana area of central Turkey. We are the operator of Licenses 4350 and 4842, which expire in March 2014 and June 2015, respectively. Based on reviews of the prospectivity within these licenses, we have applied to relinquish both of these licenses as of February 12, 2013.

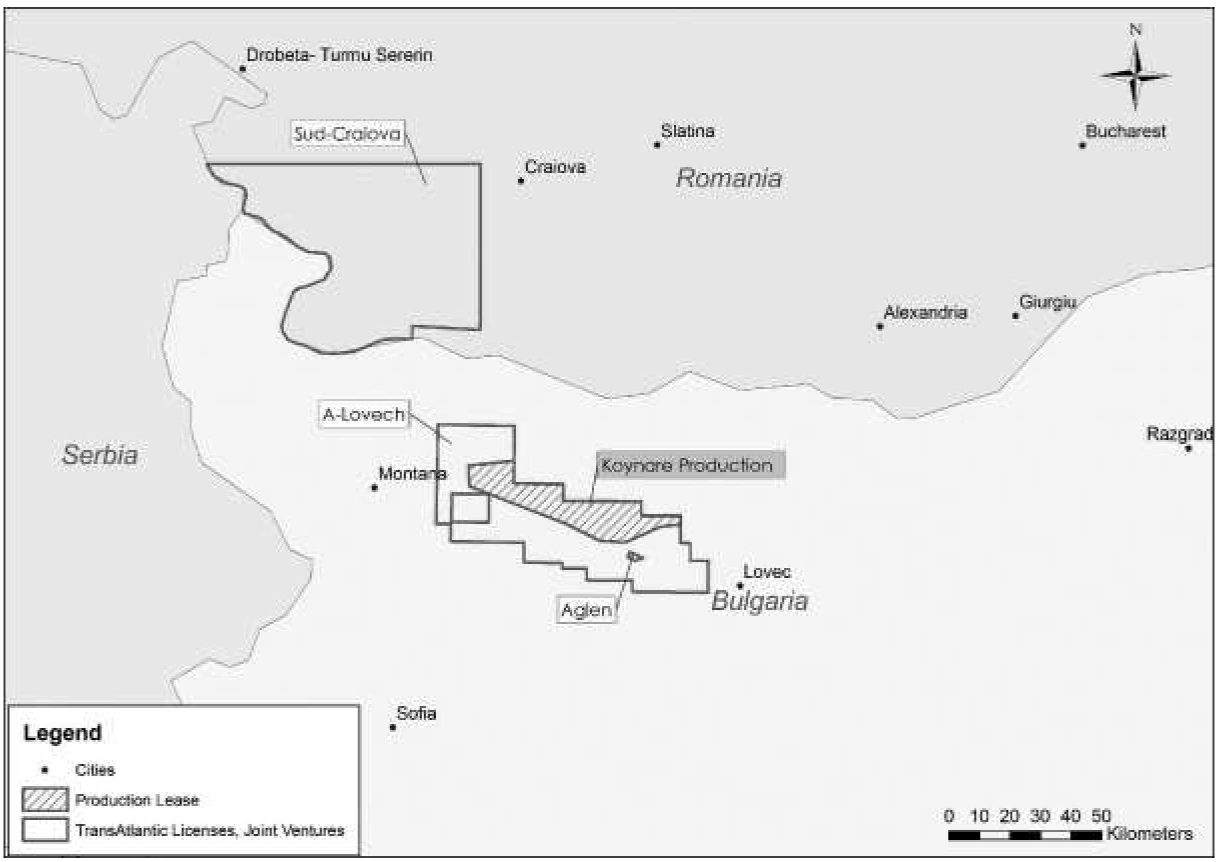
Sivas Basin (Licenses 4729, 4730, 4731, 4732, 4733, 4734, 4735, 4736, 4737, 4738, 4739, 4740 and 4741) . We own a 100% working interest in Licenses 4729, 4730, 4731, 4732, 4733, 4734, 4735, 4736, 4737, 4738, 4739, 4740 and 4741, which cover an aggregate of approximately 1.6 million acres in central Turkey. These licenses are in a large, relatively unexplored tertiary basin. In 2012, pursuant to our farm-out agreement with Shell, we acquired 2D seismic and airborne gravity data over the licenses. We are the operator of the licenses, which expire in December 2014.

Gurun (License 4325) . We own a 90% working interest in License 4325, which covers approximately 122,000 gross acres in central Turkey. In April 2009, we farmed-in for a 90% interest in License 4325 for cash consideration and the obligation to carry a 10% interest in the first well drilled. During 2012, we drilled the Konak-1 exploration well, which did not encounter economic levels of hydrocarbons. We are the operator of License 4325, which expires in February 2014.

Gaziantep (Licenses 4607, 4648, 4649 and 4656) . We own a 62.5% working interest in Licenses 4607, 4648, 4649 and 4656 (subject to a 0.78% overriding royalty interest), which cover an aggregate of approximately 488,000 gross acres near the Turkish border with Syria. During 2012, we drilled the Alibey-1 exploration well, which was our first horizontal well to discover oil. We are the operator of these licenses, which expire in October 2013, except for License 4607, which expires in August 2013.

Bulgaria

General. As of May 1, 2013, we held interests in one onshore exploration permit and one 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 and Romania at December 31, 2012:



Reserves. As of December 31, 2012, we had total net proved reserves of 9 Mbbl of oil and 234 Mmcf of natural gas, net probable reserves of 3 Mbbl of oil and 71 Mmcf of natural gas and net possible reserves of 4 Mbbl of oil and 107 Mmcf of natural gas 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 30 Bulgarian Lev (approximately $20 at March 1, 2013) per square kilometer, or 45 Bulgarian Lev (approximately $30 at March 1, 2013) 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, 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 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. We expect to resume drilling the Deventci-R2 well in 2013. As of May 1, 2013, we were coordinating our 2013 Koynare Concession Area work program with the Bulgarian Ministry of Energy, Economy and Tourism. We are the operator of the Koynare production concession, which expires in 2047.

Stefenetz. In November 2011, we initiated the application procedure 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 formation 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 LNG pursuant to which LNG funded the drilling of an exploration well on the Stefenetz Concession Area to core and test the Etropole 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 LNG are evaluating the core data and developing a conventional completion program for the Peshtene-R11 well. If the well is successful and we obtain a production concession over the Stefenetz Concession Area, LNG would fund up to an additional $12.5 million in exchange for a 50% working interest in the production concession.

Aglen. We own a 100% working interest, subject to a 1% overriding royalty interest, in 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. The Aglen permit contains a prospective deep natural gas field that produced approximately 9.0 Bcf of natural gas before being abandoned in the late 1990s. We are the operator of the Aglen permit, which was set to expire in April 2012. Due to the Bulgarian government's January 2012 legislation, a force majeure event was recognized by the government. As of May 1, 2013, we were coordinating our Aglen work program with the Bulgarian Ministry of Energy, Economy and Tourism.

Romania

General. As of May 1, 2013, we held a 50% working interest in Sud Craiova Block E III-7, which covers approximately 1.0 million gross acres in western Romania. Sterling is the operator of the Sud Craiova license, which was due to expire in December 2013. In 2012, the Romanian government temporarily suspended unconventional exploration of hydrocarbons, including fracture stimulation, pending a government review of unconventional drilling and completion techniques. As a result, on May 10, 2013, we and Sterling notified the government that we were relinquishing the license. As of December 31, 2012, there were no reserves associated with our Romanian properties. See "—Bulgaria—General" for a map showing our former interest in Romania.

Summary of Oil and Natural Gas Reserves

The following table summarizes our net proved, probable and possible reserves at December 31, 2012 in accordance with the rules and regulations of the SEC.

	Reserves		
Reserves Category	Oil and Condensate (Mbbl)	Natural Gas (Mmcf)	Total (Mboe)
Proved Reserves			
Proved Developed	5,132	8,115	6,484
Proved Undeveloped	4,369	4,348	5,094
Total Proved	9,501	12,463	11,578
Probable Reserves	7,948	12,145	9,972
Possible Reserves	15,233	104,247	32,608

Value of Proved Reserves

The following table shows our estimated future net revenue, PV-10 and Standardized Measure as of December 31, 2012:

(in thousands)	
Future net revenue	$742,152
Total PV-10 (1)	$511,078
Total Standardized Measure	$435,877

(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	$ 511,078
Future income taxes	(106,411)
Discount of future income taxes at 10% per annum	31,210
Standardized Measure	$ 435,877

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, 2012, our estimated proved reserves were 11,578 Mboe, a decrease of 13.7% compared to 13,419 Mboe at December 31, 2011. During 2012, we added estimated proved reserves of 2,303 Mboe through extensions and discoveries driven by our 2012 drilling activity in Turkey. These increases were offset by production volumes of 1,655 Mboe and performance revisions in existing producing wells of 2,489 Mboe. The estimated undiscounted capital costs associated with our proved reserves is $93.3 million.

Proved Undeveloped Reserves

At December 31, 2012, our estimated proved undeveloped reserves were 5,094 Mboe, a decrease of 19.1% compared to 6,293 Mboe at December 31, 2011. This decrease in proved undeveloped reserves was primarily attributable to revisions for existing undeveloped reserves in Selmo to reflect the results of recent new wells. During 2012, we incurred $19.9 million in capital expenditures to drill and complete 14 proved undeveloped wells. At December 31, 2012, no material amounts of proved undeveloped reserves remained undeveloped for five years or more after they were initially disclosed as proved undeveloped reserves. We intend to convert the proved undeveloped reserves disclosed as of December 31, 2012 to proved developed reserves within five years of the date they were initially disclosed as proved undeveloped reserves.

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.

At December 31, 2012, our estimated probable reserves were 9,972 Mboe, an increase of 44.3% compared to 6,912 Mboe at December 31, 2011. This increase in probable reserves was primarily attributable to the Bahar and Goksu discoveries on the Molla licenses.

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.

At December 31, 2012, our estimated possible reserves were 32,608 Mboe, an increase of 11.7% compared to 29,194 Mboe at December 31, 2011. This increase in possible reserves was primarily attributable to the Bahar and Goksu discoveries in the Molla licenses.

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 an outside independent engineering firm 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. Our internal audit department has tested the processes and controls regarding our reserves estimates for 2012. Senior management reviews and approves our reserve estimates, whether prepared internally or by third parties. In addition, our audit committee serves as our reserves committee and is composed of three outside directors, all of whom have experience in the review of energy company reserves evaluations. The audit committee reviews the final reserves estimate and also meets with representatives from the outside engineering firm to discuss their process and findings.

Oil and Natural Gas Reserves under U.S. Law

In the United States, we are required to disclose proved reserves, and we are permitted to disclose probable and possible reserves, using the standards contained in Rule 4-10(a) of the SEC's Regulation S-X. The estimates of proved, probable and possible reserves presented as of December 31, 2012 have been prepared by DeGolyer and MacNaughton, our external engineers. The technical person at DeGolyer and MacNaughton that is primarily responsible for overseeing the preparation of our reserves estimates is a Registered Professional Engineer in the State of Texas and has a Bachelor of Science degree in Mechanical Engineering from Kansas State University. He has over 30 years of experience in oil and natural gas reservoir studies and evaluations and is a member of the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with DeGolyer and MacNaughton to ensure the integrity, accuracy and timeliness of data furnished to them for the preparation of their reserves estimates. We retain a third-party consultant as the technical person primarily responsible for overseeing our reserve estimation process. She has a Bachelor of Science degree in Petroleum Engineering and Geology from Texas A&M University. She has over 30 years of experience in the oil and natural gas industry, including experience in production and reservoir engineering, and is a member of multiple professional organizations.

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 "Note 21—Supplemental oil and natural gas reserves and standardized measure 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, 2012 included a detailed review 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.

Oil and Natural Gas Reserves under Canadian Law

As a reporting issuer under Alberta, British Columbia and Ontario securities laws, we are required under Canadian law to comply with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") implemented by the members of the Canadian Securities Administrators in all of our reserves related disclosures. DeGolyer and MacNaughton evaluated the Company's reserves as of December 31, 2012, 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 Production

The following table sets forth our net production of oil and natural gas for 2012, 2011 and 2010:

	Net Production (1)		
Year	**Oil (2) (Bbls)**	**Natural Gas (Mcf)**	**Total (Boe)**
2012			
Turkey	947,998(3)	4,204,329	1,648,720
Bulgaria	641	33,531	6,230
2011			
Turkey	889,574(3)	4,610,537	1,657,997
Bulgaria	1,171	45,692	8,786
2010			
Turkey	689,823(3)	1,707,421	974,393

(1) Does not include nominal production from properties in other countries.
(2) "Oil" volumes include condensate (light oil) and medium crude oil.
(3) During 2012, 2011 and 2010, our net production of oil in the Selmo oil field was 813,322 Bbls, 838,615 Bbls and 411,964 Bbls, respectively.

Production Prices 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 2012, 2011 and 2010:

	2012	2011	2010
Turkey			
Average Sales Price			
Oil ($/Bbl)	$102.60	$100.26	$80.01
Natural Gas ($/Mcf)	$ 8.72	$ 7.08	$ 7.63
Unit Costs			
Production ($/Boe)	$ 10.69	$ 10.22	$20.48
Bulgaria			
Average Sales Price			
Oil ($/Bbl)	$ 76.49	$108.05	—
Natural Gas ($/Mcf)	$ 4.17	$ 4.60	—
Unit Costs			
Production ($/Boe)	$ 70.95	$ 71.89	—

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 for 2012, 2011 and 2010:

	Development Wells		Exploratory Wells	
	Productive	Dry	Productive	Dry
Turkey				
2012	14.49	1.42	4.04	7.92
2011	14.54	5.50	2.55	6.60
2010	13.75	4.20	2.50	2.50
Romania				
2012	—	—	—	—
2011	—	—	—	—
2010	—	2.00	—	1.00
Bulgaria				
2012	—	—	—	—
2011	—	—	—	—
2010	—	—	—	—

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, 2012:

	Oil		Natural Gas	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Turkey	59	55.9	199	91
Bulgaria	0	0	1	1

(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, 2012:

	Developed (Acres)	
	Gross (1)	Net (2)
Turkey	86,567	47,789

(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, 2012:

	Undeveloped (Acres)	
	Gross (1)	Net (2)
Turkey	4,272,319	3,283,974
Bulgaria	567,106	567,106
Romania (3)	988,421	494,211
Total	5,827,846	4,345,291

(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.
(3) On May 10, 2013, we notified the Romanian government that we were relinquishing our Sud Craiova license.

Undeveloped Acreage Expirations. The following table summarizes by year our undeveloped acreage scheduled to expire in the next five years:

As of December 31,	Undeveloped (Acres) [1] Gross [2]	Net [3]	% of Total Undeveloped (Acres) [1] Net [3]
2013 [4]	2,086,505	1,146,615	30.6
2014	2,213,821	2,086,290	55.7
2015	636,886	353,599	9.4
2016	325,257	162,629	4.3
2017	—	—	—

(1) Excludes the Koynare production concession that we were awarded in 2013, which expires in 2047. Also 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.
(4) Includes 494,211 net acres in Romania, which we are relinquishing.

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 2013 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. We expect the plaintiffs to appeal 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 have filed an appeal with the Court of Appeal. We will continue to vigorously defend our interests.

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.

	High	Low
2012:		
First Quarter	$1.61	$1.08
Second Quarter	$1.27	$0.86
Third Quarter	$1.14	$0.88
Fourth Quarter	$1.02	$0.70
2011:		
First Quarter	$3.49	$2.81
Second Quarter	$3.08	$1.51
Third Quarter	$1.67	$0.76
Fourth Quarter	$1.70	$0.69

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.

	High	Low
2012:		
First Quarter	$1.64	$1.10
Second Quarter	$1.29	$0.80
Third Quarter	$1.20	$0.84
Fourth Quarter	$1.06	$0.71
2011:		
First Quarter	$3.59	$2.81
Second Quarter	$3.18	$1.62
Third Quarter	$1.74	$0.75
Fourth Quarter	$1.67	$0.57

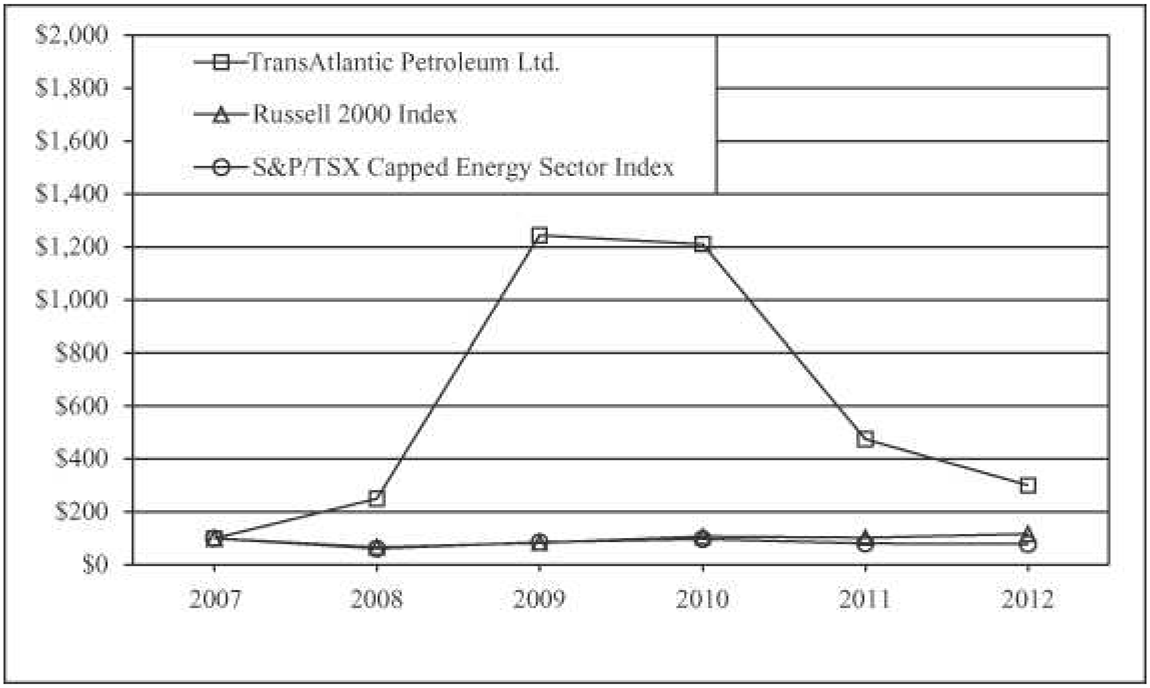
Common Shares and Dividends

As of May 1, 2013, we had 368,906,996 common shares issued and outstanding and held by 317 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.

Performance Graph

The following graph compares the cumulative total shareholder return on TransAtlantic Petroleum Ltd. common shares with the Russell 2000 Index and the S&P/TSX Capped Energy Sector Index. The graph assumes an investment of $100 on December 31, 2007 in our common shares, the Russell 2000 Index and the S&P/TSX Capped Energy Sector Index, and assumes the reinvestment of dividends where applicable. The share price performance shown on the graph below is not intended and does not necessarily indicate future price performance.



Company/Index	2007	2008	2009	2010	2011	2012
TransAtlantic Petroleum Ltd.	$100	$251	$1,244	$1,211	$476	$301
Russell 2000 Index	$100	$ 66	$ 84	$ 107	$102	$117
S&P/TSX Capped Energy Sector Index	$100	$ 61	$ 87	$ 97	$ 82	$ 78

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, 2012. 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,				
	2012	2011 (as adjusted)	2010	2009	2008
	(amounts in thousands, except per share amounts)				
Total revenues	$143,908	$ 128,905	$ 70,854	$ 27,748	$ 111
Net loss from continuing operations	(6,373)	(77,574)	(29,545)	(40,061)	(16,475)
Comprehensive income (loss)	38,470	(173,012)	(77,514)	(52,545)	(16,475)
Basic and diluted net loss per common share from continuing operations	(0.02)	(0.22)	(0.09)	(0.19)	(0.25)
Basic weighted average number of shares outstanding	367,415	355,971	312,488	212,320	66,524
Diluted weighted average number of shares outstanding	367,415	355,971	312,488	212,320	66,524

	As of December 31,				
	2012	2011 (as adjusted)	2010	2009	2008
	(amounts in thousands)				
Total assets	$358,258	$ 448,802	$473,968	$307,083	$ 81,254
Long-term liabilities	72,819	112,904	62,486	13,341	14
Shareholders’ equity	213,827	171,273	276,057	264,607	74,940
Capital expenditures, including acquisitions	81,824	152,440	170,317	92,359	10,268

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, have stable governments, are net importers of petroleum, have an existing petroleum transportation infrastructure and provide favorable commodity pricing, royalty rates and tax rates to exploration and production companies. As of December 31, 2012, we held interests in approximately 4.4 million net onshore and offshore acres of developed and undeveloped oil and natural gas properties in Turkey, Bulgaria and Romania. As of May 1, 2013, approximately 40% 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.

2012 Financial and Operational Performance

- During 2012, we derived 72.5% of our oil and natural gas sales revenues from the production of oil and 27.5% from the production of natural gas.
- Total oil and natural gas sales revenues increased to $134.1 million for 2012 from $124.2 million realized in 2011, excluding sales of purchased natural gas. The increase was primarily the result of a $6.56 per Boe increase in the average price received and a 58 Mbbl increase in oil production.
- Production increased to 949 net Mbbl of oil and decreased to 4,238 net Mmcf of natural gas for 2012, compared to 891 net Mbbl of oil and 4,657 net Mmcf of natural gas for 2011.
- In 2012, we incurred $81.8 million in capital expenditures, including acquisition costs, compared to capital expenditures of $152.4 million in 2011. The decrease is primarily due to the acquisitions of TBNG, Direct Bulgaria, Direct Petroleum Morocco, Inc. ("Direct Morocco") and Anschutz Morocco Corporation ("Anschutz") in 2011.
- During 2012, we repaid all of our short-term borrowings, compared to short-term borrowings of $80.7 million in 2011. At December 31, 2012, our debt outstanding was $32.8 million, all of which was long-term.
- Our net loss from continuing operations for 2012 was $6.4 million, resulting primarily from $40.0 million of exploration, abandonment and impairment of certain proved and unproved oil and natural gas properties.

Recent Developments

We completed the sale of our oilfield services business during 2012. For additional information on our recent developments, see "Item 1. Business—Recent Developments."

Current Operations

During 2012, we continued to develop our Selmo, Molla, and Arpatepe oil fields and our Thrace Basin natural gas properties. For additional information on our current operations, see "Item 1. Business—Current Operations."

Planned Operations

We continue to actively explore and develop our existing oil and natural gas properties in Turkey and evaluate opportunities for further activities in Bulgaria. For more information on our planned 2013 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 3—Significant accounting policies" to our consolidated financial statements included in this Annual Report on Form 10-K. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. These estimates are based on historical experience, information received from third parties, and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

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

Oil and Natural Gas Properties. In accordance with the successful efforts method of accounting for oil and natural gas properties, costs of productive wells, developmental dry holes and productive leases are capitalized into appropriate groups of properties based on geographical and geological similarities. Acquisition costs of proved properties are amortized using the unit-of-production method based on total proved reserves, and exploration well costs and additional development costs are amortized using the unit-of-production method based on proved developed reserves. Proceeds from the sale of properties are credited to property costs, and a gain or loss is recognized when a significant portion of an amortization base is sold or abandoned. Exploration costs, such as exploratory geological and geophysical costs, delay rentals and exploration overhead, are charged to expense as incurred. Exploratory drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to exploration expense if and when the well is determined to be non-productive. The determination of an exploratory well's ability to produce 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. Oil and natural gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset 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 an independent expert. 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 (iv) operations management and other factors associated with the area. Impairment is taken on the unproved property cost 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. Accordingly, transactions costs related to acquisitions are to be recorded as a reduction of earnings in the period they are incurred and costs related to issuing debt or equity securities that are related to the transaction will continue to be recognized in accordance with other applicable rules under U.S. GAAP. ASC 810-10-65 requires non-controlling interests to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for non-controlling interests and transactions with non-controlling interest holders in consolidated financial statements.

Foreign Currency Translation. 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 re-measuring transactions and monetary accounts in a currency other than the functional currency are included in earnings. For certain of our controlled entities, 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. The accounting basis of the assets and liabilities affected by the change are adjusted to reflect the difference between the exchange rate when the asset or liability arose and the exchange rate on the date of the change.

Other Recent Accounting Pronouncements and Reporting Rules

In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* ("ASU 2011-04"). ASU 2011-04 amends ASC 820, *Fair Value Measurements and Disclosures* ("ASC 820"), providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurement and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 became effective for interim and annual periods beginning after December 15, 2011. We adopted ASU 2011-04 on January 1, 2012. The adoption did not have a material effect on our financial statements.

In June 2011, FASB issued ASU 2011-05, *Presentation of Comprehensive Income* ("ASU 2011-05"). ASU 2011-05 requires the presentation of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. In December 2011, FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU 2011-05* ("ASU 2011-12"). ASU 2011-12 deferred the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income. The amendments became effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We adopted ASU 2011-05 on January 1, 2012. The adoption did not have a material effect on our financial statements.

In September 2011, FASB issued ASU 2011-08, *Testing Goodwill for Impairment* ("ASU 2011-08"). ASU 2011-08 allows both public and nonpublic entities an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity would no longer be required to calculate the fair value of a reporting unit unless the entity determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. ASU 2011-08 became effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We adopted ASU 2011-08 on January 1, 2012. The adoption did not have a material effect on our financial statements.

In December 2011, FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities* (“ASU 2011-11”). ASU 2011-11 requires entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. Application of ASU 2011-11 will be effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The adoption of ASU 2011-11 is not expected to have a material effect on our financial statements.

In July 2012, FASB issued ASU 2012-02, *Testing Indefinite-Lived Intangible Assets for Impairment* (“ASU 2012-02”). The update provides an entity with the option first to assess qualitative factors in determining whether it is more likely than not that the indefinite-lived intangible asset is impaired. After assessing the qualitative factors, if an entity determines that it is not more likely than not that the indefinite-lived intangible asset is impaired, then the entity is not required to take further action. If an entity concludes otherwise, then it is required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. Early adoption was permitted. We did not early adopt the provisions of ASU 2012-02. We do not expect the adoption of ASU 2012-02 to have a material effect on our financial statements.

In February 2013, FASB issued ASU 2013-09, *New Disclosures for Items Reclassified Out of Accumulated Other Comprehensive Income* (“ASU 2013-09”). ASU 2013-09 requires reclassification adjustments for items that are reclassified out of accumulated other comprehensive income to net income to be presented in the statements where the components of net income and the components of other comprehensive income are presented or in the footnotes to the financial statements. Additionally, the amendment requires cross-referencing to other disclosures currently required for other reclassification items. The amendments are effective for interim and annual reporting periods beginning after December 15, 2012. The adoption of ASU 2013-09 is not expected to have a material impact on our financial statements.

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 pronouncements will have a significant effect on our current or future earnings or operations.

Results of Operations—Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

	Year Ended December 31, 2012	Year Ended December 31, 2011 (as adjusted)	Change 2012-2011
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Production:			
Oil (Mbbl)	949	891	58
Natural gas (Mmcf)	4,238	4,657	(419)
Total production (Mboe)	1,655	1,667	(12)
Average sales prices:			
Oil (per Bbl)	$ 102.55	$ 100.27	$ 2.28
Natural gas (per Mcf)	$ 8.68	$ 7.05	$ 1.63
Oil equivalent (per Boe)	$ 81.04	$ 74.48	$ 6.56
Revenues:			
Oil and natural gas sales	134,113	124,162	9,951
Sale of purchased natural gas	7,882	2,668	5,214
Other	1,913	2,075	(162)
Total revenues	143,908	128,905	15,003
Costs and expenses:			
Production	17,804	18,475	(671)
Exploration, abandonment and impairment	39,993	60,952	(20,959)
Cost of purchased natural gas	7,694	2,645	5,049
Seismic and other exploration	5,040	11,542	(6,502)
Revaluation of contingent consideration	—	6,000	(6,000)
General and administrative	33,947	36,305	(2,358)
Depletion	26,024	37,004	(10,980)
Depreciation and amortization	2,191	2,004	187
Interest and other expense	8,340	13,665	(5,325)
Foreign exchange gain (loss)	1,083	(11,973)	13,056
Loss on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(3,829)	(4,854)	(1,025)
Non-cash change in fair value on commodity derivative contracts	(1,719)	(3,572)	(1,853)
Total loss on commodity derivative contracts	(5,548)	(8,426)	(2,878)
Oil and gas costs per Boe:			
Production	$ 10.76	$ 11.08	$ (0.32)
Depletion	$ 15.72	$ 22.20	$ (6.48)

Oil and Natural Gas Sales. Excluding sales of purchased natural gas, total oil and natural gas sales increased to $134.1 million in 2012, from $124.2 million in 2011. Of this increase, $10.8 million was the result of an increase in the average sales prices received and the sale of 58 additional Mbbl of oil in 2012. This increase was partially offset by a decrease of $0.9 million attributable to a decrease in our production volumes of 12 Mboe to 1,655 Mboe for 2012, compared to 1,667 Mboe in 2011. Production volumes decreased primarily on our TBNG wells due to high decline rates and less drilling activity for the year ended December 31, 2012 compared to the same period in 2011. Our average sales price received for 2012 was $81.04 per Boe, compared to $74.48 per Boe for 2011.

Production. Production expenses for 2012 decreased to $17.8 million from $18.5 million in 2011.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs decreased to $40.0 million in 2012 compared to $61.0 million for 2011. The decrease was primarily due to the impairment of our Bulgarian properties of $25.9 million in 2011 following the ban on fracture stimulation enacted by the Bulgarian Parliament in January 2012. Impairment for 2012 was taken on a portion of our proved assets in Turkey for $6.7 million and on our exploration licenses in Turkey for $8.4 million. In 2011, sixteen wells were written off to exploratory dry hole expense for $26.8 million. Additionally, we recorded impairment of approximately $18.8 million on our properties in Turkey in 2011, primarily driven by downward revisions in natural gas reserves in the Alpullu and Edirne fields. In 2012, 16 wells were written off for $22.6 million, and a partial write-off of a well was expensed for $2.1 million.

Seismic and Other Exploration. Seismic and other exploration costs decreased to $5.0 million for 2012, compared to $11.5 million for 2011. The decrease was due a reduction in the number of seismic data acquisition projects from 28 in 2011 to eleven in 2012.

Revaluation of Contingent Consideration. During 2011, we determined that there was an increase in the likelihood that we may not be able to complete one of our drilling obligations required as part of the acquisition of Direct Morocco, Anschutz and Direct Bulgaria. Therefore, we increased our costs and expenses by $6.0 million in 2011 to reflect our potential future costs. There were no contingent consideration costs required during 2012.

General and Administrative. General and administrative expense decreased $2.4 million to $33.9 million for 2012, compared to $36.3 million for 2011, primarily due to reductions in employee-related costs of $1.8 million, legal and accounting expenses of $2.0 million, acquisition costs of $1.2 million and travel costs of $0.3 million. Employee-related costs decreased due to reductions in head count. Legal and accounting expenses were higher in the comparable period in 2011 due to the late filing of our Annual Report on Form 10-K for the year ended December 31, 2010, and our quarterly Report on Form 10-Q for the three months ended March 31, 2011. We had no acquisitions during the year ended 2012, as compared to two acquisitions during the same period in 2011. This decrease was partially offset by increases of $2.0 million for a contingency related to our Aglen exploration permit in Bulgaria and $1.7 million as a result of TBNG being included for a full twelve months in 2012. The remaining decrease of $0.8 million was attributable to our overall cost reduction efforts.

Depletion . Depletion expense decreased to $26.0 million for 2012, compared to $37.0 million in 2011. The decrease was due primarily to a reduction in our depletable basis in the Alpullu and Edirne fields, which was partially offset by additions in the Molla, Goksu and Tekirdag fields. The overall decrease was partially offset by downward reserve revisions and lower sales volumes, which increased the depletion rates for certain fields.

Depreciation and Amortization. Depreciation and amortization expense increased to $2.2 million for 2012, compared to $2.0 million in 2011.

Interest and Other Expense. Interest and other expense decreased to $8.3 million for 2012, as compared to $13.7 million for 2011. The decrease was primarily due to the decrease in our outstanding debt. At December 31, 2012, our total outstanding debt was approximately $32.8 million, compared to $158.7 million at December 31, 2011.

Foreign Exchange Gain (Loss). We recorded a foreign exchange gain of $1.1 million in 2012 compared to a loss of $12.0 million in 2011. The change in foreign exchange is primarily due to the appreciation of the U.S. Dollar compared to the New Turkish Lira ("TRY") in 2012.

Loss on Commodity Derivative Contracts. During 2012, we recorded a loss on commodity derivative contracts of $5.5 million, as compared to a loss of $8.4 million for 2011. We recorded a $1.7 million unrealized loss and a $3.8 million realized loss on our commodity derivative contracts for 2012, compared to a $3.6 million unrealized loss and a $4.9 million realized loss for 2011. Unrealized gains and losses are attributable to changes in oil and natural gas prices and volumes hedged from one period end to another. We are required under our Amended and Restated Credit Facility to hedge between 30% and 75% of our anticipated production volumes in the Selmo and Arpatepe oil fields in Turkey.

Other Comprehensive Income (Loss). We record foreign currency translation adjustments from the process of translating the functional currency of the financial statements of our foreign subsidiaries into the U.S. Dollar reporting currency. Foreign currency translation adjustment for 2012 increased to a $22.2 million gain from a $52.1 million loss for 2011 due to the appreciation of the U.S. Dollar compared to the TRY.

Discontinued Operations. All revenues and expenses associated with our Moroccan operations and oilfield services business for 2012 and 2011 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, 2012	2011 (as adjusted)
	(in thousands)	
Revenues:		
Oil and natural gas sales	$ 68	$ 217
Oilfield services	19,888	28,202
Total revenues	19,956	28,419
Costs and expenses:		
Production	789	928
Exploration, abandonment and impairment	—	23,163
Seismic and other exploration	—	67
Oilfield services costs	12,955	24,157
General and administrative	10,938	10,046
Depreciation, depletion and amortization	—	11,903
Accretion	—	1
Total costs and expenses	24,682	70,265
Operating loss	(4,726)	(41,846)
Other (expense) income:		
Interest and other expense	(156)	(474)
Interest and other income	562	116
Foreign exchange (loss) gain	(763)	3,090
Total other (expense) income	(357)	2,732
Loss before income taxes from discontinued operations	(5,083)	(39,114)
Gain on disposal of discontinued operations	35,999	—
Income tax provision	(8,297)	(4,255)
Net income (loss) from discontinued operations	$ 22,619	$ (43,369)

Results of Operations—Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

	Year Ended December 31,		Change
	2011 (as adjusted)	2010	2011-2010
	(in thousands of U.S. Dollars, except per unit amounts and production volumes)		
Production:			
Oil (Mbbl)	891	690	201
Natural gas (Mmcf)	4,657	1,709	2,948
Total production (Mboe)	1,667	975	692
Average sales prices:			
Oil (per Bbl)	$ 100.27	$ 80.01	$ 20.26
Natural gas (per Mcf)	$ 7.05	$ 7.63	$ (0.58)
Oil equivalent (per Boe)	$ 74.48	$ 71.63	$ 2.85
Revenues:			
Oil and natural gas sales	124,162	69,839	54,323
Sale of purchased natural gas	2,668	—	2,668
Other	2,075	1,015	1,060
Total revenues	128,905	70,854	58,051
Costs and expenses:			
Production	18,475	20,286	(1,811)
Exploration, abandonment and impairment	60,952	12,691	48,261
Cost of purchased natural gas	2,645	—	2,645
Seismic and other exploration	11,542	16,883	(5,341)
Revaluation of contingent consideration	6,000	—	6,000
General and administrative	36,305	26,049	10,256
Depletion	37,004	12,369	24,635
Depreciation and amortization	2,004	1,629	375
Interest and other expense	13,665	7,055	6,610
Foreign exchange loss	11,973	1,872	10,101
Loss on commodity derivative contracts:			
Cash settlements on commodity derivative contracts	(4,854)	(29)	(4,825)
Non-cash change in fair value on commodity derivative contracts	(3,572)	(1,595)	(1,977)
Total loss on commodity derivative contracts	(8,426)	(1,624)	(6,802)
Oil and gas costs per Boe:			
Production	$ 11.08	$ 20.81	$ (9.73)
Depletion	$ 22.20	$ 12.69	$ 9.51

Oil and Natural Gas Sales . Excluding sales of purchased natural gas, total oil and natural gas sales increased to $124.2 million in 2011, from $69.8 million realized in 2010. Of this increase, $4.8 million was the result of an increase in the average sales prices received and $49.6 million was the result of an increase in our production volumes of 692 Mboe to 1,667 Mboe for 2011, compared to 975 Mboe in 2010. Production volumes increased primarily due to the acquisitions of Amity and Petrogas in August 2010 and TBNG in June 2011, which accounted for approximately 629 Mboe of the increase. The remaining production volume increase was primarily attributable to increased production in the Selmo and Arpatepe oil fields. Our average sales price received for 2011 was $74.48 per Boe, compared to $71.63 per Boe for 2010.

Production. Production expenses for 2011 decreased to $18.5 million from $20.3 million in 2010. The decrease in production expenses was primarily attributable to the increase in the utilization of our oilfield services business to provide these services.

Exploration, Abandonment and Impairment. Exploration, abandonment and impairment costs increased to $61.0 million in 2011, compared to $12.7 million for 2010. The increase was primarily due to the impairment of our Bulgarian properties of $25.9 million in 2011 following the ban on fracture stimulation enacted by the Bulgarian Parliament in January 2012. Additionally, we recorded impairment of approximately $18.8 million on our properties in Turkey in 2011, primarily driven by downward revisions in natural gas reserves in the Alpullu and Edirne fields. In 2011, 16 wells were written off to exploratory dry hole expense for $26.8 million.

Seismic and Other Exploration. Seismic and other exploration expense decreased to $11.5 million for 2011, compared to $16.9 million for 2010. The decrease was due primarily to our seismic programs in 2011 occurring on licenses that we jointly hold with other working interest owners who bore their proportionate share of the costs.

General and Administrative. General and administrative expense increased to $36.3 million in 2011, compared to $26.0 million in 2010, primarily due to the expansion of our operating activities during 2011, an increase in consulting and professional service fees, primarily related to the late filings of our Annual Report on Form 10-K for the year ended December 31, 2010 and our Quarterly Report on Form 10-Q for the three months ended March 31, 2011 and for the evaluation of bond financing.

Depletion. Depletion expense increased to $37.0 million for 2011, compared to $12.4 million in 2010. The increase was due primarily to increased production, as well as an increase to our depletable base, both of which were primarily the result of acquisitions in 2011. The increase was also due to downward reserve revisions which increased the depletion rate for certain fields.

Depreciation and Amortization. Depreciation and amortization expense increased to $2.0 million for 2011, compared to $1.6 million in 2010.

Interest and Other Expense. Interest and other expense increased to $13.7 million for 2011, compared to $7.1 million for 2010. The increase was primarily due to an increase in our outstanding debt. At December 31, 2011, our total outstanding debt was approximately $158.7 million, compared to $136.8 million at December 31, 2010.

Foreign Exchange Loss . We recorded a foreign exchange loss of $12.0 million in 2011 compared to a loss of $1.9 million in 2010. The increase is primarily due to the devaluation of the TRY compared to the U.S. Dollar in 2011.

Loss on Commodity Derivative Contracts . During 2011, we recorded a loss on commodity derivative contracts of $8.4 million, as compared to a loss of $1.6 million for 2010. We recorded a $3.6 million unrealized loss and a $4.9 million realized loss on our commodity derivative contracts for 2011, compared to a $1.6 million unrealized loss and a $29,000 realized loss for 2010. Unrealized gains and losses are attributable to changes in oil and natural gas prices and volumes hedged from one period end to another. We are required under our Amended and Restated Credit Facility to hedge a portion of our oil production in the Selmo and Arpatepe oil fields in Turkey.

Other Comprehensive Income (Loss). We record foreign currency translation adjustments from the process of translating the functional currency of the financial statements of our foreign subsidiaries into the U.S. Dollar reporting currency. Foreign currency translation adjustment for 2011 increased to a $52.1 million loss from a $7.8 million loss for 2010 due to the devaluation of the TRY compared to the U.S. Dollar in 2011.

Discontinued Operations. All revenues and expenses associated with our Moroccan operations and oilfield services business for 2011 and 2010 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,	
	2011 (as adjusted)	2010
	(in thousands)	
Revenues:		
Oil and natural gas sales	$ 217	$ —
Oilfield services	28,202	14,709
Total revenues	28,419	14,709
Costs and expenses:		
Production	928	—
Exploration, abandonment and impairment	23,163	19,924
Seismic and other exploration	67	195
Oilfield services costs	24,157	18,899
General and administrative	10,046	3,681
Depreciation, depletion and amortization	11,903	12,463
Accretion	1	—
Total costs and expenses	70,265	55,162
Operating loss	(41,846)	(40,453)
Other (expense) income:		
Interest and other expense	(474)	(1,786)
Interest and other income	116	86
Foreign exchange gain	3,090	2,683
Total other income	2,732	983
Loss before income taxes from discontinued operations	(39,114)	(39,470)
Income tax provision	(4,255)	(731)
Net loss from discontinued operations	$ (43,369)	$(40,201)

Capital Expenditures

For 2012, we incurred $81.8 million in capital expenditures, including acquisition costs, compared to capital expenditures of $152.4 million for 2011. The decrease in capital expenditures was primarily due to the acquisitions of TBNG, Direct Bulgaria, Direct Morocco and Anschutz in 2011. In 2013, we expect our capital expenditures will be approximately $131.0 million. We expect capital expenditures during 2013 to consist of approximately $101.0 million of drilling and completion expense (over 60 gross wells), $19.0 million of seismic expense and $11.0 million on infrastructure and other expense. Approximately 32% of these anticipated expenditures is expected to be directed to the Thrace Basin in Turkey, devoted to developing conventional and unconventional natural gas production, building infrastructure and acquiring seismic data. Most of the remaining 68% of these anticipated expenditures is expected to be directed to southeastern Turkey, devoted to drilling developmental and exploratory oil wells at Selmo, Arpatepe, Gaziantep and Molla. We expect cash on hand, borrowings from our Amended and Restated Credit Facility and cash flow from operations to be sufficient to fund our capital expenditures. If not, we will either curtail our discretionary capital expenditures or seek other funding sources. If we successfully complete a joint venture transaction during 2013, we anticipate increasing our drilling activity. Our projected 2013 capital expenditure budget is subject to change.

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Liquidity and Capital Resources

Our primary sources of liquidity for 2012 were our cash and cash equivalents, borrowings under our Amended and Restated Credit Facility and proceeds from the sale of our oilfield services business. At December 31, 2012, we had cash and cash equivalents of $14.8 million, $32.8 million in long-term debt and working capital of $8.6 million (excluding assets and liabilities held for sale), compared to cash and cash equivalents of $15.1 million, $80.7 million in short-term debt, $78.0 million in long-term debt and a working capital deficit of $65.7 million at December 31, 2011 (excluding assets and liabilities held for sale). Cash provided by operating activities from continuing operations during 2012 was $52.0 million, as compared to cash provided by operating activities from continuing operations of $51.0 million in 2011. The decrease was primarily due to the timing of collecting our accounts receivable and paying our accounts payable.

As of December 31, 2012, the outstanding principal amount of our debt was $32.8 million. In addition to cash, cash equivalents and cash flow from operations, at December 31, 2012, we had an Amended and Restated Credit Facility, which is discussed below.

Amended and Restated Credit Facility . DMLP, TEMI, Talon Exploration, TransAtlantic Turkey, Amity and Petrogas are Borrowers under the Amended and Restated Credit Facility. Each of the Borrowers is our wholly owned subsidiary. The Amended and Restated Credit Facility is guaranteed by TransAtlantic Petroleum Ltd. and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide.

The amount drawn under the Amended and Restated Credit Facility may not exceed the lesser of (i) $250.0 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. At December 31, 2012, the lenders had aggregate commitments of $78.0 million, with individual commitments of $39.0 million each. On the last day of each fiscal quarter commencing December 31, 2013 and at the maturity date, the lenders’ commitments are subject to reduction according to the following schedule:

End of Period	Commitment Amount
December 2013	$67,500,000
March 2014	$60,000,000
June 2014	$52,000,000
September 2014	$45,000,000
December 2014	$37,500,000
March 2015	$30,000,000
June 2015	$22,500,000
September 2015	$15,000,000
December 2015	$ 7,500,000
March 2016	$ 0

The borrowing base was re-determined semi-annually on April 1st and October 1st of each year prior to September 30, 2012, and is now re-determined quarterly on January 1st, April 1st, July 1st and October 1st of each year. Following our semi-annual borrowing base redetermination on October 1, 2012, our borrowing base at December 31, 2012 was $59.7 million. Following our semi-annual borrowing base redetermination on April 1, 2013, our borrowing base is currently $56.9 million. 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;
- the debt value which results in the loan life coverage ratio for such calculation date being 1.30 to 1.00; and
- the debt value which results in a debt service coverage ratio for any calculation period being 1.25 to 1.00.

The Amended and Restated Credit Facility matures on the earlier of (i) May 18, 2016, or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual report of Standard Bank 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 report prepared by Standard Bank and the Borrowers. The Amended and Restated 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 Amended and Restated Credit Facility accrue interest at a rate of three-month LIBOR plus 5.50% per annum. The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.20% 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 Amended and Restated Credit Facility, and (b) 1.10% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Amended and Restated 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 Standard Bank or (b) 5.50% for all other letters of credit.

The Amended and Restated 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 Amended and Restated Credit Facility, including maintaining the following financial ratios during the four most recently completed fiscal quarters occurring on or after March 31, 2011:

- 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 Amended and Restated 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 Amended and Restated 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) 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), (vii) transaction costs, expenses and fees incurred in connection with the negotiation, execution and delivery of the Amended and Restated Credit Facility and the related loan documents, and (vii) any other non-cash charges (including dry hole expenses and seismic expenses, to the extent such expenses would be capitalized), 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 Amended and Restated Credit Facility, until amounts under the Amended and Restated 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 or (xiv) open or maintain new deposit, securities or commodity accounts.

An event of default under the Amended and Restated 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 Amended and Restated 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.

Under the terms of the Amended and Restated Credit Facility, we are required to provide our audited consolidated financial statements for the year ended December 31, 2012 to the lenders by March 31, 2013, and we are required to provide the Borrowers' unaudited financial statements of for the year ended December 31, 2012 to the lenders by April 30, 2013. We have obtained waivers from Standard Bank and BNP Paribas that extend those deadlines to May 15, 2013 and June 30, 2013, respectively.

At December 31, 2012, the Borrowers had borrowed $32.8 million under the Amended and Restated Credit Facility, had availability of $26.9 million under the Amended and Restated Credit Facility and were in compliance with all material covenants under the Amended and Restated Credit Facility. Pursuant to the Amended and Restated Credit Facility, TEMI entered into costless derivative contracts and three-way collar contracts with Standard Bank and BNP Paribas, which hedge the price of oil during 2013, 2014 and 2015. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk." If our borrowing base is increased in the future, we would be required under the Amended and Restated Credit Facility to hedge additional volumes of oil.

Contractual Obligations

The following table presents a summary of our contractual obligations at December 31, 2012:

	Payments Due By Year (in thousands)						
	Total	2013	2014	2015	2016	2017	Thereafter
Debt	$32,766	$ —	$ —	$ —	$32,766	$ —	$ —
Leases and other	9,370	3,315	1,415	1,415	436	—	2,789
Total	$42,136	$3,315	$1,415	$1,415	$33,202	$ —	$ 2,789

Off-Balance Sheet Arrangements

We did not have any off-balance sheet arrangements at December 31, 2012.

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, 2012, our exposure to interest rate changes related primarily to floating rate borrowings under our Amended and Restated Credit Facility. At December 31, 2012, we had $32.8 million in outstanding borrowings under the Amended and Restated Credit Facility. The interest we pay on borrowings under the Amended and Restated Credit Facility is equal to three-month LIBOR plus 5.50% per annum (5.76% at December 31, 2012). A hypothetical 10% change in the interest rates we pay on the Amended and Restated Credit Facility as of December 31, 2012 would result in an increase or decrease in our interest costs of approximately $0.2 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 corporate entities in Turkey, Bulgaria and Romania is the local currency. The functional currency for TransAtlantic Petroleum Ltd. is the U.S. Dollar. As a result, translation adjustments will result from the process of translating the functional currency of our subsidiary financial statements into the U.S. Dollar reporting currency. Our currency exposures primarily relate to the TRY, as our largest subsidiaries measure their assets, liabilities and results of operations using the TRY. Such 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) as foreign currency translation adjustments. As of December 31, 2012 and December 31, 2011, we had losses of $28.0 million and $50.2 million, respectively, in accumulated other comprehensive loss as a result of translation adjustments. For the years ended December 31, 2012 and 2011, we recorded a gain of $22.2 million and a loss of $52.1 million, respectively, of foreign currency translation adjustments.

We are also subject to foreign currency exposures as a result of our operations in the other foreign countries in which we operate and foreign currency fluctuations as oil prices received are referenced in U.S. Dollar-denominated prices. 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. As of December 31, 2012, we had 20.4 million TRY (approximately $11.5 million) in cash and cash equivalents that are remeasured into our functional currency using the period-end exchange rate, with such re-measurement gains or losses recorded in foreign exchange (gain) loss. For 2012 and 2011, we recorded a foreign exchange gain of $1.1 million and a foreign exchange loss of $12.0 million, respectively. We estimate that a 10% change in the exchange rates would impact such cash balances and our net loss by approximately $1.0 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 Amended and Restated Credit Facility, at least one of the Borrowers is required to maintain commodity derivative contracts with Standard Bank and BNP Paribas. As a result, TEMI has entered into costless collar and three-way collar derivative contracts with Standard Bank and BNP Paribas to hedge the price of oil. Pursuant to our Amended and Restated 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. Our commodity derivative contracts are carried at their fair value in earnings as they occur. We recognize unrealized and realized 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.” Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows. 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 the year ended December 31, 2012, we recorded a net unrealized loss on commodity derivative contracts of $1.7 million. We recorded a net unrealized loss on commodity derivative contracts of $3.6 million in 2011.

The following tables summarize our outstanding commodity derivatives contracts with respect to our future oil production as of December 31, 2012:

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, 2013—December 31, 2013	775	$ 82.26	$ 121.36	$ (253)
Collar	January 1, 2014—December 31, 2014	622	$ 80.83	$ 118.07	(292)
					$ (545)

		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 Liability (in thousands)
Three-way collar contract	January 1, 2013—December 31, 2013	831	$ 85.00	$ 97.13	$ 162.13	$ (3,655)
Three-way collar contract	January 1, 2014—December 31, 2014	726	$ 85.00	$ 97.13	$ 162.13	(2,150)
Three-way collar contract	January 1, 2015—December 31, 2015	1,016	$ 85.00	$ 91.88	$ 151.88	(2,440)
						$ (8,245)

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

The Company's audit committee engaged KPMG LLP, a Delaware limited liability partnership ("KPMG LLP"), as the Company's independent registered public accounting firm and dismissed KPMG LLP, a Canadian limited liability partnership ("KPMG Canada"), as the Company's independent registered public accounting firm, effective upon the completion of the audit of the Company's financial statements as of and for the year ended December 31, 2011, which occurred on March 23, 2012.

During the years ended December 31, 2009, 2010 and 2011 and for the period January 1, 2012 through March 23, 2012, there were no disagreements (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) between the Company and KPMG Canada on any matter of accounting principles or practices, financial statement disclosure or audit scope or procedure, which disagreements if not resolved to the satisfaction of KPMG Canada, would have caused KPMG Canada to make reference to the subject matter of the disagreements in its reports with respect to the Company's consolidated financial statements for such periods.

During the years ended December 31, 2009, 2010 and 2011 and for the period January 1, 2012 through March 23, 2012, there were no reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K), except that the Company did not maintain effective internal control over financial reporting because of the effect of material weaknesses on the achievement of the objectives of the control criteria as described below.

During the years ended December 31, 2009, 2010 and 2011 and for the period January 1, 2012 through March 23, 2012, neither the Company nor anyone on its behalf has consulted with KPMG LLP with respect to either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on the Company's consolidated financial statements, and neither a written report nor oral advice was provided to the Company that KPMG LLP concluded was an important factor considered by the Company in reaching a decision as to any accounting, audit or financial reporting issue; or (ii) any matter that was either the subject of a disagreement (as defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K) or a reportable event (as defined in Item 304(a)(1)(v) of Regulation S-K).

The reports of KPMG Canada on the Company's consolidated financial statements for the years ended December 31, 2009, 2010 and 2011 did not contain an adverse opinion or a disclaimer of an opinion, and were not qualified or modified as to uncertainty, audit scope or accounting principles, except that:

- KPMG Canada's report as of December 31, 2009 indicated that the Company did not maintain effective internal control over financial reporting because of the effect of the following material weaknesses on the achievement of the objectives of the control criteria: (i) the Company did not maintain adequate controls to facilitate the flow of information used in financial reporting throughout the organization; (ii) the Company did not maintain an effective period-end financial statement closing process; (iii) the Company did not design procedures to ensure detailed reviews and verifications of inputs related to the analysis of accounts or transactions and schedules supporting financial statement amounts and disclosures; and (iv) the Company did not maintain effective monitoring controls over foreign operations in Istanbul, Turkey;
- KPMG Canada's report as of December 31, 2010 contained an explanatory paragraph stating that the Company had suffered recurring losses from operations, had a working capital deficiency and significant commitments, which raised substantial doubt about the Company's ability to continue as a going concern and indicated that the Company did not maintain effective internal control over financial reporting because of the effect of the following material weaknesses on the achievement of the objectives of the control criteria: (i) the Company did not maintain an effective control environment; (ii) the Company did not maintain a sufficient complement of personnel with an appropriate level of accounting knowledge, experience, and training in the application of U.S. generally accepted accounting principles and in internal control over financial reporting commensurate with its financial reporting requirements and business environment; (iii) the Company did not maintain an effective anti-fraud program designed to detect and prevent fraud relating to an ongoing program to manage identified fraud risks; (iv) the Company did not design and maintain effective controls for the review, supervision and monitoring of its accounting operations throughout the organization and for monitoring and evaluating the adequacy of its internal control over financial reporting; (v) the Company did not maintain effective controls over the preparation, review and approval of all financial statement account reconciliations; (vi) the Company did not maintain effective controls over the recording and monitoring of intercompany accounts; (vii) the Company did not maintain effective controls over the re-measurement and translation of its foreign entity account balances; (viii) the Company did not maintain effective controls over the review, approval, documentation and recording of its journal entries; (ix) the Company did not maintain adequate controls to integrate the accounting functions of its foreign entities; (x) the Company did not maintain effective controls over its information technology general controls; and (xi) the Company did not maintain an effective period-end financial statement closing process; and
- KPMG Canada's report as of December 31, 2011 contained an explanatory paragraph stating that the Company had suffered recurring losses from operations and had a working capital deficiency, which raised substantial doubt about the Company's ability to continue as a going concern and indicated that the Company did not maintain effective internal control over financial reporting because of material weaknesses relating to the Company not maintaining an effective period end financial statement closing process and effective controls over translations of the Company's foreign entity account balances that were identified and included in management's assessment.

The Company provided KPMG LLP and KPMG Canada with a copy of the above disclosures. Neither KPMG LLP nor KPMG Canada expressed any disagreement with the above disclosures.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

As of December 31, 2012, 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, and as a result of the material weaknesses in internal control over financial reporting described below, our chief executive officer and chief financial officer concluded that, as of December 31, 2012, our disclosure controls and procedures were not 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.

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* 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 not effective as of December 31, 2012 because of the identification of the material weaknesses identified below.

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement in our annual or interim financial statements will not be prevented or detected on a timely basis. We have identified the material weaknesses described below:

1) We have not maintained a sufficient complement of qualified personnel with U.S. GAAP knowledge in our Addison, Texas and Istanbul, Turkey offices, the effect of which resulted in the ineffective design or operation of our internal controls over significant account balances and estimates. Specifically:

    - Significant agreements were not subject to review by adequately trained technical resources resulting in accounting for such agreements to not be in accordance with U.S. GAAP.

- Our income tax provision and significant non-routine transactions were not subjected to review by personnel with adequate experience and the requisite level of technical expertise.
- Controls over the completeness and accuracy of period-end accruals and contingencies were not operated by personnel with the requisite skills and did not capture accounting transactions in a timely manner.

2) Our management review and approval controls were not complete and comprehensive and, in many instances, were not operating at a sufficient level of precision, to prevent or detect material misstatements in our financial statements. Specifically:

- Reconciliations of key account balances including oil and natural gas properties (including depletable bases, impairment, and abandonment), income taxes, revenue, accruals and contingencies were not performed on a timely basis or at a level of precision sufficient to detect a misstatement in the related accounts.
- Management approval controls over routine and non-routine transactions such as invoice review and approval, payment processing and journal entry reviews were ineffective to ensure that these transactions had been properly approved, reviewed and reported in the consolidated financial statements.
- Management did not maintain effective controls over provisioning and removal of access to programs and data, including segregation of duties, within critical accounting systems.

As a result of these two material weaknesses, which are pervasive in nature, we recorded material adjustments to revenue, oil and natural gas properties, accumulated depletion, depletion expense, impairment expense, current and long-term deferred income tax assets and liabilities, deferred income tax expense, foreign exchange loss, foreign currency translation, and gain (loss) from discontinued operations in our preliminary consolidated financial statements for the year ended December 31, 2012. In addition, adjustments were made to other account balances in our preliminary consolidated financial statements for the year ended December 31, 2012 and there is a reasonable possibility that a material misstatement of our financial statements will not be prevented or detected on a timely basis.

3) We have not designed and implemented effective internal controls around the accounting for oil and natural gas properties. Specifically:

- Controls over capitalization of expenditures to oil and natural gas properties (i.e., designation of costs as development, exploratory, or maintenance) were not designed and implemented effectively.
- Controls over the completeness and accuracy of our reconciliations of proved and unproved properties schedules to our general ledger and depletable bases, including significant inputs used in calculating depletion, were not designed and implemented effectively.
- Management's controls over the evaluation of long-lived assets for impairment were not effectively designed and documented.

As a result of this material weakness, management recorded material adjustments to oil and natural gas properties, accumulated depletion, depletion expense, and impairment expense (including the related tax effects) in our preliminary consolidated financial statements for the year ended December 31, 2012.

4) We have not designed and implemented effective internal controls over income tax provisions. Specifically, we outsource the preparation of the income tax provision, but lack reconciliation and management review controls that operate at a sufficient level of precision to ensure the completeness and accuracy of the data used in the computation of deferred taxes.

As a result of this material weakness, management recorded material adjustments to current and long-term deferred income tax assets and liabilities and deferred income tax expense accounts in our preliminary consolidated financial statements for the year ended December 31, 2012.

5) We have not designed and implemented effective internal controls over significant non-routine transactions. Specifically, internal controls over the proper identification of assets sold and liabilities transferred in connection with the divestiture of our oilfield services business were not sufficient to ensure the completeness and accuracy of the accounting for the assets disposed of through the sale.

As a result of this material weakness, management recorded material adjustments to loss from discontinued operations and gain on disposal of discontinued operations, including the related income tax effects, in our preliminary consolidated financial statements for the year ended December 31, 2012.

6) We have not designed and implemented effective internal controls over remeasurement and translation of our foreign subsidiaries' account balances. Specifically, controls over remeasurement and translation of U.S. Dollar-denominated commodity derivative contracts held by a Turkish subsidiary with New Turkish Lira as its functional currency, were ineffective.

As a result of this material weakness, management recorded material adjustments to foreign exchange gain (loss) and foreign currency translation adjustment balances in our preliminary consolidated financial statements for the year ended December 31, 2012.

The effectiveness of our internal control over financial reporting as of December 31, 2012 has been audited by KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements, as stated in their report on pages F-3 and F-4 of our consolidated financial statements.

Management's Plan for Remediation of Our Material Weaknesses

Many of the underlying causes of these material weaknesses existed prior to 2012. The current management team has worked diligently to improve the design and operating effectiveness of internal control over financial reporting. While improvements occurred throughout 2012, many of the improvements were implemented in the later part of 2012, and thus were not in place during the entire year. The evaluation of the control improvements needed to remediate material weaknesses did not take place with sufficient time to remediate identified weaknesses. Management expects remediation efforts in 2013 to continue to improve our internal control over financial reporting.

During March and April 2013, management conducted a thorough review and analysis of its accounting for oil and natural gas properties. The financial impacts of this review and analysis are described in Note 2 of our consolidated financial statements. In addition, we hired a consulting firm to assist management in its review of our accounts and financial statements. Specifically, the consulting firm reviewed the areas of income tax accounting, share based compensation accounting and oil and natural gas properties accounting. The financial impact of this review and analysis is described in Note 2 of our consolidated financial statements. The consulting firm will continue to assist management in reviews of these areas and will also assist management in developing and implementing adequate review procedures and checklists across all accounting areas.

In April 2013, we hired a vice president of accounting and corporate controller with twelve years of "Big 4" public accounting experience, including several years of public company oil and natural gas accounting experience, to manage the accounting function beginning in May 2013.

Management's plan to strengthen our internal control over financial reporting by December 31, 2013 focuses on addressing and remediating the identified deficiencies in our processes which contributed to the material weaknesses. In addition, we plan to perform control testing earlier in the year to permit time to remediate some or all identified deficiencies prior to December 31, 2013.

Specifically during 2013, we plan to hire additional personnel sufficiently knowledgeable of, and experienced in, U.S. accounting procedures and practices and with sufficient technical U.S. GAAP accounting expertise (including successful efforts accounting for oil and natural gas and deferred taxes), continue training our Turkish accounting and finance personnel on U.S. accounting practices and procedures and on U.S. GAAP. We plan to shift management of certain accounting functions performed in Turkey directly to U.S.-based personnel sufficiently knowledgeable of, and trained in, U.S. accounting practices and procedures and in U.S. GAAP. We will also evaluate the feasibility of moving certain accounting processes from our Istanbul, Turkey office to our Addison, Texas office. We will work to develop and implement more robust and comprehensive review procedures and checklists. We will continue to reduce our chart of accounts, automate and streamline accounting processes where possible, improve documentation and training and continue to monitor the performance of control activities in both our Istanbul, Turkey and Addison, Texas offices. Finally, we expect to complete the design phase of new accounting software that will automate many of the manual calculations and tasks we currently perform in our financial closing process and that will include additional controls which will be built into the software. We anticipate completing the implementation of the new accounting software by the end of 2014.

In addition, our chief executive officer and chief financial officer will regularly meet with our senior accounting staff to monitor progress, identify continuing deficiencies and make any necessary adjustments to personnel or our plan to ensure the effective implementation of remedial measures.

While we believe that the above remediation plan will result in the remediation of our material weaknesses in 2013, there is no assurance that these efforts will be sufficient and that additional remedial efforts will not be necessary.

Changes in Internal Control Over Financial Reporting

The following change in our internal control over financial reporting occurred during the fourth quarter of 2012 and has affected, or is reasonably likely to materially affect, our internal control over financial reporting.

- We hired a property accountant with public company, international oil and natural gas exploration accounting experience who began in January 2013.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Directors

Set forth below is a brief biography of each of the current members of our board of directors.

N. Malone Mitchell, 3 rd (Age 51) has served as our chief executive officer since May 2011, as a director since April 2008 and as the Company's 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.

Through his senior executive officer positions at Riata Corporate Group, LLC and Riata Energy, Inc., Mr. Mitchell brings extensive executive leadership experience, organizational experience and over 27 years of experience in the oil and natural gas industry to the board of directors. Mr. Mitchell is familiar with the Company's day-to-day operations and performance and the oil and natural gas industry in general. Mr. Mitchell's insight into the Company's operations and performance is critical to board discussions.

Bob G. Alexander (Age 79) has served as a director since 2010. Mr. Alexander, a founder of Alexander Energy Corporation, served as chairman of the board, president and chief executive officer of Alexander Energy Corporation from 1980 to 1996. Alexander Energy Corporation merged with National Energy Group, Inc. in 1996, and Mr. Alexander served as president and chief executive officer of National Energy Group, Inc., an oil and natural gas property management company, from 1998 to 2011. From 1976 to 1980, Mr. Alexander served as vice president and general manager of the northern division of Reserve Oil, Inc. and president of Basin Drilling Corporation, both subsidiaries of Reserve Oil and Gas Company of Denver, Colorado. Mr. Alexander also served on the board of Quest Resource Corporation from June to August 2008.

Mr. Alexander has extensive experience as an executive officer in the oil and natural gas services industry and has extensive financial, executive leadership and organizational experience. Mr. Alexander also has experience serving as a director of other public companies, which brings important insights into board oversight and corporate governance matters.

Brian E. Bayley (Age 60) has served as a director since 2001. From June 2003 to present, Mr. Bayley has served as a director, and from September 2010 to present has served as a resource lending advisor, of Sprott Resource Lending Corp. (formerly, Quest Capital Corp.), a publicly traded natural resource lending corporation listed on the Toronto Stock Exchange and NYSE MKT. From May 2009 until September 2010, Mr. Bayley has also served as president and chief executive officer of Sprott Resource Lending Corp. From January 2008 until May 2009, Mr. Bayley served as co-chairman of Sprott Resource Lending Corp., and from June 2003 until January 2008 and during March 2008, Mr. Bayley served as president and chief executive officer, respectively. Since December 1996, he has also served as the president and a director of Ionic Management Corp., a private management company.

Mr. Bayley is a former chief executive officer that has extensive executive leadership and organizational experience in the financial industry. Mr. Bayley's experience makes him an effective member of the Company's corporate governance committee and an effective chairman of the Company's compensation committee. Mr. Bayley also has significant experience serving as a director of other public companies, which brings important insights into board oversight, compensation and corporate governance matters.

Charles J. Campise (Age 62) has served as a director since June 2012. He retired from Toreador Resources Corporation, an oil exploration and production company, in March 2010, where he had served as senior vice president and chief financial officer since May 2006. Mr. Campise served as corporate controller for Transmeridian Exploration Incorporated from December 2003 until May 2005. Prior to that, Mr. Campise served in a variety of financial and accounting positions at Sovereign Oil & Gas Company, Apache Corporation and Ocean Energy, Inc.

Mr. Campise is a former chief financial officer who brings more than 40 years of international oil and natural gas financial and accounting expertise to our board. Mr. Campise is an audit committee financial expert and chairman of the Company's audit committee as a result of his 28 years of experience as a certified public accountant and more than 40 years of experience in various accounting and financial roles at oil and natural gas exploration and production companies. Mr. Campise also has experience serving as a director of other public companies, which brings important insights into board oversight, audit and corporate governance matters.

Mel G. Riggs (Age 58) has served as a director since 2009. Mr. Riggs has served as executive vice president and chief operating officer since December 2010, and as a director since 1994, of Clayton Williams Energy, Inc., a public exploration and production company that develops and produces oil and natural gas. From 1991 to December 2010, Mr. Riggs served as senior vice president—finance, secretary, treasurer, and chief financial officer of Clayton Williams Energy, Inc.

Mr. Riggs has a strong operational background as an executive officer and has extensive financial, executive leadership and organizational experience. Mr. Riggs is an audit committee financial expert and chairman of the Company's audit committee as a result of his 34 years of experience as a certified public accountant and 20 years of experience as a chief financial officer. Mr. Riggs also has significant experience serving as a director of another public company, which brings important insights into board oversight and corporate governance matters.

Michael D. Winn (Age 51) has served as a director since 2004. Mr. Winn is the president of Seabord Capital Corp., a private consulting company that provides investment analysis and financial services to companies operating in the oil and natural gas, mining and energy sectors, since he formed that company in 2013. From 1997 through 2012, Mr. Winn was the president of Terrasearch Inc., a private consulting company that provides analysis on mining and energy companies. Prior to that, Mr. Winn spent four years as an analyst for a Southern California-based brokerage firm where he was responsible for the evaluation of emerging oil, natural gas and mining companies. Mr. Winn has worked in the oil and natural gas industry since 1983 and the mining industry since 1992.

Mr. Winn has a strong operational background as a consultant and executive officer and has extensive consulting experience, focusing on the oil and natural gas industry, as well as executive leadership and organizational experience. Mr. Winn also has significant experience serving as a director of other public companies, which brings important insights into board oversight, compensation and corporate governance matters.

Executive Officers

Name	Age	Positions
N. Malone Mitchell, 3 rd	51	Chairman of the Board of Directors and Chief Executive Officer
Ian J. Delahunty	33	President
Wil F. Saqueton	43	Vice President and Chief Financial Officer
Jeffrey S. Mecom	47	Vice President, Legal and Corporate Secretary

Set forth below is a brief biography of each of our current executive officers. Information relating to Mr. Mitchell is set forth above under "Directors."

Ian J. Delahunty has served as our president since January 2013. Mr. Delahunty served as our vice president, business development from February 2012 until his promotion to president. He joined us in October 2008 and has worked with our operations in Turkey, Romania and Morocco, serving as our vice president, engineering overseeing completions and workovers from November 2009 to January 2012. Prior to joining us, he worked as a senior engineer with Schlumberger N.V. in Vietnam and the United States and as completions engineer with Occidental Petroleum Corp. in the United States.

Wil F. Saqueton has served as our vice president and chief financial officer since August 2011. Mr. Saqueton previously served as our corporate controller from May 2011 until August 2011 and as our consultant from February 2011 until May 2011. Prior to joining us, 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.

Jeffrey S. Mecom has served as our corporate secretary since May 2006 and as a vice president since May 2007. Before joining us in April 2006, Mr. Mecom was an attorney in private practice in Dallas. Mr. Mecom served as vice president, legal and corporate secretary with Aleris International, Inc., a former NYSE-listed international metals recycling and processing company, from 1995 until April 2005.

To the best of our knowledge, there are no arrangements or understandings between any officer and any other person, pursuant to which any person referred to above was selected as an officer.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, executive officers, and any persons who own more than 10% of a registered class of our equity securities, to file reports of ownership and changes in ownership with the SEC. SEC regulations require executive officers, directors and greater than 10% shareholders to furnish us with copies of all Section 16(a) forms they file. Based solely on its review of the copies of such forms furnished or available to us, we believe that our directors, executive officers and 10% shareholders complied with all Section 16(a) filing requirements for the year ended December 31, 2012 except as follows: one late Form 4 was filed by Mr. Mecom on June 14, 2012 to report the grant of restricted stock units on May 14, 2012; one late Form 4 was filed by Mr. Saqueton on August 8, 2012 to report the vesting of restricted stock units on August 4, 2012; one late Form 4 was filed by Mr. Saqueton on June 14, 2012 to report the grant of restricted stock units on May 14, 2012; one late Form 4 was filed by Mr. Saqueton on February 15, 2012 to report the grant of restricted stock units on January 5, 2012; one late Form 4 was filed by Mr. Yavuz on June 18, 2012 to report the purchase of our common shares, par value $0.01 (the “Common Shares”) on June 13, 2012; and one late Form 4 was filed by Mr. Yavuz on June 14, 2012 to report the grant of restricted stock units on May 14, 2012.

Item 11. Executive Compensation

Compensation Discussion and Analysis

This section contains a discussion of the material elements of the Company’s executive compensation program for 2012 for: (i) its chief executive officer as of December 31, 2012, N. Malone Mitchell, 3rd, (ii) its chief financial officer as of December 31, 2012, Wil F. Saqueton, and (iii) its three other most highly compensated executive officers as of December 31, 2012, Ian J. Delahunty, Mustafa Yavuz and Chad W. Potter (collectively, the “named executive officers”).

Executive Summary

The Company's pay for performance philosophy emphasizes long-term, non-cash incentive compensation over short-term, cash incentive compensation for its named executive officers. Mr. Mitchell serves as chairman of the board and has also served as the Company's chief executive officer since May 2011. Mr. Mitchell received non-employee director compensation for his 2012 service as chairman and has elected not to receive additional compensation for his services as chief executive officer. As a result, the following references to named executive officers in this Compensation Discussion and Analysis do not include Mr. Mitchell.

In 2012, Messrs. Saqueton, Delahunty and Potter received 2012 year-end cash bonuses, consistent with the Company's practice of paying cash bonuses to all U.S. resident employees of the Company in an amount equal to two weeks of annual base salary multiplied by 10% for each year of employment with the Company. In addition, Mr. Saqueton was awarded a cash bonus of $15,000 for his role in the preparation of the Company's quarterly financial reports and the sale of the Company's oilfield services business, and Mr. Potter was awarded a cash bonus of $85,000 pursuant to his offer letter of employment.

On May 1, May 14 and December 14, 2012, the named executive officers also received grants of restricted stock units relating to performance in the first half of 2011, the second half of 2011 and the first half of 2012, respectively. The grants, which were awarded to all eligible employees under the Company's long-term incentive policy, were in an amount equal to 25% of each named executive officer's base salary for each semi-annual performance period, except for the May 14 and December 14 grants to (i) Mr. Saqueton, which, in the aggregate, were equal to approximately 100% of his base salary, (ii) Mr. Yavuz, which, in the aggregate, were equal to approximately 100% of his base salary and (iii) Mr. Potter, which, in the aggregate, were equal to 35% of his base salary pursuant to his offer letter for employment with the Company. For 2012, the compensation committee did not make any discretionary equity grants to the named executive officers.

Pursuant to Mr. Saqueton's appointment as vice president and chief financial officer, Mr. Potter's offer letter for employment with the Company and Mr. Yavuz's appointment as chief operating officer, Messrs. Saqueton, Potter and Yavuz were granted 136,691, 175,439 and 149,125 restricted stock units, respectively, on January 5, 2012. Mr. Saqueton's restricted stock units vested one-third on August 4, 2012 and will vest one-third on each of August 4, 2013 and 2014. Mr. Potter's restricted stock units vested one-third on September 1, 2012, and the remainder vested upon his resignation on May 10, 2013. Mr. Yavuz's restricted stock units vested one-third on January 5, 2013, and the remainder were forfeited upon his resignation as chief operating officer in January 2013.

Executive Compensation Philosophy

The Company's executive compensation program is designed to attract, motivate and retain talented executives. The Company's pay for performance philosophy focuses executives' efforts on achieving strategic corporate goals without encouraging excessive risk taking. At this stage of the Company's development, executive compensation is not tied to specific financial performance metrics, but the compensation committee focuses on the contributions of the executives to the Company's strategy and may take into consideration the Company's overall financial performance. The compensation committee, which consists entirely of independent board members, controls the executive compensation program for the named executive officers, as well as for the Company's other officers and employees. The Company's executive compensation objectives are to:

- pay for performance without excessive risk;
- attract, retain and motivate superior executives;
- pay competitive levels of salary and total compensation; and
- align the interests of management with the interests of the Company's shareholders.

Process of Determining Compensation

The Company's compensation committee determines executive compensation. The Company's chairman and other members of its board may also participate in compensation committee meetings to provide their evaluation of the performance of the Company's executive officers and their contributions to the Company's business strategy, and the Company's chief executive officer provides compensation recommendations as to executive officers other than himself. Management plays a significant role in this process, through evaluating employee performance, recommending salary levels, discretionary cash bonuses and restricted stock unit awards and preparing meeting information for use in compensation committee meetings. Although the compensation committee has not retained a compensation consultant, it may do so in the future.

Shareholder Say-on-Pay Votes

Following the Company's 2012 Annual Meeting of Shareholders, the compensation committee also considered the advisory vote of the Company's shareholders on executive compensation when reviewing its compensation decisions and policies. Of those shareholders voting, on an advisory basis, for or against the proposal, approximately 95% voted to approve the Company's executive compensation. The compensation committee believes this affirms shareholders' support of its approach to executive compensation and did not change its approach in 2012. The compensation committee will continue to consider the outcome of the Company's say-on-pay votes when making future compensation decisions for the named executive officers.

Elements of Executive Compensation

The 2012 executive compensation program consisted of base salary, a cash incentive bonus award, and restricted stock units. Executives also received standard employee benefits. There is no formal policy regarding the allocation between short-term or long-term incentive compensation or between cash and non-cash incentive compensation for the Company's executive officers. The compensation committee relies on each committee member's knowledge and experience as well as information provided by management when determining the appropriate level and mix of compensation. In general, the compensation committee believes that long-term, non-cash incentive compensation should be emphasized over short-term, cash incentive compensation for the Company's executive officers. The Company has not adopted formal share ownership guidelines for its named executive officers, but the Company believes that named executive officers owning shares helps align their interests with those of long-term shareholders. As of April 30, 2013, Mr. Mitchell beneficially owned approximately 40% of the Company's Common Shares.

Base Salaries . The Company's compensation committee reviews and sets base salaries annually. When determining base salary levels for the named executive officers, the compensation committee reviews their performance and contribution to the achievement of corporate objectives. The compensation committee does not retain a compensation consultant nor prepare a benchmarking report in connection with base salary determinations. Rather, the compensation committee relies on its experience to set base salaries in line with what it believes is competitive for similarly situated executives in the industry. Mr. Mitchell has elected to not receive compensation for his services as chief executive officer of the Company.

Effective February 1, 2012, Mr. Delahunty was appointed as vice president, business development of the Company at an annual base salary of $225,000.

Mr. Yavuz was president of Thrace Basin Natural Gas (Turkiye) Corporation, which the Company acquired in June 2011. Effective January 5, 2012, Mr. Yavuz was appointed as chief operating officer of the Company, and the compensation committee set his annual net base salary at 400,000 New Turkish Lira (approximately $230,000), which was grossed up for Turkish tax purposes to a total of 636,000 New Turkish Lira (approximately $355,000).

The compensation committee did not change the base salaries for Messrs. Saqueton or Potter in 2012.

Short-Term Incentive Compensation . In addition to base salaries, the Company awards cash bonuses on a discretionary basis to its employees, including the named executive officers. For the named executive officers other than the Company's chief executive officer, the compensation committee, in consultation with the Company's chief executive officer, recommends cash bonuses for the board's approval. The compensation committee normally reviews the performance of the Company's chief executive officer and recommends the bonus for the Company's chief executive officer to the board of directors. In 2012, the compensation committee did not review Mr. Mitchell's performance, as he elected not to receive compensation for his services as chief executive officer.

While the Company does not have a formal cash incentive bonus plan, it has historically paid year-end cash bonuses to all of its employees resident in the United States, as well as its named executive officers who are resident in the United States, in December of each year in an amount equal to approximately two weeks of annual base salary multiplied by 10% for each year of employment with the Company. In 2012, consistent with this practice, Messrs. Delahunty, Saqueton and Potter were awarded 2012 year-end cash bonuses of $16,115, $14,769 and $8,462, respectively.

The compensation committee may also award discretionary cash bonuses based on the officer's performance, the officer's general contributions to achieving corporate goals and the Company's achievement of goals set by the board of directors. The compensation committee does not assign any specific weights to these measures or use a formula to determine bonus amounts. Mr. Saqueton was awarded a discretionary cash bonus of $15,000 for his role in the preparation of the Company's quarterly financial reports and the sale of the Company's oilfield services business in 2012. Mr. Potter was awarded a cash bonus of $85,000 in 2012 pursuant to his offer letter for employment. Each of these bonuses was paid in 2012. The compensation committee did not award any other discretionary cash bonuses for 2012 to any of the named executive officers because the Company was not profitable in 2012.

Long-Term Incentive Compensation . The Company's board of directors designed its long-term incentive plan to ensure that incentive compensation rewards the Company's employees' contributions to the long-term positive performance of the Company and is intended to align the Company's executives' interests with its shareholders' interests. The long-term incentive policy is also designed to attract and retain qualified professionals throughout the Company and to attract and retain skilled, dedicated employees who are willing to commit to a long term of foreign service, while being able to pay modest salaries and create a meaningful ownership stake in the Company. The long-term incentive policy awards the Company's executives restricted stock units that provide them with an opportunity to earn the Company's Common Shares. The compensation committee believes this structure provides greater balance and stability to the Company's long-term incentives for executives. It also provides a form of long-term compensation that aids retention, encourages long-term value creation and aligns financial interests with shareholders without encouraging excessive risk taking.

Long-term incentive awards are granted by the board of directors, in the case of non-employee directors, and by the compensation committee on the recommendation of the chief executive officer, in the case of named executive officers, including the president and chief financial officer. The Company's current long-term incentive policy provides for a semi-annual grant of restricted stock units to all eligible employees, including the named executive officers, equal to 25% of base salary for each of the first and last six months of service during the year. The semi-annual grants vest in three equal annual installments on January 15, in the case of grants relating to the last six months of the year, and on July 15, in the case of grants relating to the first six months of the year. The compensation committee also has the authority to approve discretionary grants to the named executive officers to award performance and ensure that the number of awards granted to any particular individual is commensurate with the individual's level of ongoing responsibility within the Company. Long-term incentive awards are also generally awarded to key employees by the compensation committee upon the commencement of employment with the Company based on the level of responsibility of the employee.

On May 1, 2012, May 14, 2012 and December 14, 2012, all of the named executive officers received grants of restricted stock units, which were made to all eligible employees of the Company. The May 1 and May 14, 2012 semi-annual restricted stock unit grants relate to performance in the first and second halves of 2011, respectively, and the December 14, 2012 semi-annual restricted stock unit grants relate to performance in the first half of 2012. The compensation committee kept the percentage equal to 25% of each named executive officer's base salary for each semi-annual performance period, except for (i) the May 14 and December 14 grants to Messrs. Saqueton and Yavuz which, in the aggregate, were equal to approximately 100% of their base salaries pursuant to their appointment as executive officers, and (ii) the May 14 and December 14 grants to Mr. Potter, which, in the aggregate, were equal to approximately 35% of his base salary pursuant to his offer letter for employment with the Company. Mr. Yavuz's semi-annual restricted stock unit grants were calculated using his net annual salary, before gross-up for taxes, and converted from TRY to U.S. Dollars. The compensation committee reviews this policy annually, and may also grant additional discretionary awards for exceptional service or as signing bonuses. The compensation committee reviewed this policy in 2012, did not make any changes to this policy and did not grant additional discretionary awards for exceptional service in 2012. The restricted stock units awarded to the Company's named executive officers generally vest in three annual installments and are subject to the continued employment of the named executive officer through each such restricted period.

Pursuant to Mr. Saqueton's appointment as vice president and chief financial officer, Mr. Potter's offer letter for employment with the Company, and Mr. Yavuz's appointment as chief operating officer, Messrs. Saqueton, Potter and Yavuz were granted 136,691, 175,439 and 149,125 restricted stock units, respectively, on January 5, 2012. Mr. Saqueton's restricted stock units vested one-third on August 4, 2012 and will vest one-third on each of August 4, 2013 and 2014. Mr. Potter's restricted stock units vested one-third on September 1, 2012, and the remainder vested upon his resignation on May 10, 2013. Mr. Yavuz's restricted stock units vested one-third on January 5, 2013, and the remainder were forfeited upon his resignation as chief operating officer in January 2013.

Employee Benefits

The Company offers core employee benefits coverage in order to provide its global workforce with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction through programs that focus on work/life balance. The benefits available are substantially the same for all U.S. employees and include medical and dental coverage. In addition, the Company offers a 401(k) plan, which provides a reasonable level of retirement income reflecting employees' careers with the Company. U.S. employees are eligible to participate in these plans.

Compensation Committee Interlocks and Insider Participation

The compensation committee is comprised of Messrs. Alexander, Bayley and Riggs. During the year ended December 31, 2012, no member of the compensation committee was or had been an officer or employee of the Company or any of its subsidiaries or had any relationship requiring disclosure pursuant to Item 404 of Regulation S-K. None of the Company's executive officers served as a director or member of the compensation committee (or other board committee performing similar functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on the Company's compensation committee or as one of its directors.

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Compensation Committee Report on Executive Compensation

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

The foregoing report is provided by the following directors, who constitute the compensation committee.

COMPENSATION COMMITTEE

Bob G. Alexander
Brian E. Bayley, Chairman
Mel Riggs

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Executive Compensation

Fiscal Year 2012, 2011 and 2010 Summary Compensation Table

The following Fiscal Year 2012, 2011 and 2010 Summary Compensation Table contains information regarding compensation for 2012, 2011 and 2010 that the Company paid to its named executive officers. Riata Management, LLC ("Riata") pays a portion of the salary, cash bonus and benefits earned by the named executive officer pursuant to that certain service agreement, as amended (the "Service Agreement"), effective May 1, 2009, with Longfellow, Viking Drilling LLC ("Viking Drilling"), MedOil Supply, LLC and Riata. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Certain Relationships and Related Transactions—Service Agreement" below for additional information. Mr. Mitchell and his wife own 100% of Riata.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)(3)	Total ($)
N. Malone Mitchell, 3 rd(4)	2012	31,250	0	0	2,358,000	2,389,250
Chairman of the Board and Chief Executive Officer	2011	25,000	0	23,508	13,196,000	13,244,508
Ian J. Delahunty (5)	2012	225,000	16,115	42,664	43,768	327,547
President						
Wil F. Saqueton (6)	2012	240,000	29,769	392,382	13,258	675,409
Vice President and Chief Financial Officer	2011	129,692	29,230	22,864	4,358	186,144
Mustafa Yavuz (7)	2012	355,000	0	397,666	0	752,666
Former Chief Operating Officer						
Chad W. Potter (8)	2012	200,000	93,462	319,865	8,425	621,752
Former Vice President, Financial and Investor Relations						

(1) Amounts shown do not reflect compensation actually received by the named executive officers. Rather, the amounts represent the aggregate grant date fair value of restricted stock units computed in accordance with Accounting Standards Codification ("ASC") 718, *Compensation—Stock Compensation* ("ASC 718"). A discussion of the calculation of the aggregate grant date fair value of restricted stock units is set forth under Note 12, Shareholders' equity, under the heading "Restricted stock units" in the notes to the consolidated financial statements.

(2) For the named executive officers other than Mr. Mitchell, these amounts consist of Company-paid portions of insurance premiums, Company contributions to a 401(k) savings plan and Company-paid international travel incentives. For Mr. Delahunty, this amount also includes $35,160 that was reimbursed to Mr. Delahunty for the payment of his 2011 Turkish income taxes.

(3) For Mr. Mitchell, the amounts shown consist of approximately $2.4 million in 2012 and $13.2 million in 2011 reimbursed to Riata pursuant to the Service Agreement, which includes payments to Riata for salaries and benefits for employees of Riata who provided technical and administrative services to the Company under the Service Agreement, other than the Company's named executive officers, and an allocation of Riata's overhead to the Company. Such amounts do not reflect actual payments made to Mr. Mitchell for his services as an employee or a director. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Certain Relationships and Related Transactions—Service Agreement" below for a description of the material terms of the Service Agreement.

(4) The amounts shown under the heading "Salary" reflect non-employee director compensation paid to Mr. Mitchell for his service as chairman of the board. Mr. Mitchell was appointed chief executive officer in May 2011 and has elected not to receive additional compensation for his service as chief executive officer.

(5) Mr. Delahunty became an executive officer in June 2012.

(6) Mr. Saqueton became our vice president and chief financial officer in August 2011.

(7) Mr. Yavuz became our chief operating officer in January 2012 and resigned from the Company in January 2013.

(8) Mr. Potter became an executive officer in June 2012 and resigned from the Company in May 2013.

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Fiscal Year 2012 Grants of Plan-Based Awards Table

The table below lists each grant of a plan-based award to the Company's named executive officers during 2012.

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#)(1)	Grant Date Fair Value of Stock Awards ($)
N. Malone Mitchell, 3 rd(2)			
Ian Delahunty			
	5/1/12	7,216	8,515
	5/14/12	16,703	15,534
	12/14/12	22,428	18,615
Wil F. Saqueton		136,691	
	1/5/12		200,936
	5/1/12	2,417	2,852
	5/14/12	98,883	91,961
	12/14/12	116,426	96,633
Mustafa Yavuz		149,125	
	1/5/12		219,214
	5/14/12	93,639	87,084
	12/14/12	110,082	91,368
Chad W. Potter		175,439	
	1/5/12		257,895
	5/14/12	36,329	33,785
	12/14/12	33,958	28,185

(1) These are restricted stock units awarded pursuant to the Incentive Plan.
(2) Mr. Mitchell did not receive any restricted stock unit awards in 2012.

Discussion Regarding Fiscal Year 2012, 2011 and 2010 Summary Compensation Table and Fiscal Year 2012 Grants of Plan-Based Awards Table

Indemnification Agreements

The Company has indemnification agreements with each of its directors and executive officers. These agreements, among other things, require the Company to indemnify each director and executive officer to the fullest extent permitted by the Bermuda *Companies Act 1981* or other applicable law, against any and all expenses of a proceeding, in the event that such person was, is or becomes a party to or witness or other participant in such proceeding by reason of such person's service as a member of the Company's board of directors or as an executive officer.

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Fiscal Year 2012 Outstanding Equity Awards At Fiscal Year-End Table

The following table lists all of the outstanding stock options and stock awards held on December 31, 2012 by each of the Company's named executive officers. The table also includes the value of the stock awards based on the closing price of the Company's Common Shares on the NYSE MKT on December 31, 2012, which was $0.83 per share.

Name	Grant Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)
N. Malone Mitchell, 3 rd	—		
Wil F. Saqueton	8/4/11(1)	14,245	11,823
	1/5/12(2)	91,127	75,635
	5/1/12(3)	1,611	1,337
	5/14/12(4)	98,883	82,073
	12/14/12(5)	116,426	96,634
Ian J. Delahunty	2/24/10(6)	1,652	1,371
	9/7/10(7)	1,846	1,532
	5/1/12(3)	7,216	5,989
	5/14/12(4)	16,703	13,863
	12/14/12(5)	22,428	18,615
Chad W. Potter	1/5/12(8)	116,959	97,076
	5/14/12(9)	36,329	30,153
	12/14/12(10)	33,958	28,185
Mustafa Yavuz	1/5/12(11)	149,125	123,774
	5/14/12(12)	93,639	77,720
	12/14/12(13)	110,082	91,368

(1) Vests one-half on each of May 13, 2013 and 2014.
(2) Vests one-half on each of August 4, 2013 and 2014.
(3) Vests one-half on each of July 15, 2013 and 2014.
(4) Vested one-third on January 15, 2013, and vests one-third on each of January 15, 2014 and 2015.
(5) Vests one-third on each of July 15, 2013, 2014 and 2015.
(6) Vested on January 15, 2013.
(7) Vests on July 15, 2013.
(8) Vested in full on May 10, 2013.
(9) Vested one-third on January 15, 2013, and the remainder were forfeited on May 10, 2013.
(10) Vested one-third on May 10, 2013, and the remainder were forfeited on May 10, 2013.
(11) Vested one-third on January 5, 2013, and the remainder were forfeited on January 31, 2013.
(12) Vested one-third on January 15, 2013, and the remainder were forfeited on January 31, 2013.
(13) Forfeited on January 31, 2013.

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Fiscal Year 2012 Option Exercises and Stock Vested Table

The following table summarizes stock option exercises and vesting of stock awards for each named executive officer during 2012.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)(1)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)(2)
N. Malone Mitchell, 3 rd	0	0	7,643(3)	10,075
Ian Delahunty	0	0	33,123(4)	41,754
Wil F. Saqueton	0	0	53,493(5)	49,634
Mustafa Yavuz	0	0	0	0
Chad Potter	0	0	58,480(6)	60,819

(1) Amounts shown reflect the difference between the closing price of the Company's Common Shares on the NYSE MKT on the date of exercise and the exercise price of the stock options, multiplied by the number of shares shown in the column entitled "Number of Shares Acquired on Exercise."

(2) Amounts shown reflect the value of vested restricted stock units calculated by multiplying the gross number of vested restricted stock units shown in the column "Number of Shares Acquired on Vesting" by the closing price of the Company's Common Shares on the NYSE MKT on the date of vesting.

(3) Represents the vesting of 7,643 restricted stock units on January 15, 2012.

(4) Represents the vesting of the following restricted stock units: (i) 24,659 restricted stock units on January 15, 2012, and (ii) 8,464 restricted stock units on July 15, 2012.

(5) Represents the vesting of the following restricted stock units: (i) 7,123 restricted stock units on May 13, 2012, (ii) 806 restricted stock units on July 15, 2012, and (iii) 45,564 restricted stock units on August 4, 2012.

(6) Represents the vesting of 58,480 restricted stock units on September 1, 2012.

Director Compensation

Fiscal Year 2012 Director Compensation Table

The following table provides information regarding director compensation during 2012. Mr. Mitchell serves as chairman of the board and was also appointed the Company's chief executive officer in May 2011. Mr. Mitchell received non-employee director compensation for his 2012 service as chairman and has elected not to receive additional compensation for his services as chief executive officer. This compensation is reported in the Fiscal Year 2012, 2011 and 2010 Summary Compensation Table.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)(2)(3)	Total ($)
Bob G. Alexander	$ 46,250	31,956	78,206
Brian E. Bayley	$ 47,250	31,956	79,206
Charles J. Campise (4)	$ 31,250	0	31,250
Mel G. Riggs	$ 50,000	31,956	81,956
Michael D. Winn	$ 42,250	31,956	74,206

(1) Amounts shown do not reflect compensation actually received by the directors. Rather, the amounts represent the aggregate grant date fair value of restricted stock units computed in accordance with ASC 718. A discussion of the calculation of the aggregate grant date fair value of restricted stock units is set forth under Note 12, Shareholders' equity, under the heading "Restricted stock units" in the notes to the consolidated financial statements.

(2) The amounts in this column reflect a grant of restricted stock units on January 5, 2012, which vested in full on January 5, 2013.

(3) The chart below shows the aggregate number of unvested outstanding stock awards held by each non-employee director as of December 31, 2012.

Director	Number of Common Shares Subject to Stock Awards
Alexander	21,739
Bayley	21,739
Campise	0
Riggs	21,739
Winn	21,739

(4) Mr. Campise joined the board in June 2012.

Elements of Director Compensation

Effective July 1, 2012, all non-employee directors, including the chairman, receive a fee of $75,000 each year, consisting of $18,750 in cash paid in each of June and December, and $37,500 of which is paid in the form of restricted stock units issued under the TransAtlantic Petroleum Corp. 2009 Long-Term Incentive Plan (the "Incentive Plan"). The chairman of the Company's audit committee receives an additional annual fee of $25,000 in cash. In May 2011, the board of directors formed a special committee comprised of independent directors to evaluate strategic alternatives related to the Company's oilfield services business. Messrs. Alexander, Bayley and Winn, members of the special committee, each received fees of $1,000 in cash for each meeting of the special committee that they attended in 2012. Non-employee directors do not receive extra compensation for serving on the audit, compensation or corporate governance committees of the board or for serving as chairman of the compensation committee or corporate governance committee. Non-employee directors are reimbursed for travel and other expenses directly associated with Company business.

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

Equity Compensation Plan Information

The following table sets forth the number of Common Shares to be issued upon the vesting of restricted stock units and the exercise of outstanding options issued pursuant to the Incentive Plan and the Amended and Restated Stock Option Plan (2006) (the "Option Plan," and together with the Incentive Plan, the "Plans"), the weighted average exercise price of such outstanding options and the number of Common Shares remaining available for future issuance under the Plans, at December 31, 2012.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights(1) (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a)) (c)
Equity compensation plans approved by security holders	3,302,848	$ 1.25	33,572,011(2)
Equity compensation plans not approved by security holders	—	—	—
Total	3,302,848	$ 1.25	33,572,011

(1) The weighted average exercise price does not take into account the shares issuable upon vesting of outstanding awards of restricted stock units, which have no exercise price.

(2) Pursuant to the Incentive Plan, the maximum aggregate number of Common Shares reserved for issuance under both Plans may not exceed 10% of Common Shares outstanding from time to time. As of

December 31, 2012, there were 368,748,592 Common Shares outstanding. The number of Common Shares issuable pursuant to the Incentive Plan automatically increases as the number of issued and outstanding Common Shares increases. As of April 30, 2013, there were 368,906,996 Common Shares outstanding, 155,000 Common Shares (approximately 0.04% of the outstanding Common Shares) to be issued upon exercise of outstanding options under the Option Plan and 2,426,845 Common Shares (approximately 0.7% of the outstanding Common Shares) underlying restricted stock units awarded pursuant to the Incentive Plan. As of April 30, 2013, there were 34,308,854 Common Shares remaining available for future issuances under the Incentive Plan.

Securities Owned by Directors and Executive Officers of TransAtlantic

The Company's only outstanding class of equity securities is its Common Shares. The following table sets forth information known to the Company about the beneficial ownership of its Common Shares on April 30, 2013 by (i) each current director; (ii) each named executive officer; and (iii) all of the Company's executive officers and directors as of April 30, 2013 as a group.

Unless otherwise indicated in the footnotes, each person or entity listed in the following table has sole voting power and investment power over the Common Shares listed as beneficially owned by that person or entity. Percentages of beneficial ownership are based on 368,906,996 Common Shares outstanding on April 30, 2013. Unless otherwise indicated in the footnotes, the address for each listed person is TransAtlantic Petroleum Ltd., c/o TransAtlantic Petroleum (USA) Corp., 16803 Dallas Parkway, Addison, TX 75001.

	Shares Beneficially Owned(1)	
Name of Beneficial Owner	**Number**	**Percent**
N. Malone Mitchell, 3rd	153,579,158(2)	40.8%
Ian J. Delahunty	202,671	*
Wil F. Saqueton	85,907(3)	*
Mustafa Yavuz	150,922	*
Chad W. Potter	55,079	*
Bob G. Alexander	40,202(4)	*
Brian E. Bayley	344,625	*
Charles J. Campise	5,000	*
Mel G. Riggs	96,823	*
Michael D. Winn	634,625(5)	*
All executive officers and directors as a group (11 persons)	155,514,388(6)	41.3%

* Less than 1% of the outstanding Common Shares.

(1) Beneficial ownership as reported in the table has been determined in accordance with Rule 13d-3 under the Exchange Act and is not necessarily indicative of beneficial ownership for any other purpose, including under Canadian securities laws. The number of Common Shares shown as beneficially owned includes Common Shares which for Canadian securities law purposes may not be beneficially owned but over which a person would be deemed to exercise control or direction. The number of Common Shares shown as beneficially owned includes Common Shares subject to options, common share purchase warrants, and restricted stock units ("RSUs") that are currently exercisable (in the case of options or common share purchase warrants) or that will become exercisable or vested within 60 days of April 30, 2013. RSUs that will vest within 60 days, and Common Shares subject to options or common share purchase warrants exercisable within 60 days, after April 30, 2013 are deemed outstanding for computing the percentage of the person or entity holding such securities but are not deemed outstanding for computing the percentage of any other person or entity.

(2) Based on Amendment No. 9 to Schedule 13D filed on March 23, 2012 and on Form 4 filed on December 31, 2012. According to the Amendment No. 9 to Schedule 13D, Dalea Partners, LP ("Dalea") shares voting and dispositive power over 111,040,349 Common Shares, Dalea Management, LLC ("Dalea Management")

shares voting and dispositive power over 111,040,349 Common Shares, Longfellow Energy, LP ("Longfellow") shares voting and dispositive power over 39,583,333 Common Shares, Deut 8, LLC ("Deut 8") shares voting and dispositive power over 39,583,333 Common Shares, ANBE Holdings, LP ("ANBE Holdings") shares voting and dispositive power over 39,583,333 Common Shares, ANBE LLC ("ANBE Holdings GP") shares voting and dispositive power over 39,583,333 Common Shares and Mr. Mitchell has sole voting and dispositive power over 86,220 Common Shares and shared voting and dispositive power over 152,486,191 Common Shares. Also includes 7,300,000 common share purchase warrants that are held by Dalea. Mr. Mitchell and his wife indirectly own 100% of Dalea. Dalea Management is the general partner of Dalea and is owned 100% by Mr. Mitchell and his wife. Mr. Mitchell is a partner of Dalea and a manager of Dalea Management. Deut 8 is the general partner of Longfellow and is owned 100% by Mr. Mitchell and his wife. Mr. Mitchell is a manager of Deut 8. Mr. Mitchell, his wife and children indirectly own 100% of Longfellow and ANBE Holdings. Mr. Mitchell and his wife own 100% of ANBE Holdings GP. Mr. Mitchell is the Company's current chairman and chief executive officer. Dalea, Mr. Mitchell and his wife pledged 29,000,000 Common Shares as security under a master credit agreement with Amarillo National Bank.

(3) Includes 7,122 Common Shares subject to restricted stock units that vest on May 13, 2013.

(4) Includes 11,000 Common Shares owned by Mr. Alexander's wife.

(5) Includes 180,000 Common Shares held by MDW & Associates LLC. Mr. Winn is the manager of MDW & Associates LLC.

(6) Reflects the information in footnotes (1) through (5) above.

Securities Owned by Certain Beneficial Owners

The following table sets forth information known to the Company about the beneficial ownership of its Common Shares as of April 30, 2013, by each person and entity known to the Company to own beneficially more than 5% of its outstanding Common Shares based on reports they file with the SEC. Unless otherwise indicated in the footnotes, each person or entity listed in the following table has sole voting power and investment power over the Common Shares listed as beneficially owned by that person or entity. Percentages of beneficial ownership are based on 368,906,996 Common Shares outstanding on April 30, 2013.

Dalea Partners, LP 16803 Dallas Parkway Suite 300 Addison, TX 75001	111,040,349[(1)]	29.5%
Longfellow Energy, LP 16803 Dallas Parkway Suite 300 Addison, TX 75001	39,583,333[(2)]	10.7%
Schroder Investment Management North America Ltd. 31 Gresham Street, 1st Floor London EC2V 7QA United Kingdom	32,950,575[(3)]	8.9%

(1) Based on Amendment No. 9 to Schedule 13D filed on March 23, 2012. According to the Amendment No. 9 to Schedule 13D, Dalea shares voting and dispositive power over 111,040,349 Common Shares. Includes 7,300,000 common share purchase warrants. Mr. Mitchell and his wife indirectly own 100% of Dalea. Dalea Management is the general partner of Dalea. Mr. Mitchell is a partner of Dalea and a manager of Dalea Management. Mr. Mitchell is the Company's current chairman and chief executive officer.

(2) Based on Amendment No. 9 to Schedule 13D filed on March 23, 2012. According to the Amendment No. 9 to Schedule 13D, Longfellow shares voting and dispositive power over 39,583,333 Common Shares. Deut 8 is the general partner of Longfellow and is owned 100% by Mr. Mitchell and his wife. Mr. Mitchell is a manager of Deut 8. Mr. Mitchell, his wife and children indirectly own 100% of Longfellow. Mr. Mitchell is the Company's current chairman and chief executive officer.

(3) Based on Amendment No. 1 to Schedule 13G filed on February 13, 2013. According to the Amendment No. 1, Schroder Investment Management North America Ltd. has sole voting power over 32,950,575 Common Shares and shared dispositive power over 32,950,575 Common Shares.

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

Director Independence

The standards relied upon by the board of directors in affirmatively determining whether a director is "independent" are those set forth in the rules of the NYSE MKT Company Guide and National Instrument 52-110 of the Canadian Securities Regulators ("NI 52-110"), which generally provide that independent directors are persons other than the Company's executive officers or employees. In addition, the following persons are not considered independent:

- a director who is, or during the past three years was, employed by the Company, other than prior employment as an interim executive officer (provided the interim employment did not last longer than one year);
- a director who accepted or has an immediate family member who accepted any compensation from the Company in excess of $120,000 (Cdn $75,000 under NI-52-110) during any period of twelve consecutive months within the three years preceding the determination of independence, other than compensation for board or board committee service, compensation paid to an immediate family member who is an employee (other than an executive officer) of the Company, compensation received for former service as an interim executive officer (provided the interim employment did not last longer than one year), or benefits under a tax-qualified retirement plan, or non-discretionary compensation;
- a director who is an immediate family member of an individual who is, or at any time during the past three years was, employed by the Company as an executive officer;
- a director who is, or has an immediate family member who is, a partner in, or a controlling shareholder or an executive officer of, any organization to which the Company made, or from which the Company received, payments (other than those arising solely from investments in the Company's securities or payments under non-discretionary charitable contribution matching programs) that exceed 5% of the organization's consolidated gross revenues for that year, or $200,000, whichever is more, in any of the most recent three fiscal years;
- a director who is, or has an immediate family member who is, employed as an executive officer of another entity where at any time during the most recent three fiscal years any of the issuer's executive officers served on the compensation committee of such other entity; or
- a director who is, or has an immediate family member who is, a current partner of the Company's outside independent registered public accounting firm, or was a partner or employee of the Company's outside independent registered public accounting firm who worked on the Company's audit at any time during any of the past three years.

The NYSE MKT rules provide that members of the audit committee must also comply with the independence standards under Rule 10A-3 of the Exchange Act, which provide that a member of an audit committee of a company, other than an investment company, may not, other than in his or her capacity as a member of the audit committee, the board of directors, or any other board committee: (i) accept directly or indirectly any consulting, advisory, or other compensatory fee from the Company or any subsidiary thereof, provided that, unless the rules of the national securities exchange or national securities association provide otherwise, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company (provided that such compensation is not contingent in any way on continued service); or (ii) be an affiliated person of the Company or any subsidiary thereof. NI 52-110 provides substantially similar independence standards for audit committee members.

In accordance with the NYSE MKT and NI 52-110 independence definitions, the board of directors also makes an affirmative determination that each potential independent director does not have any relationship that, in the board's opinion, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

The board of directors, in applying the above-referenced standards, has affirmatively determined that at least 50% of its members are "independent" within the meaning of the NYSE MKT rules and NI 52-110. Specifically, the board of directors has determined that each of Messrs. Alexander, Bayley, Campise, Riggs and Winn are "independent" under these rules. In addition, the board has affirmatively determined that each of Messrs. Campise, Riggs and Winn, who comprise the Company's audit committee, meet the additional independence requirements applicable to audit committee members under the NYSE MKT rules and Rule 10A-3 under the Exchange Act. As part of the board's process in making these determinations, each of these directors provided written assurances that (i) all of the above-cited objective criteria for independence were satisfied and (ii) he had no other "material relationship" with the Company that could interfere with his ability to exercise independent judgment.

Certain Relationships and Related Transactions

During 2012, the Company had various related-party transactions with its chairman and chief executive officer, Mr. Mitchell, and various companies formed and owned or controlled by Mr. Mitchell that are primarily focused on investing in energy opportunities. The various companies that Mr. Mitchell owns or controls and his relationship with the companies, as well as a description of the material terms of the transactions are included below.

- Mr. Mitchell and his wife own 100% of Riata.
    - Riata owns 100% of MedOil Supply, LLC.
- Mr. Mitchell and his wife indirectly own 100% of Dalea.
    - Dalea owns 85% of Viking Drilling.
- Mr. Mitchell, his wife and children indirectly own 100% of Longfellow.
- Mr. Mitchell and his children own 97.5% of Gundem Turizm Yatirim ve Isletme A.S. ("Gundem").
- Mr. Mitchell and trusts established for the benefit of his children own 100% of MAANBE LLC.
- Mr. Mitchell indirectly owns 50% of Maritas A.S. ("Maritas").
- Mr. Mitchell owns 50% of Viking Services Management, Ltd. ("Viking Management").
- Mr. Mitchell indirectly owns 50% of Viking Petrol Sahasi Hizmetleri A.S. ("VOS").
- Mr. Mitchell indirectly owns 50% of Viking International Limited ("Viking International").
- Mr. Mitchell indirectly owns 50% of Viking Geophysical Services, Ltd. ("Viking Geophysical").

Service Agreement

The Company is a party to the Service Agreement with Longfellow, Viking Drilling, MedOil Supply, LLC and Riata (collectively, the "Service Entities"), under which the Company and the Service Entities agreed to provide technical and administrative services to each other from time to time on an as-needed basis. Under the terms of the Service Agreement, the Service Entities agreed to provide the Company upon its request certain computer services, payroll and benefits services, insurance administration services and entertainment services, and the Company and the Service Entities agreed to provide to each other certain management consulting services, oil and natural gas services and general accounting services (collectively, the "Services"). Under the terms of the Service Agreement, the Company pays, or is paid, for the actual cost of the Services rendered plus the actual cost of reasonable expenses on a monthly basis. The Company or the Service Entities may terminate the Service Agreement at any time by providing advance notice of termination to the other party.

Pursuant to the Service Agreement, a portion of the salary, cash bonus and benefits earned by each of the Company's named executive officers is paid by Riata, and the Company reimburses Riata for the actual cost thereof. In 2012, the Company reimbursed Riata $35,000 for a portion of the salary, cash bonus and benefits provided to the named executive officers. In addition, Barbara Pope, sister-in-law of Mr. Mitchell, is an employee of Riata and provides services to the Company under the Service Agreement. In 2012, the Company reimbursed Riata $76,000 for services provided by Ms. Pope pursuant to the Service Agreement.

For 2012, the Company recorded expenditures of $2.4 million for goods and Services provided by the Service Entities pursuant to the Service Agreement or other arrangements described below, including salary, bonus and benefits reimbursements identified in the prior paragraph, of which $0.2 million was payable at December 31, 2012. Payables in the amount of $0.2 million due under the Service Agreement at December 31, 2012 were settled in cash during the first quarter of 2013. There were no amounts due to the Company from the Service Entities at December 31, 2012.

The following table provides a breakdown of reimbursements of actual costs and expenses made by the Company during 2012 to the Service Entities under the Service Agreement:

Service Agreement Category	For the Year Ended December 31, 2012 (in thousands)
Salaries and benefits for named executive officers	$ 35
Salaries and benefits for employees, other than named executive officers	1,575
Oilfield services	107
Office and field expenses and supplies	65
Allocated overhead	405
Rent	0
Other	171
Total	$ 2,358

Aircraft Reimbursements

In addition, the Company and Riata have an arrangement whereby the Company's executive officers, employees, or consultants, or other persons providing Services to the Company under the Service Agreement, are permitted to use aircraft owned by Riata for Company-related business travel. For the use of this aircraft, the Company reimburses Riata an amount per passenger equal to the cost of a business class ticket on a commercial airline for comparable travel. Riata bears 100% of the cost of fuel, landing fees and all other expenses incurred in connection with such flights in excess of the amount reimbursed by the Company. In each case, the actual cost of the flight exceeded the amount of the reimbursement by the Company. For 2012, the Company reimbursed Riata $27,000 for the use of this aircraft. Because this reimbursement is only for Company-related business travel of persons providing Services to the Company and is integrally and directly related to the performance of such persons' duties, the Company's reimbursement is not compensation nor a perquisite to any of its directors or executive officers.

Other Transactions with Mr. Mitchell

On June 1, 2010, Viking International entered into a lease agreement under which it leased space for storage, maintenance, and staging of material and equipment for oilfield services and services related to oil and natural gas drilling, exploration, development, geological or geophysical activities or oilfield infrastructure at premises owned by Gundem. Under the lease agreement, Viking International paid Gundem the New Turkish

Lira equivalent of $25,000 per month from July 2010 through December 2011, and $26,000 per month from January 2012 through June 2012, In 2012, Viking International paid approximately $0.1 million to Gundem under this lease agreement.

On June 28, 2010, the Company's wholly-owned subsidiary, TransAtlantic Worldwide, Ltd. ("TransAtlantic Worldwide") entered into a credit agreement with Dalea for the purpose of funding the acquisition of all the shares of Amity and Petrogas and for general corporate purposes. The amounts due under the credit agreement, which was amended on May 13, 2011, November 7, 2011 and March 15, 2012, accrued interest at a rate of three-month LIBOR plus 5.5% per annum. In addition, interest on the credit agreement ceased to accrue from April 1, 2012 until the closing of the sale of the Company's oilfield services business. TransAtlantic Worldwide borrowed an aggregate of $73.0 million under the credit agreement and used the proceeds to finance a portion of the purchase price of the shares of Amity and Petrogas. On September 1, 2010, the Company issued 7,300,000 common share purchase warrants to Dalea pursuant to the credit agreement. The common share purchase warrants are exercisable until September 1, 2013 and have an exercise price of $6.00 per share. TransAtlantic Worldwide repaid the loan in full on June 13, 2012 with proceeds from the sale of the Company's oilfield services business. The aggregate amount of principal and interest paid in 2012 was $73.0 million and $1.1 million, respectively.

On August 5, 2010, Viking International entered into an Agreement for Management Services ("Maritas Services Agreement") with Maritas. Pursuant to the Maritas Services Agreement, Viking International agreed to provide management, marketing and personnel services (collectively, the "Maritas Rig Services") from time to time as requested by Maritas for the operation of a drilling rig owned by MAANBE LLC and located in Iraq. Under the terms of the Maritas Services Agreement, Maritas will pay Viking International for all actual costs and expenses associated with the provision of the Maritas Rig Services. In addition, Maritas will pay Viking International a monthly management fee equal to 8% of the total amount invoiced for direct labor costs for employees of Viking International providing Maritas Rig Services under the Maritas Services Agreement. In 2012, Viking International did not provide any goods and Maritas Rig Services to Maritas under the Maritas Services Agreement, and the Maritas Services Agreement was terminated in June 2012.

On September 28, 2010, Viking International entered into an Agreement for Management Services (the "VOS Services Agreement") with VOS. Pursuant to the VOS Services Agreement, Viking International agreed to provide management, marketing, storage and personnel services (collectively, the "VOS Services") from time to time as requested by VOS for the operation of certain equipment owned by VOS that is located in Turkey. Under the terms of the VOS Services Agreement, VOS will pay Viking International for all actual costs and expenses associated with the provision of the VOS Services. In addition, VOS will pay Viking International a monthly management fee equal to 8% of the total amount invoiced for direct labor costs of employees of Viking International providing VOS Services pursuant to VOS Services Agreement. In 2012, the Company did not provide any goods and VOS Services to VOS under the VOS Services Agreement, and the VOS Services Agreement was terminated in June 2012.

Effective January 1, 2011, the Company's wholly-owned subsidiary, TransAtlantic Exploration Mediterranean International Pty Ltd ("TEMI"), entered into an accommodation agreement under which it leases six rooms at a resort hotel owned by Gundem. Under the accommodation agreement, TEMI pays the New Turkish Lira equivalent of $6,000 per month. In 2012, TEMI paid approximately $72,000 to Gundem pursuant to the accommodation agreement.

On August 23, 2011, the Company's wholly-owned subsidiary, TransAtlantic Petroleum (USA) Corp. ("TransAtlantic USA"), entered into an office lease (the "Lease") with Longfellow to lease approximately 5,300 square feet of corporate office space in Addison, Texas. The initial lease term under the lease will commence on the date that TransAtlantic USA subleases or assigns all or a portion of its lease for previous office space in Dallas, Texas (as amended, the "Current Lease") and reaches an agreement to reduce the amount of rent under its Current Lease (the "Commencement Date"), and 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; provided, however, until TransAtlantic USA is able to sublease or assign all or a portion of its Current Lease or enter into an agreement reducing the rent under the Current Lease, no rent, utilities, real property taxes and/or liability insurance is required to be paid to Longfellow under the Lease. TransAtlantic USA paid no rent to Longfellow in 2012.

On March 15, 2012, the Company and its wholly-owned subsidiaries, TransAtlantic Worldwide and TBNG, entered into a $15.0 million credit facility with Dalea to provide additional liquidity for general corporate purposes until the Company completed the sale of its oilfield services business. The Company borrowed $11.0 million under the loan in 2012. Loans under the credit facility accrued interest at a rate of three-month LIBOR plus 5.5% per annum. The Company repaid the loan in full on June 15, 2012 with proceeds from the sale of its oilfield services business. The aggregate amount of principal and interest paid in 2012 was $11.0 million and $0.2 million, respectively.

On April 20, 2012, the Company entered into a Management Services Agreement (the “VOS Agreement”) with VOS. Pursuant to the VOS Agreement, the Company agreed to provide general administrative and technical services including, but not limited to, information technology, accounting, cost accounting, inventory control, tax compliance and reporting system, payroll and benefit, cash management and treasury services (collectively, the “Administrative Services”) from time to time. Under the terms of the VOS Agreement, VOS will pay the Company for all actual costs and expenses associated with the provision of the Administrative Services. In addition, VOS will pay the Company a monthly management fee equal to 8% of the actual costs and expenses invoiced pursuant to the VOS Agreement. For purposes of the VOS Agreement, actual costs and expenses means the direct salary, exclusive of benefits, of the Company’s employees that are allocated to the Administrative Services. In 2012, VOS did not pay the Company for Administrative Services pursuant to the VOS Agreement.

On June 13, 2012, the Company entered into a transition services agreement with Viking Services Management, Ltd. (“Viking Management”) in connection with the sale of its oilfield services business. Pursuant to the transition services agreement, the Company agreed to provide certain administrative services, including, but not limited to, continued use of certain of its 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 the Company with the continued use of certain office space in Tekirdag, Turkey. In the third quarter of 2012, the Company entered into an addendum to the transition services agreement whereby Viking Management agreed to cause its subsidiaries to provide the Company with the continued use of certain equipment yards in the Thrace Basin and in southwestern Turkey. The transition services agreement has a two-year term. Viking Management agreed to use commercially reasonable efforts to eliminate its need for such services as soon as practicable following the entry into the agreement. In 2012, Viking Management did not pay the Company, and the Company did not pay Viking Management, pursuant to the transition services agreement.

On June 13, 2012, the Company also entered into separate master services agreements with each of Viking International, VOS and Viking Geophysical in connection with the sale of its oilfield services business. Pursuant to the master services agreements with Viking International and VOS, the Company is entitled to receive certain oilfield services and materials, including, but not limited to, drilling rigs and fracture stimulation, that are needed for its operations in Bulgaria and Turkey. Pursuant to the master services agreement with Viking Geophysical, the Company is 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, the Company can contract for services and materials on a firm basis and, to the extent that it does 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. In 2012, the Company paid Viking International, VOS and Viking Geophysical approximately $55.5 million under the master service agreements.

On June 13, 2012, the Company closed the sale of its oilfield services business, which was substantially comprised of the Company's 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 the Company's 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, the Company 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. The Company used a portion of the net proceeds from the sale to pay off its $73.0 million credit agreement with Dalea, its $11.0 million credit facility with Dalea, its $0.9 million promissory note with Viking Drilling, LLC and its $1.8 million credit agreement with a Turkish bank. In 2012, Dalea paid the Company $0.2 million in interest.

Policies and Procedures for Approving Related Party Transactions

The Company's board of directors adopted a written Related Party Transactions Policy in December 2009. In accordance with the Company's Related Party Transactions Policy, all Related Party Transactions and any material amendments to such Related Party Transactions must be reviewed and approved by the Company's audit committee and, if necessary, recommended to the Company's board of directors for its approval. Alternatively, the board may determine that a particular Related Party Transaction or a material amendment thereto shall instead be reviewed and approved by a majority of directors disinterested in the Related Party Transaction. If advance audit committee approval of a Related Party Transaction is not feasible, then the Related Party Transaction may be considered and, if the audit committee determines to be appropriate, ratified at the audit committee's next regularly scheduled meeting. In determining whether to approve, recommend or ratify a Related Party Transaction, the audit committee will take into account, among other factors it deems appropriate, (i) whether the transaction is fair to the Company, (ii) whether the audit committee has all of the material facts regarding the transaction or parties involved, (iii) whether the transaction is generally available to an unaffiliated third-party under the same or similar circumstances and cost, and (iv) the extent of the Related Party's interest in the transaction.

A "Related Party Transaction" means a transaction (including any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness)), or a series of transactions, or any material amendment to any such transaction, between the Company and any Related Party (as defined below), other than (i) transactions available to all employees generally; (ii) transactions involving compensation of a director or executive officer or involving an employment agreement, severance agreement, change in control provision or agreement or special supplemental benefit of a director or executive officer; (iii) transactions in which the interest of the Related Party arises solely from the ownership of a class of the Company's equity securities and all holders of that class receive the same benefit on a pro rata basis; or (iv) transactions in which the rates or charges involved therein are determined by competitive bids.

A "Related Party" means the following persons, or an entity owned by any such person: (i) an "executive officer" of the Company (as defined in Rule 405 under the Securities Act and Rule 3b-7 under the Exchange Act); (ii) a director of the Company or a nominee for director of the Company; (iii) a person (including any entity or group) known to the Company to be the beneficial owner of more than 5% of any class of the Company's voting securities (a "5% shareholder"); or (iv) a person who is an "immediate family member" of an executive officer, director, nominee for director or 5% shareholder of the Company.

Item 14. Principal Accountant Fees and Services

Fees paid to KPMG LLP and KPMG Canada

The following table shows the aggregate fees for professional services provided to the Company by KPMG LLP and KPMG Canada for 2012 and 2011:

	2012	2011
Audit Fees	$2,791,000	$2,304,000
Audit-Related Fees	30,000	181,000
Tax Fees	—	70,000
All Other Fees	1,000	500
Total	$2,822,000	$2,555,500

Audit Fees. This category includes the audit of the Company's annual consolidated financial statements, reviews of the Company's financial statements included in the Company's Quarterly Reports on Form 10-Q and services that are normally provided by its independent registered public accounting firm in connection with its engagements for those years. This category also includes advice on audit and accounting matters that arose during, or as a result of, the audit or the review of the Company's interim financial statements.

Audit-Related Fees. This category consists of assurance and related services by its independent registered public accounting firm that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported above under "Audit Fees." The services for the fees disclosed under this category include audit-related work regarding acquisitions, divestitures and debt covenant compliance.

Tax Fees. This category consists of professional services rendered by the Company's independent registered public accounting firm for tax compliance and tax advice. The services for the fees disclosed under this category include tax return preparation and technical tax advice.

All Other Fees. This category consists of fees for other miscellaneous items.

The Company's board of directors has adopted a procedure for pre-approval of all fees charged by its independent registered public accounting firm. Under the procedure, the audit committee of the Company's board of directors approves the engagement letter with respect to audit, tax and review services. Other fees are subject to pre-approval by the audit committee. The audit, audit-related fees, tax fees and other fees paid to KPMG Canada with respect to 2011 and to KPMG LLP with respect to 2012 were pre-approved by the audit committee.

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, 2012 and 2011
   Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2012, 2011 and 2010
   Consolidated Statements of Equity for the years ended December 31, 2012, 2011 and 2010
   Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010
   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.

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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.

May 15, 2013

TRANSATLANTIC PETROLEUM LTD.

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

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

Signature	Capacity	Date
/S/ N. MALONE MITCHELL, 3rd **N. Malone Mitchell, 3rd**	Chairman and Chief Executive Officer (Principal Executive Officer)	May 15, 2013
/S/ WIL F. SAQUETON **Wil F. Saqueton**	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer/Controller)	May 15, 2013
/S/ BOB G. ALEXANDER **Bob G. Alexander**	Director	May 15, 2013
/S/ BRIAN E. BAYLEY **Brian E. Bayley**	Director	May 15, 2013
/S/ CHARLES J. CAMPISE **Charles J. Campise**	Director	May 15, 2013
/S/ MEL G. RIGGS **Mel G. Riggs**	Director	May 15, 2013
/S/ MICHAEL D. WINN **Michael D. Winn**	Director	May 15, 2013

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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 Pertroleum 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).
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	Memorandum of Continuance of TransAtlantic Petroleum Ltd., dated August 20, 2009 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
3.3	Bye-Laws of TransAtlantic Petroleum Ltd., dated July 14, 2009 (incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K dated October 1, 2009, filed with the SEC on October 7, 2009).
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	Common Share Purchase Warrant, dated September 1, 2010, by and between TransAtlantic Petroleum Ltd. and Dalea Partners, LP (uncorporated by reference to Exhibit 4.4 to the Company's Annual Report on Form 10-K, filed with the SEC on April 21, 2011).
4.4	Form of Common Share Certificate (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-3, filed with the SEC on June 9, 2010).
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	Agreement for Management Services, dated September 28, 2010, by and between Viking International Limited and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated September 28, 2010, filed with the SEC on September 28, 2010).
10.4	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).

10.5†	Amended and Restated Stock Option Plan (2006) (incorporated by reference to Exhibit 4.4 to the Company’s Registration Statement on Form 20-F (File No. 000-31643), filed with the SEC on October 9, 2007).
10.6†	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).
10.7†	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).
10.8†	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).
10.9†	Form of Share Option Agreement (incorporated by reference to Exhibit 99.3 to the Company’s Registration Statement on Form S-8, filed with the SEC on November 2, 2009).
10.10	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).
10.11	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).
10.12	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).
10.13	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).
10.14†	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).
10.15	Management Services Agreement, effective as of February 1, 2012, by and between TransAtlantic Petroleum Ltd. and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K, dated April 20, 2012, filed with the SEC on April 26, 2012).

10.16	Management Services Agreement, dated March 15, 2012, by and between Viking Geophysical Services, Ltd. and Viking Petrol Sahasi Hizmetleri A.S. (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the SEC on May 10, 2012).
10.17	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).
10.18	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).
10.19	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).
10.20	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).
10.21	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).
10.22*	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.
21.1*	Subsidiaries of the Company.
23.1*	Consent of KPMG LLP.
23.2*	Consent of KPMG Canada.
23.3*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Chief Executive Officer of the Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of the 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 February 28, 2013.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.

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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.
** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND FINANCIAL STATEMENT SCHEDULES

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
TransAtlantic Petroleum Ltd.

We have audited the accompanying consolidated balance sheet of TransAtlantic Petroleum Ltd. and subsidiaries (the Company) as of December 31, 2012, and the related consolidated statements of comprehensive income (loss), equity and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We 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 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 audit provides 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 the Company as of December 31, 2012, and the results of their operations and their cash flows for the year then ended, 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, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated May 15, 2013 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
May 15, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
TransAtlantic Petroleum Ltd.:

We have audited TransAtlantic Petroleum Ltd. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* 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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. Management has identified and included the following material weaknesses in management's assessment (included in Item 9A(b)):

- The Company has not maintained a sufficient complement of qualified personnel with U.S. GAAP knowledge and expertise, which resulted in the ineffective design or operation of the Company's internal controls over significant account balances and estimates.
- The Company's management review and approval controls were not complete and comprehensive, and not operating at a sufficient level of precision, to prevent or detect material misstatements in the Company's financial statements.
- The Company has not designed and implemented effective internal controls around the accounting for oil & gas properties.
- The Company has not designed and implemented effective internal controls over income tax provisions.

- The Company has not designed and implemented effective internal controls over significant non-routine transactions.
- The Company has not designed and implemented effective controls over remeasurement and translation of its foreign entity account balances.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of TransAtlantic Petroleum Ltd. and subsidiaries as of December 31, 2012, and the related consolidated statements of comprehensive income (loss), equity and cash flows for the year then ended. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2012 consolidated financial statements, and this report does not affect our report dated May 15, 2013, which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, because of the effect of the aforementioned material weaknesses on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We do not express an opinion or any other form of assurance on management's statements referring to corrective actions taken after December 31, 2012, relative to the aforementioned material weaknesses in internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas

May 15, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
TransAtlantic Petroleum Ltd:

We have audited the accompanying consolidated balance sheet of TransAtlantic Petroleum Ltd. and subsidiaries ("the Company") as of December 31, 2011, and the related consolidated statements of comprehensive income (loss), equity and cash flows for each of the years in the two-year period ended December 31, 2011. 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, 2011, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Calgary, Canada
March 23, 2012 (except Note 2 dated May 15, 2013)

TRANSATLANTIC PETROLEUM LTD.

Consolidated Balance Sheets
As of December 31, 2012 and 2011
(in thousands of U.S. Dollars, except share data)

	2012	2011 (See Note 2)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14,768	$ 15,116
Accounts receivable		
Oil and natural gas sales, net	34,158	28,495
Related party	419	—
Joint interest and other, net	18,192	23,141
Prepaid and other current assets	2,339	4,142
Deferred income taxes	1,895	2,124
Assets held for sale	1,619	127,168
Total current assets	73,390	200,186
Property and equipment :		
Oil and natural gas properties (successful efforts method)		
Proved	231,498	174,608
Unproved	68,938	70,393
Equipment and other property	35,747	39,914
	336,183	284,915
Less accumulated depreciation, depletion and amortization	(80,031)	(49,486)
Property and equipment, net	256,152	235,429
Other long-term assets:		
Other assets	8,195	4,673
Note receivable – related party	11,500	—
Goodwill	9,021	8,514
Total other assets	28,716	13,187
Total assets	$ 358,258	$ 448,802
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 12,864	$ 25,855
Accounts payable – related party	15,915	323
Accrued liabilities	29,691	25,104
Loans payable	—	7,732
Loan payable – related party	—	73,000
Derivative liabilities	3,908	3,716
Asset retirement obligations	818	3,031
Liabilities held for sale – related party	—	3,677
Liabilities held for sale	8,416	22,187
Total current liabilities	71,612	164,625
Long-term liabilities:		
Asset retirement obligations	11,140	10,503
Accrued liabilities	7,548	5,538
Deferred income taxes	16,483	15,508
Loan payable	32,766	78,000
Derivative liabilities	4,882	3,355
Total long-term liabilities	72,819	112,904
Total liabilities	144,431	277,529
Commitments and contingencies		
Shareholders' equity:		
Common shares, $0.01 par value, 1,000,000,000 shares authorized, 368,748,592 issued and outstanding as of December 31, 2012 and 365,790,492 as of December 31, 2011	3,687	3,658
Additional paid-in capital	537,962	533,907
Accumulated other comprehensive loss	(28,012)	(50,236)
Accumulated deficit	(299,810)	(316,056)
Total shareholders' equity	213,827	171,273
Total liabilities and shareholders' equity	$ 358,258	$ 448,802

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, 2012, 2011 and 2010
(U.S. Dollars and shares in thousands, except per share amounts)

	2012	2011 (See Note 2)	2010
Revenues:			
Oil and natural gas sales	$134,113	$ 124,162	$ 69,839
Sales of purchased natural gas	7,882	2,668	—
Other	1,913	2,075	1,015
Total revenues	143,908	128,905	70,854
Costs and expenses:			
Production	17,804	18,475	20,286
Exploration, abandonment and impairment	39,993	60,952	12,691
Costs of purchased natural gas	7,694	2,645	—
Seismic and other exploration	5,040	11,542	16,883
Revaluation of contingent consideration	—	6,000	—
General and administrative	33,947	36,305	26,049
Depreciation, depletion and amortization	28,215	39,008	13,998
Accretion of asset retirement obligations	710	1,142	470
Total costs and expenses	133,403	176,069	90,377
Operating income (loss)	10,505	(47,164)	(19,523)
Other (expense) income:			
Interest and other expense	(8,340)	(13,665)	(7,055)
Interest and other income	2,418	1,089	267
Loss on commodity derivative contracts	(5,548)	(8,426)	(1,624)
Foreign exchange gain (loss)	1,083	(11,973)	(1,872)
Total other expense	(10,387)	(32,975)	(10,284)
Income (loss) from continuing operations before income taxes	118	(80,139)	(29,807)
Current income tax expense	(4,674)	(2,386)	(2,076)
Deferred income tax (expense) benefit	(1,817)	4,951	2,338
Net loss from continuing operations	$ (6,373)	$ (77,574)	$ (29,545)
Loss from discontinued operations before income taxes	(5,083)	(39,114)	(39,470)
Gain on disposal of discontinued operations	35,999	—	—
Income tax provision	(8,297)	(4,255)	(731)
Net income (loss) from discontinued operations	22,619	(43,369)	(40,201)
Net income (loss)	16,246	(120,943)	(69,746)
Other comprehensive income (loss):			
Foreign currency translation adjustment	22,224	(52,069)	(7,768)
Comprehensive income (loss)	$ 38,470	$(173,012)	$ (77,514)
Net loss per common share:			
Basic net income (loss) per common share:			
From continuing operations	$ (0.02)	$ (0.22)	$ (0.09)
From discontinued operations	$ 0.06	$ (0.12)	$ (0.13)
Basic weighted average shares outstanding	367,415	355,971	312,488
Diluted net income (loss) per common share:			
From continuing operations	$ (0.02)	$ (0.22)	$ (0.09)
From discontinued operations	$ 0.06	$ (0.12)	$ (0.13)
Diluted weighted average shares outstanding	367,415	355,971	312,488

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

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TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Equity
For the years ended December 31, 2012, 2011 and 2010
(U.S. Dollars and shares in thousands)

	Common Shares	Common Shares ($)	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Shareholders' Equity
Balance at December 31, 2009	303,266	$ 3,033	$377,340	$ 9,601	$ (125,367)	$ 264,607
Issuance of common shares	30,357	304	84,696	—	—	85,000
Issuance costs	—	—	(4,350)	—	—	(4,350)
Issuance of warrants	—	—	4,330	—	—	4,330
Exercise of warrants	731	7	871	—	—	878
Exercise of stock options	1,212	12	1,078	—	—	1,090
Issuance of restricted stock units	877	8	(8)	—	—	—
Share-based compensation	—	—	2,016	—	—	2,016
Foreign currency translation adjustments	—	—	—	(7,768)	—	(7,768)
Net loss	—	—	—	—	(69,746)	(69,746)
Balance at December 31, 2010	336,443	$ 3,364	$465,973	$ 1,833	$ (195,113)	$ 276,057
Issuance of common shares	27,424	274	65,763	—	—	66,037
Exercise of warrants	80	1	95	—	—	96
Exercise of stock options	845	8	620	—	—	628
Issuance of restricted stock units	998	11	(11)	—	—	—
Tax withholding on restricted stock units	—	—	(210)	—	—	(210)
Share-based compensation	—	—	1,677	—	—	1,677
Foreign currency translation adjustments	—	—	—	(52,069)	—	(52,069)
Net loss	—	—	—	—	(120,943)	(120,943)
Balance at December 31, 2011 (See Note 2)	365,790	$ 3,658	$533,907	$ (50,236)	$ (316,056)	$ 171,273
Issuance of common shares	—	—	—	—	—	—
Exercise of stock options	805	8	656	—	—	664
Issuance of restricted stock units	2,154	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
Balance at December 31, 2012	368,749	$ 3,687	$537,962	$ (28,012)	$ (299,810)	$ 213,827

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

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TRANSATLANTIC PETROLEUM LTD.

Consolidated Statements of Cash Flows
For the years ended December 31, 2012, 2011 and 2010
(in thousands of U.S. Dollars)

	2012	2011 (See Note 2)	2010
Operating activities:			
Net income (loss)	$ 16,246	$(120,943)	$ (69,746)
Adjustment for net (income) loss from discontinued operations	(22,619)	43,369	40,201
Net loss from continuing operations	(6,373)	(77,574)	(29,545)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities from continuing operations:			
Share-based compensation	2,559	1,212	1,773
Foreign currency (gain) loss	3,843	14,690	597
Unrealized loss on commodity derivative contracts	1,719	3,572	1,595
Amortization of loan financing costs	1,991	1,630	1,336
Deferred income tax expense (benefit)	1,817	(4,951)	(2,338)
Inventory write down	1,390	—	—
Amortization of warrants – related party	—	1,972	2,358
Exploration, abandonment and impairment	22,617	52,638	5,343
Depreciation, depletion and amortization	28,215	39,008	13,998
Accretion of asset retirement obligations	710	1,142	470
Loss on revaluation of contingent consideration	—	6,000	—
Changes in operating assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(6,872)	(4,985)	(19,135)
Prepaid expenses and other assets	(1,149)	(4,492)	5,959
Accounts payable and accrued liabilities	1,503	21,145	(1,963)
Net cash provided by (used in) operating activities from continuing operations	51,970	51,007	(19,552)
Net cash used in operating activities from discontinued operations	(25,769)	(10,602)	(23,944)
Net cash provided by (used in) operating activities	26,201	40,405	(43,496)
Investing activities:			
Deposit on acquisitions	—	—	(10,000)
Acquisitions, net of cash	—	(747)	(96,248)
Additions to oil and natural gas properties	(52,813)	(68,713)	(52,664)
Additions to equipment and other properties	(668)	(2,648)	(11,405)
Restricted cash	949	5,132	(173)
Net cash used in investing activities from continuing operations	(52,532)	(66,976)	(170,490)
Net cash provided by (used in) investing activities from discontinued operations	156,149	(4,761)	(48,517)
Net cash provided by (used in) investing activities	103,617	(71,737)	(219,007)
Financing activities:			
Exercise of stock options and warrants	664	722	1,968
Issuance of common shares	—	—	80,000
Issuance of common shares – related party	—	—	5,000
Tax withholding on restricted stock units	(147)	(210)	—
Issuance costs	—	—	(4,350)
Loan proceeds	25,967	35,967	55,886
Loan proceeds – related party	11,000	—	91,500
Loan repayment	(78,931)	(18,024)	(2,445)
Loan repayment – related party	(84,000)	—	(18,500)
Loan financing costs	(250)	—	(1,028)
Net cash (used in) provided by financing activities from continuing operations	(125,697)	18,455	208,031
Net cash used in financing activities from discontinued operations	(5,049)	(5,068)	(1,134)
Net cash (used in) provided by financing activities	(130,746)	13,387	206,897
Effect of exchange rate changes on cash	580	(1,615)	(202)
Net decrease in cash and cash equivalents	(348)	(19,560)	(55,808)
Cash and cash equivalents, beginning of year	15,116	34,676	90,484
Cash and cash equivalents, end of year	$ 14,768	$ 15,116	$ 34,676
Supplemental disclosures:			
Cash paid for interest	$ 6,946	$ 10,106	$ 3,062
Cash paid for income taxes	$ 5,596	$ 7,729	$ 5,649
Supplemental non-cash investing and financing activities:			
Note receivable – related party from sale of oilfield services business	$ 11,500	$ —	$ —
Issuance of common shares for acquisitions	$ —	$ 66,037	$ —
Repayment of short-term credit facility from refinancing	$ —	$ 30,000	$ —

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. As of December 31, 2012, we held interests in developed and undeveloped oil and natural gas properties in Turkey, Bulgaria and Romania. As of May 1, 2013, approximately 40% 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.

Reclassification

During the year ended December 31, 2012, we reclassified certain balance sheet amounts previously reported on our consolidated balance sheet at December 31, 2011 to conform to current year presentation. Specifically, we reclassified $12.2 million of joint interest receivables out of accounts receivable, oil and natural gas sales, net to accounts receivable, joint interest and other, net, and a liability held for sale which should have been netted with assets held for sale of approximately $0.9 million. We reclassified the revenue and cost related to natural gas purchased from third parties. For the year ended December 31, 2011, these reclassifications increased total revenues and expenses by approximately $2.7 million and $2.6 million, respectively. We also reclassified depreciation expense from continuing operations to discontinued operations for the years ended December 31, 2011 and 2010 of $2.7 million and $2.4 million, respectively.

Change to going concern assumption

As a result of recurring losses from continuing operations and a working capital deficiency at December 31, 2011 and March 31, 2012, we stated in our Annual Report on Form 10-K for the year ended December 31, 2011 and our Quarterly Report on Form 10-Q for the three months ended March 31, 2012 that there was substantial doubt regarding our ability to continue as a going concern. At that time, we stated that should we be unable to consummate the sale of our oilfield services business, raise additional financing or extend the maturity date of our credit agreement with Dalea Partners, LP (“Dalea”), an affiliate of Mr. Mitchell, we would not have sufficient funds to continue operations beyond June 30, 2012.

On June 13, 2012, we closed the sale of our oilfield services business, which was substantially comprised of our wholly owned subsidiaries Viking International Limited (“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. 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, LLC (“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 to pay down approximately $45.2 million in outstanding indebtedness under our amended and restated senior secured credit facility with Standard Bank Plc (“Standard Bank”) and BNP Paribas (Suisse) SA (as amended, the “Amended and Restated Credit Facility”).

As of December 31, 2012, we had no short-term debt and availability of $26.9 million under our Amended and Restated Credit Facility. In addition, at December 31, 2012, we had net working capital of $8.6 million, excluding assets and liabilities held for sale. As a result, management believes that the conditions that led to the substantial doubt about our ability to continue as a going concern at December 31, 2011 and March 31, 2012 no longer existed at December 31, 2012.

2. Revision of prior period financial statements and out-of-period adjustments

During the three months ended June 30, 2012 and September 30, 2012, we identified and corrected errors that originated in prior periods. We assessed the materiality of the errors in accordance with the Securities and Exchange Commission (“SEC”) guidance on considering the effects of prior period misstatements based on an analysis of quantitative and qualitative factors. Based on this analysis, we determined that the errors were immaterial to each of the prior reporting periods affected and, therefore, amendments of reports previously filed with the SEC were not required. However, we also concluded that correcting the errors in our 2012 financial statements would materially understate results for the year ended December 31, 2012. Accordingly, we reflected the correction of these prior period errors in the periods in which they originated and revised our consolidated balance sheet and consolidated statement of equity for the year ended December 31, 2011, our consolidated statement of cash flows for the year ended December 31, 2011 and our consolidated statement of comprehensive income (loss) for the year ended December 31, 2011 in this Annual Report on Form 10-K. In addition, a reduction to retained earnings has been reflected as an adjustment to the beginning balance for the year ended December 31, 2012.

These errors consisted mainly of accrued liabilities that should have been recorded in prior periods, errors in foreign currency gain/loss remeasurement, inappropriate recognition of receivable balances, and other minor corrections with immaterial impact to other miscellaneous accounts. We also reclassified a receivable balance which had been netted with a payable balance of approximately $10.5 million, a prepaid balance which should have been netted with a payable balance of approximately $2.4 million, and sales of purchased natural gas of $2.7 million and costs of purchased natural gas of $2.6 million which had previously been netted with other revenues.

Additionally, we increased our gain on the sale of our oilfield services business during the three months ended September 30, 2012 by $5.1 million. This revision was primarily due to an intercompany balance that was not contemplated as part of the gain at June 30, 2012.

The reclassification discussed under the sub-heading “Reclassification” in Note 1 was reflected in the December 31, 2011 consolidated balance sheet. The condensed version of that consolidated balance sheet is presented below under the column titled “As Reported”, prior to any immaterial corrections discussed above. The effects of the immaterial corrections on the consolidated balance sheet as of December 31, 2011 were as follows (in thousands):

	As Reported	Correction	As Revised
As of December 31, 2011			
Accounts receivable	$ 42,694	$ 8,942	$ 51,636
Other assets	401,299	(4,133)	397,166
Total assets	$443,993	$ 4,809	$448,802
Accrued liabilities, current	$ 16,450	$ 8,654	$ 25,104
Other liabilities	251,339	1,086	252,425
Total liabilities	267,789	9,740	277,529
Accumulated other comprehensive loss	(50,615)	379	(50,236)
Other shareholders’ equity	226,819	(5,310)	221,509
Total shareholders’ equity	176,204	(4,931)	171,273
Total liabilities and shareholders’ equity	$443,993	$ 4,809	$448,802

The effect of the corrections on the consolidated statement of comprehensive loss for the year ended December 31, 2011 was as follows (in thousands):

	As Reported	Correction	As Revised
For the year ended December 31, 2011			
Total revenues	$ 126,338	$ 2,567	$ 128,905
Total costs and expenses	(171,980)	(4,089)	(176,069)
Total other (expense) income	(32,683)	(292)	(32,975)
Loss from continuing operations before income taxes	(78,325)	(1,814)	(80,139)
Net loss from continuing operations	(75,220)	(2,354)	(77,574)
Net loss from discontinued operations	(40,623)	(2,746)	(43,369)
Net loss	(115,843)	(5,100)	(120,943)
Foreign currency translation adjustment	(52,448)	379	(52,069)
Comprehensive loss	$(168,291)	$ (4,721)	$(173,012)

Additionally, during the fourth quarter of 2012 we identified and corrected errors that originated in prior periods that were not material to our consolidated financial statements for the years ended December 31, 2012, 2011, 2010 and 2009.

These errors consisted mainly of an overstatement of depreciation, depletion and amortization expense of approximately $4.7 million, which was offset by a related understatement of exploration, abandonment and impairment expense of $4.5 million. Additionally, there was an overstatement of deferred income tax expense of $1.5 million, an understatement of foreign exchange loss of $2.0 million and an understatement of other miscellaneous accounts of $1.0 million. The impact of these errors resulted in a decrease to our net loss for the fourth quarter of 2012 of approximately $1.3 million.

3. Significant accounting policies

Basis of preparation

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

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 (expense) income.

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 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 translation

The functional currency of our corporate entities in Morocco, Turkey and Romania is the Moroccan Dirham, New Turkish Lira and the Romanian New Leu, 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 re-measuring transactions and monetary accounts in a currency other than the functional currency are included in earnings. For certain of our controlled entities, 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. The accounting basis of the assets and liabilities affected by the change are adjusted to reflect the difference between the exchange rate when the asset or liability arose and the exchange rate on the date of the change.

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 operations.

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. Oil and natural gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment on proved properties is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset 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 an independent expert. 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 cost 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, 2012 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.

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 income in the period that includes the enactment date.

For the year ended December 31, 2012, we recognized an uncertain tax position liability of approximately $6.3 million related to our August 2010 acquisition of Amity and Petrogas (See Note 13). 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 benefits 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. Accordingly, transaction costs related to acquisitions are to be recorded as a reduction of earnings in the period they are incurred and costs related to issuing debt or equity securities that are related to the transaction will continue to be recognized in accordance with other applicable rules under U.S. GAAP. ASC 810-10-65 requires non-controlling interests to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for non-controlling interests and transactions with non-controlling interest holders in consolidated financial statements.

Per share information

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

4. New accounting pronouncements

In May 2011, FASB issued ASU 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS s* ("ASU 2011-04"). ASU 2011-04 amends ASC 820, providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurement and expands the ASC 820 disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 became effective for interim and annual periods beginning after December 15, 2011. We adopted ASU 2011-04 on January 1, 2012. The adoption did not have a material effect on our financial statements.

In June 2011, FASB issued ASU 2011-05, *Presentation of Comprehensive Income* ("ASU 2011-05"). ASU 2011-05 requires the presentation of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. In December 2011, FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU 2011-05* ("ASU 2011-12"). ASU 2011-12 defers the specific requirement to present items that are reclassified from accumulated other comprehensive income to net income separately with their respective components of net income and other comprehensive income. The amendments became effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. We adopted ASU 2011-05 on January 1, 2012. The adoption did not have a material effect on our financial statements.

In September 2011, FASB issued ASU 2011-08, *Testing Goodwill for Impairment* ("ASU 2011-08"). ASU 2011-08 allows both public and nonpublic entities an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity would no longer be required to calculate the fair value of a reporting unit unless the entity determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. We adopted ASU 2011-08 on January 1, 2012. The adoption did not have a material effect on our financial statements.

In December 2011, FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities* ("ASU 2011-11"). ASU 2011-11 requires entities to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. ASU 2011-11 will be effective for annual reporting periods beginning on or after January 1, 2013 and interim periods within those annual periods. The adoption of ASU 2011-11 is not expected to have a material effect on our financial statements.

In July 2012, FASB issued ASU 2012-02, *Testing Indefinite-Lived Intangible Assets for Impairment* ("ASU 2012-02"). The update provides an entity with the option first to assess qualitative factors in determining whether it is more likely than not that the indefinite-lived intangible asset is impaired. After assessing the qualitative factors, if an entity determines that it is not more likely than not that the indefinite-lived intangible asset is impaired, then the entity is not required to take further action. If an entity concludes otherwise, then it is required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. Early adoption was permitted. We did not early adopt the provisions of ASU 2012-02. We do not expect the adoption of ASU 2012-02 to have a material effect on our financial statements.

In February 2013, FASB issued ASU 2013-09, *New Disclosures for Items Reclassified Out of Accumulated Other Comprehensive Income* ("ASU 2013-09"). ASU 2013-09 requires reclassification adjustments for items that are reclassified out of accumulated other comprehensive income to net income to be presented in the statements where the components of net income and the components of other comprehensive income are presented or in the footnotes to the financial statements. Additionally, the amendment requires cross-referencing to other disclosures currently required for other reclassification items. The amendments are effective for interim and annual reporting periods beginning after December 15, 2012. The adoption of ASU 2013-09 is not expected to have a material impact on our financial statements.

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.

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5. Acquisitions

TBNG

On June 7, 2011, TransAtlantic Worldwide, Ltd. ("TransAtlantic Worldwide") acquired Thrace Basin Natural Gas (Turkiye) Corporation ("TBNG") in exchange for cash consideration of $10.5 million and the issuance of 18,500,000 of our common shares (at a deemed price of $2.05 per common share). Of the $10.5 million cash consideration, $10.0 million was paid in November 2010 as an option fee and applied to the purchase price. We engaged independent valuation experts to assist in the determination of the fair value of the assets and liabilities acquired in the acquisition. The following tables summarize the consideration paid in the acquisition and the final recognized amounts of assets acquired and liabilities assumed that have been recognized at the acquisition date:

Consideration:

	(in thousands)
Cash consideration, net of purchase price adjustments	$ 10,504
Issuance of 18,500,000 common shares	37,925
Fair value of total consideration transferred	$ 48,429

Acquisition-Related Costs:

Included in general and administrative expenses on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011	$1,013

Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed at Acquisition:

Assets:	
Cash	$ 1,845
Accounts receivable	19,997
Restricted cash	4,931
Total financial assets	26,773
Other current assets, consisting primarily of prepaid expenses	3,272
Deferred tax asset	722
Oil and natural gas properties:	
Proved properties	14,526
Unproved properties	16,131
Land and buildings	2,601
Drilling services equipment and vehicles	19,512
Total oil and natural gas properties and other equipment	52,770
Liabilities:	
Accounts payable, consisting of normal trade obligations	5,960
Other current liabilities	5,596
Asset retirement obligation	6,480
Deferred tax liability	2,523
Bank loans	14,549
Total liabilities	35,108
Total identifiable net assets	$48,429

As of the date of acquisition, the fair value of the accounts receivable that were acquired was $20.0 million, consisting of a gross amount of $23.5 million, of which $3.5 million is not expected to be collected.

We finalized our purchase accounting in December 2011, resulting in additional accrued liabilities, increases in unproved properties and adjustments to deferred tax liabilities.

The results of operations of TBNG are included in our consolidated results of operations beginning June 7, 2011. The revenues and loss of TBNG included in our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011 were:

	Revenue	Loss
	(in thousands)	
Actual from June 7, 2011 through December 31, 2011	$13,466	$(4,651)

Direct

On February 18, 2011, TransAtlantic Worldwide acquired Direct Petroleum Morocco, Inc. ("Direct Morocco") and Anschutz Morocco Corporation ("Anschutz"), and our wholly owned subsidiary TransAtlantic Petroleum Cyprus Limited acquired Direct Petroleum Bulgaria EOOD ("Direct Bulgaria") for cash consideration of $2.4 million and the issuance of 8,924,478 of our common shares (at a deemed price of $3.15 per common share) to the seller, Direct Petroleum Exploration, Inc. ("Direct"), in a private placement, for total consideration of $34.5 million. At the time of the acquisition, Direct Morocco and Anschutz owned a 50% working interest in the Ouezzane-Tissa and Asilah exploration permits in Morocco, and Direct Bulgaria owned 100% of the working interests in the A-Lovech and Aglen exploration permits in Bulgaria.

The following tables summarize the consideration paid in the acquisition of Direct Morocco, Anschutz and Direct Bulgaria and the final recognized amounts of assets acquired and liabilities assumed which have been recognized at the acquisition date:

Consideration:

	(in thousands)
Cash consideration, net of purchase price adjustments	$ 2,408
Issuance of 8,924,478 common shares	28,112
Contingent consideration liabilities	4,000
Fair value of total consideration transferred	$ 34,520

If certain post-closing milestones are achieved, we will issue additional consideration to Direct equal to: (i) $10.0 million worth of our common shares if the Deventci-R2 well in Bulgaria is a commercial success and (ii) $10.0 million worth of our common shares if Direct Bulgaria receives a production concession for a specified area in Bulgaria. The fair value of these contingent consideration liabilities represents our best estimate of the amounts to be paid as additional consideration. Subsequent changes in the fair value of the contingent consideration liabilities are reflected in our consolidated statements of comprehensive income (loss). The fair value of these contingent consideration liabilities was $10.0 million at December 31, 2012 and 2011 and the increase in the contingent consideration liabilities since the acquisition date was included under the caption “Revaluation of contingent consideration” on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011.

Acquisition-Related Costs:

	(in thousands)
Included in general and administrative expenses on our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011	$ 117

Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed at Acquisition:

	(in thousands)
Assets:	
Cash	$ 320
Accounts receivable	57
Total financial assets	377
Other current assets, consisting primarily of prepaid expenses	146
Oil and natural gas properties:	
Proved properties	1,200
Unproved properties	32,840
Other equipment	79
Total oil and natural gas properties and other equipment	34,119
Liabilities:	
Accounts payable, consisting of normal trade obligations	122
Total identifiable net assets	$ 34,520

The results of operations of Direct Morocco, Anschutz and Direct Bulgaria are included in our consolidated results of operations beginning February 18, 2011, the closing date of the acquisition.

The amounts of revenue and loss of Direct Morocco, Anschutz and Direct Bulgaria included in our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011 are shown below:

	Revenue	Loss
	(in thousands)	
Continuing operations	$ 483	$(30,749) [(1)]
Discontinued operations	—	(7,021)
Total from February 18, 2011 through December 31, 2011	$ 483	$(37,770)

(1) See Note 7. Property and Equipment for a discussion of the impairment of our properties in Bulgaria.

Pro forma results of operations

The following table presents the unaudited pro forma results of operations for the year ended December 31, 2011 as though the acquisitions of Direct Morocco, Anschutz, Direct Bulgaria and TBNG had occurred as of January 1, 2011 (in thousands, except per share amounts):

	2011
Total revenues	$ 139,999
Loss from continuing operations before income taxes	(82,856)
Loss from continuing operations	(80,834)
Loss from discontinued operations	(45,071)
Net loss	(125,905)
Net loss per common share from continuing operations	
Basic	$ (0.22)
Diluted	$ (0.22)
Net loss per common share from discontinued operations	
Basic	$ (0.12)
Diluted	$ (0.12)

6. 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, 2012 and 2011:

	2012	2011
	(in thousands)	
Goodwill at January 1,	$8,514	$10,341
Foreign exchange change effect	507	(1,827)
Goodwill at December 31,	$9,021	$ 8,514

7. 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:

	December 31, 2012	December 31, 2011 (as adjusted)
	(in thousands)	
Oil and natural gas properties, proved:		
Turkey	$229,462	$ 172,917
Bulgaria	2,036	1,691
Total oil and natural gas properties, proved	231,498	174,608
Oil and natural gas properties, unproved:		
Turkey	68,938	70,393
Gross oil and natural gas properties	300,436	245,001
Accumulated depletion	(74,099)	(45,327)
Net oil and natural gas properties	$226,337	$ 199,674

At December 31, 2012 and 2011, we excluded $1.8 million and $7.1 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, 2012, the capitalized costs of our oil and natural gas properties included $49.5 million relating to acquisition costs of proved properties before the fourth quarter impairment which are being amortized by the unit-of-production method using total proved reserves and $105.3 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, 2011, the capitalized costs of our oil and natural gas properties included $61.8 million relating to acquisition costs of proved properties which are being amortized by the unit-of-production method using total proved reserves and $60.0 million relating to well costs and additional development costs which are being amortized by the unit-of-production method using proved developed reserves.

During the year ended December 31, 2012, we incurred approximately $38.6 million in exploratory drilling costs, of which $19.6 million was included in exploration, abandonment and impairment expense, $11.6 million was reclassified from unproved to proved properties and $7.4 million remained capitalized at December 31, 2012. Approximately $4.3 million of exploratory drilling costs incurred in prior periods was expensed to exploration, abandonment, and impairment in 2012. We transferred $5.0 million of our exploratory well costs to proved properties in 2011. Uncertainties affect the recoverability of costs of our oil and natural gas properties, as the recovery of the costs are dependent upon us maintaining licenses in good standing and achieving commercial production or sale.

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. During the year ended December 31, 2012, we recorded $2.7 million in impairment charges on our proved properties primarily 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 3864. During the year ended December 31, 2011, we recorded a $30.2 million impairment on our unproved oil and natural gas properties. Of this amount, $25.9 million was attributable to our Bulgarian properties. We impaired our Bulgarian properties following the enactment by the Bulgarian Parliament of legislation which banned fracture stimulation in the Republic of Bulgaria.

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. For the year ended December 31, 2011, we recorded $14.6 million in impairment charges on two of our proved properties in Turkey primarily due to downward revisions in natural gas reserves in the Alpullu and Edirne fields.

As of December 31, 2012, we had $4.3 million of exploratory well costs capitalized for the Pancarkoy-1 well, which we began drilling in the fourth quarter of 2010. After the second fracture stimulation of the Pancarkoy-1 well, commercial natural gas production could not be sustained due to high water production. A third fracture stimulation of the Pancarkoy-1 well was performed in April 2012, but commercial production could not be sustained due to high water production. In the fourth quarter of 2012, we tested the up-hole interval of the well. Based on the test results, further fracture stimulation of this well is planned in the third quarter of 2013. In June 2012, based on the test results, we wrote off a portion of the exploratory well costs related to this well, with only the sidetrack wellbore costs remaining capitalized.

The Meneske-1 well was spud in November 2011, and we have capitalized $2.0 million of exploratory well costs as of December 31, 2012. Due to expected high tie-in costs of the Meneske-1 well, we are waiting on the test results of other nearby wells to decide whether to invest capital to tie-in to a pipeline.

The Suleymaniye-2 well was spud in December 2011 and is being evaluated for artificial lift. As of December 31, 2012, we had capitalized $0.8 million of drilling and completion costs for this well.

The following table summarizes the costs related to these wells:

	Year Ended December 31,			Partial Write-Off and Other	Total at December 31,
	2010	2011	2012 (in thousands)		2012
Pancarkoy-1 well initial re-entry and fracture stimulation (Ceylan and Mezardere formations)	$ 799	$4,931	$1,322	$ (2,742)	$ 4,310
Meneske-1 well	—	2,230	144	(347)	2,027
Suleymaniye-2 well	—	—	797	—	797
Total capitalized costs	$ 799	7,161	$2,263	$ (3,089)	$ 7,134

Equipment and other property

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

	December 31,	
	2012	2011
	(in thousands)	
Other equipment	$ 2,013	$ 6,351
Inventory	20,517	19,879
Gas gathering system and facilities	5,369	6,822
Vehicles	131	1,001
Office equipment and furniture	7,717	5,861
Gross equipment and other property	35,747	39,914
Accumulated depreciation	(5,932)	(4,159)
Net equipment and other property	$29,815	$35,755

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, 2012, we excluded $20.5 million of inventory from depreciation as the inventory had not been placed into service.

At December 31, 2011, we excluded $0.5 million of other equipment, $19.9 million of inventory and $1.8 million of gas gathering system and facilities from depreciation as the equipment, inventory and system and facilities had not been placed into service.

8. 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 Arab Medium crude oil pricing. We recognize unrealized and realized gains and losses related to these contracts on a fair value basis in our consolidated statements of comprehensive income (loss) under the caption “Loss on commodity derivative contracts.” Settlements of derivative contracts are included in operating activities on our consolidated statements of cash flows. We are required under our Amended and Restated Credit Facility to hedge between 30% and 75% of our anticipated production volumes in the Selmo and Arpatepe oil fields in Turkey.

During the year ended December 31, 2012, we recorded a net loss on commodity derivative contracts of $5.5 million, consisting of a $1.7 million unrealized loss for changes in fair value and a $3.8 million realized loss for settled contracts.

During the year ended December 31, 2011, we recorded a net loss on commodity derivative contracts of $8.4 million, consisting of a $3.6 million unrealized loss for changes in fair value and a $4.8 million realized loss for settled contracts.

At December 31, 2012, 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, 2012

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, 2013—December 31, 2013	775	$ 82.26	$ 121.36	$ (253)
Collar	January 1, 2014—December 31, 2014	622	$ 80.83	$ 118.07	(292)
					$ (545)

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, 2013—December 31, 2013	831	$ 85.00	$ 97.13	$ 162.13	$ (3,655)
Three-way collar contract	January 1, 2014—December 31, 2014	726	$ 85.00	$ 97.13	$ 162.13	(2,150)
Three-way collar contract	January 1, 2015—December 31, 2015	1,016	$ 85.00	$ 91.88	$ 151.88	(2,440)
						$ (8,245)

At December 31, 2011, 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, 2011

Type	Period	Quantity (Bbl/day)	Weighted Average Minimum Price (per Bbl)	Weighted Average Maximum Price (per Bbl)	Estimated Fair Value of Asset (Liability) (in thousands)
Collar	January 1, 2012—December 31, 2012	960	$ 64.69	$ 106.98	$ (2,529)
Collar	January 1, 2013—December 31, 2013	400	$ 75.00	$ 125.50	(116)
Collar	January 1, 2014—December 31, 2014	380	$ 75.00	$ 124.25	12
					$ (2,633)

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, 2012—December 31, 2012	240	$ 70.00	$ 100.00	$ 129.50	$ (764)
Three-way collar contract	January 1, 2012— March 31, 2012	350	$ 85.00	$ 118.88	$ 138.13	(7)
Three-way collar contract	April 1, 2012— June 30, 2012	350	$ 85.00	$ 116.25	$ 137.38	(35)
Three-way collar contract	July 1, 2012—December 31, 2012	205	$ 85.00	$ 97.13	$ 162.13	(381)
Three-way collar contract	January 1, 2013—December 31, 2013	831	$ 85.00	$ 97.13	$ 162.13	(1,985)
Three-way collar contract	January 1, 2014—December 31, 2014	726	$ 85.00	$ 97.13	$ 162.13	(626)
Three-way collar contract	January 1, 2015—December 31, 2015	1,016	$ 85.00	$ 91.88	$ 151.88	(640)
						$ (4,438)

9. 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, 2012, the net present value of our total ARO was estimated to be $12.0 million, with the undiscounted value being $20.2 million. Total ARO at December 31, 2012 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 5% per annum, and discounted to present value using our credit-adjusted risk-free rate of 5.8% per annum for the years ended December 31, 2012 and 2011. The following table summarizes the changes in our ARO for the years ended December 31, 2012 and 2011:

	2012	2011
	(in thousands)	
Asset retirement obligation January 1,	$13,534	$ 6,943
Acquisitions	—	6,480
Change in estimates (1)	(3,868)	512
Liabilities settled	(110)	(195)
Foreign exchange change effect	793	(2,524)
Additions	899	1,176
Accretion expense	710	1,142
Asset retirement obligation at December 31,	11,958	13,534
Less: current portion	818	3,031
Long-term portion	$11,140	$10,503

(1) For 2012, we used cost estimates provided by third-party engineers. For 2011 and prior years, we used cost estimates provided by internal engineers.

10. Third-party loans payable

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

	December 31, 2012	December 31, 2011
	(in thousands)	
Third-Party Floating Rate Debt		
Amended and Restated Credit Facility	$ 32,766	$ 78,000
Third-Party Fixed Rate Debt		
TBNG credit agreements	—	7,732
Viking International equipment loan	—	— (1)
Total third-party debt	32,766	85,732
Less: short-term third-party debt	—	7,732
Long-term third-party debt	$ 32,766	$ 78,000

(1) $2.1 million outstanding at December 31, 2011, classified as "Liabilities held for sale".

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 the Amended and Restated Credit Facility. 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 is guaranteed by us and each of TransAtlantic Petroleum (USA) Corp. and TransAtlantic Worldwide.

The Amended and Restated Credit Facility matures on the earlier of (i) May 18, 2016 or (ii) the last date of the borrowing base calculation period that immediately precedes the date that the semi-annual report of Standard Bank 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 report prepared by Standard Bank and the Borrowers. The Amended and Restated 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 Amended and Restated Credit Facility accrue interest at a rate of three-month LIBOR plus 5.50% per annum. The Borrowers are also required to pay (i) a commitment fee payable quarterly in arrears at a per annum rate equal to (a) 2.20% 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 Amended and Restated Credit Facility, and (b) 1.10% per annum of the unused and uncancelled portion of the aggregate commitments that exceed the maximum available amount under the Amended and Restated 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 Standard Bank or (b) 5.50% for all other letters of credit.

In November 2012, we entered into an amendment to the Amended and Restated Credit Facility. The amendment, among other things, reduced the commitment fee rates and extended the first commitment reduction date from September 30, 2012 to December 31, 2013. In addition, the amendment provided for a scheduled quarterly reduction of the commitment amount beginning on December 31, 2013, when the commitment amount will be reduced to $67.5 million, and ending on March 31, 2016, when the commitment amount will reach zero.

Availability under the Amended and Restated Credit Facility is subject to a borrowing base. The borrowing base was re-determined semi-annually on April 1st and October 1st of each year prior to September 30, 2012, and is now re-determined quarterly on January 1st, April 1st, July 1st and October 1st of each year. Following our semi-annual borrowing base redetermination on October 1, 2012, the borrowing base at December 31, 2012 was $59.7 million. Following our semi-annual borrowing base redetermination on April 1, 2013, the borrowing base is currently $56.9 million. In June 2012, 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 the Amended and Restated Credit Facility.

At December 31, 2012, we had borrowed $32.8 million under the Amended and Restated Credit Facility.

TBNG credit agreement

TBNG was a party to an unsecured credit agreement with a Turkish bank. In April 2012, we repaid this loan and terminated the TBNG credit agreement.

Viking International equipment loan

In June 2010, Viking International entered into a secured credit agreement with a Turkish bank. In June 2012, we repaid this loan with proceeds from the sale of our oilfield services business.

11. Related party loans payable

We use negotiated interest rates in determining the fair value of our debt. As of the indicated dates, our related-party debt consisted of the following:

	December 31, 2012		December 31, 2011
		(in thousands)	
Related Party Floating Rate Debt			
Dalea credit agreement	$ —		$ 73,000
Dalea credit facility	—		—
Viking Drilling note	—		— (1)
Total related party debt	—		73,000
Less: short-term related party debt	—		73,000
Long-term related party debt	$ —		$ —

(1) $2.9 million outstanding at December 31, 2011, classified as "Liabilities held for sale – related party".

Dalea credit agreement

On June 28, 2010, we entered into a credit agreement with Dalea. The purpose of the Dalea credit agreement was (i) to fund the acquisition of all of the shares of Amity and Petrogas, and (ii) for general corporate purposes. We had borrowed an aggregate of $73.0 million pursuant to the Dalea credit agreement as of December 31, 2011. In June 2012, we repaid the Dalea credit agreement with proceeds from the sale of our oilfield services business.

Dalea credit facility

On March 15, 2012, TransAtlantic Worldwide, TBNG and TransAtlantic Petroleum Ltd. entered into a $15.0 million credit facility with Dalea to provide us with additional liquidity for general corporate purposes until we completed the sale of our oilfield services business. During March 2012, we borrowed a total of $11.0 million pursuant to the Dalea credit facility. In June 2012, we repaid the Dalea credit facility with proceeds from the sale of our oilfield services business.

Viking Drilling note

On July 27, 2009, Viking International purchased the I-13 drilling rig and associated equipment from Viking Drilling. Viking International paid $1.5 million in cash for the drilling rig and entered into a note payable to Viking Drilling in the amount of $5.9 million. On February 19, 2010, Viking International purchased the I-14 drilling rig and associated equipment from Viking Drilling. Viking International paid $1.5 million in cash for the I-14 drilling rig and entered into an amended and restated note payable to Viking Drilling in the amount of $11.8 million, which was comprised of $5.9 million payable related to the I-14 drilling rig and $5.9 million payable related to the purchase of the I-13 drilling rig in July 2009. At December 31, 2011, the outstanding balance under this note was $2.9 million. In June 2012, we repaid this note with proceeds from the sale of our oilfield services business.

12. Shareholders' equity

June 2011 share issuance

On June 7, 2011, we issued 18,500,000 common shares at a deemed price of $2.05 per common share in a private placement to an accredited investor in connection with the acquisition of TBNG.

February 2011 share issuance

On February 18, 2011, we issued 8,924,478 common shares at a deemed price of $3.15 per common share in a private placement to an accredited investor in connection with the acquisition of Direct Morocco, Anschutz and Direct Bulgaria.

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 10%.

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.

In connection with the sale of our oilfield services business, we accelerated the vesting of RSUs for employees of this business, and we recognized $1.0 million in share-based compensation expense during the three months ended June 30, 2012. Total share-based compensation of approximately $3.6 million and $1.7 million with respect to awards of RSUs was recorded for the years ended December 31, 2012 and 2011, respectively. As of December 31, 2012, we had approximately $2.4 million of unrecognized compensation expense related to unvested RSUs, which is expected to be recognized over a weighted average period of 1.6 years.

The following table sets forth RSU activity for the year ended December 31, 2012:

	Number of RSUs (in thousands)	Weighted Average Grant Date Fair Value per RSU
Unvested RSUs outstanding at December 31, 2011	1,429	$ 2.61
Granted	4,371	1.03
Forfeited	(322)	2.00
Vested	(2,330)	1.57
Unvested RSUs outstanding at December 31, 2012	3,148	$ 1.25

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. All options presently outstanding under the Option Plan have a five-year term.

The fair value of stock options is determined using the Black-Scholes Model and is recognized over the service period of the stock option. For the year ended December 31, 2010, we recognized share-based compensation expense of approximately $70,000 with respect to stock options. All stock options were fully vested in 2010, and therefore, no share-based compensation expense for stock option awards was recorded after 2010. We did not grant any stock options during the years ended December 31, 2012, 2011 and 2010.

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Details of the stock options under the Option Plan at December 31, 2012, 2011 and 2010 are presented below.

	2012		2011		2010	
	Number of Options (in thousands)	Weighted Average Exercise Price Per Share	Number of Options (in thousands)	Weighted Average Exercise Price Per Share	Number of Options (in thousands)	Weighted Average Exercise Price Per Share
Outstanding at January 1,	1,135	$ 0.91	2,111	$ 0.86	3,323	$ 0.88
Granted	—	—	—	—	—	—
Expired	(175)	1.00	(131)	1.30	—	—
Exercised	(805)	0.82	(845)	0.74	(1,212)	0.90
Outstanding at December 31,	155	$ 1.23	1,135	$ 0.91	2,111	$ 0.86
Exercisable at December 31,	155	$ 1.23	1,135	$ 0.91	2,111	$ 0.86

The following table summarizes information about outstanding stock options at December 31, 2012:

Options Outstanding and Exercisable			
Shares (in thousands)	Weighted-Average Exercise Price	Intrinsic Value (in thousands)	Weighted-Average Options Exercisable Remaining Contractual Life (years)
155	$1.23	$—	0.44

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, 2012, 2011 and 2010 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, 2012, 2011 and 2010 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 9,594,377, 20,752,128 and 17,799,834 antidilutive common share equivalents from the years ended December 31, 2012, 2011 and 2010, respectively.

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

(in thousands, except per share amounts)	2012	2011 (See Note 2)	2010
Net loss from continuing operations	$ (6,373)	$ (77,574)	$ (29,545)
Net income (loss) from discontinued operations	$ 22,619	$ (43,369)	$ (40,201)
Basic net income (loss) per common share:			
Shares:			
Weighted average common shares outstanding	367,415	355,971	312,488
Basic net income (loss) per common share:			
Continuing operations	$ (0.02)	$ (0.22)	$ (0.09)
Discontinued operations	$ 0.06	$ (0.12)	$ (0.13)
Diluted net income (loss) per common share:			
Shares:			
Weighted average common shares outstanding	367,415	355,971	312,488
Diluted net income (loss) per common share:			
Continuing operations	$ (0.02)	$ (0.22)	$ (0.09)
Discontinued operations	$ 0.06	$ (0.12)	$ (0.13)

Additionally, we had a contingent liability at December 31, 2012 of approximately $10.0 million that is payable in our common shares. At the December 31, 2012 closing price of our common shares, this liability represented 12,048,193 common shares that could be potentially dilutive to future earnings per share calculations.

13. 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 2012, 2011 and 2010) to loss for the year as follows:

	2012	2011 (in thousands)	2010
Statutory tax rate	0.00%	0.00%	0.00%
Income (loss) from continuing operations before income taxes	$ 118	$(80,139)	$(29,807)
Increase (decrease) resulting from:			
Foreign tax rate differentials	8,607	(11,173)	(1,227)
Change in valuation allowance	(2,026)	6,871	586
Expiration of tax non-capital loss carryovers	1,601	1,198	—
Other	(1,691)	539	379
Total	$ 6,491	$ (2,565)	$ (262)

At December 31, 2012, we performed an analysis of our deferred income tax balances which resulted in immaterial adjustments. The category “Other” is primarily comprised of the true up to our deferred tax liability balance at December 31, 2012 (see Note 2).

The components of the net deferred income tax liability at December 31, 2012 and 2011 were as follows:

	2012	2011
	(in thousands)	
Current deferred tax assets		
Unrealized derivative loss	$ 782	$ 595
Receivables	70	601
Prepaid assets	38	—
Other	915	—
Other liabilities	—	1,292
Property and equipment	588	—
Total current deferred tax assets	2,393	2,488
Current deferred tax liabilities		
Foreign exchange loss	—	(22)
Receivables	(46)	—
Prepaid assets	(8)	—
Other liabilities	(20)	(567)
Inventories	—	225
Property and equipment	(424)	—
Total current deferred tax liabilities	(498)	(364)
Net current deferred tax assets	$ 1,895	$ 2,124
Non-current deferred tax assets		
Accrued liabilities and payables	$ 150	$ 53
Unrealized derivative loss	976	576
Inventories	152	150
Property and equipment	4,019	12,195
Non-capital loss	28,455	32,289
Total non-current deferred tax assets	33,752	45,263
Valuation allowance	(29,059)	(30,587)
Net non-current deferred tax assets	4,693	14,676
Non-current deferred tax liabilities		
Property and equipment	(21,176)	(30,184)
Total non-current deferred tax liabilities	(21,176)	(30,184)
Net non-current deferred tax liability	$(16,483)	$(15,508)

We have accumulated losses or resource-related deductions available for income tax purposes in Turkey, Romania, Bulgaria and the United States. No recognition has been given in these consolidated financial statements to the future benefits that may result from the utilization of losses for income tax purposes. As of December 31, 2012, we had non-capital tax losses in Turkey of approximately 135.0 million New Turkish Lira (approximately $75.7 million), which began expiring in 2011; non-capital tax losses in Romania of approximately 25.9 million Romanian New Leu (approximately $7.7 million), which began expiring in 2011; non-capital losses in Bulgaria of approximately 4.9 million Bulgarian Lev (approximately $3.3 million), which expire commencing in 2017; and non-capital tax losses in the United States of approximately $29.2 million, which began expiring in 2010. At December 31, 2012, we assessed the valuation allowance and determined that it is properly classified against non-current deferred tax assets.

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 2007 are no longer subject to examination. The Turkish Ministry of Finance has substantially completed a limited examination of the 2010 corporate income tax return for our Turkish branch of TEMI, for which we expect an unqualified opinion to be issued and the case to be closed without adjustment during 2013.

In connection with our acquisition of Amity and Petrogas in August 2010, at December 31, 2012 we recognized a liability of $6.3 million due to an uncertain tax position related to the transfer of Petrogas shares to Amity prior to the acquisition, comprised of taxes of $3.9 million and interest and penalties of $2.4 million. However, 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. Therefore, we have recorded a corresponding receivable for $6.3 million in other long-term assets.

As of December 31, 2012, 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.

14. Segment information

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

	Corporate	Romania	Turkey (in thousands)	Bulgaria	Total
For the year ended December 31, 2012					
Total revenues	$ —	$ —	$143,650	$ 258	$143,908
Production	71	98	17,328	307	17,804
Exploration, abandonment and impairment	—	285	39,708	—	39,993
Cost of purchased natural gas	—	—	7,694	—	7,694
Seismic and other exploration	231	73	4,726	10	5,040
General and administrative	10,748	234	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	11,080	690	118,830	2,803	133,403
Operating (loss) income	(11,080)	(690)	24,820	(2,545)	10,505
Interest and other expense	(1,890)	—	(6,450)	—	(8,340)
Interest and other income	301	7	2,110	—	2,418
Loss on commodity derivative contracts	—	—	(5,548)	—	(5,548)
Foreign exchange gain (loss)	183	(104)	1,054	(50)	1,083
Income (loss) before income taxes	(12,486)	(787)	15,986	(2,595)	118
Income tax provision	—	—	(6,491)	—	(6,491)
Net income (loss)	$(12,486)	$ (787)	$ 9,495	$ (2,595)	$ (6,373)
Total assets as of December 31, 2012	$ 14,825	$ 105	$339,752	$ 1,957	$356,639[(1)]
Goodwill as of December 31, 2012	$ —	$ —	$ 9,021	$ —	$ 9,021
Capital expenditures	$ —	$ —	$ 80,957	$ 867	$ 81,824
For the year ended December 31, 2011 (see Note 2)					
Total revenues	$ 66	$ —	$128,356	$ 483	$128,905
Production	322	37	17,484	632	18,475
Exploration, abandonment and impairment	—	2	37,008	23,942	60,952
Cost of purchased natural gas	—	—	2,645	—	2,645
Seismic and other exploration	1,022	779	9,657	84	11,542
Revaluation of contingent consideration	—	—	—	6,000	6,000
General and administrative	14,309	405	21,585	6	36,305
Depreciation, depletion and amortization	96	31	38,389	492	39,008
Accretion of asset retirement obligations	—	—	1,131	11	1,142
Total costs and expenses	15,749	1,254	127,899	31,167	176,069
Operating (loss) income	(15,683)	(1,254)	457	(30,684)	(47,164)
Interest and other (expense) income	(7,250)	466	(6,878)	(3)	(13,665)
Interest and other income	15	12	914	148	1,089
Loss on commodity derivative contracts	—	—	(8,426)	—	(8,426)
Foreign exchange gain (loss)	16	(39)	(11,740)	(210)	(11,973)
Loss before income taxes	(22,902)	(815)	(25,673)	(30,749)	(80,139)
Income tax benefit	—	—	2,565	—	2,565
Net loss	$(22,902)	$ (815)	$ (23,108)	$(30,749)	$ (77,574)
Total assets as of December 31, 2011	$ 2,835	$ 881	$313,754	$ 4,164	$321,634[(1)]
Goodwill as of December 31, 2011	$ —	$ —	$ 8,514	$ —	$ 8,514
Capital expenditures	$ —	$ —	$117,071	$ 35,369	$152,440

	Corporate	Romania	Turkey (in thousands)	Bulgaria	Total
For the year ended December 31, 2010					
Total revenues	$ 182	$ —	$ 70,672	$ —	$ 70,854
Production	85	58	20,143	—	20,286
Exploration, abandonment and impairment	84	5,182	7,425	—	12,691
Seismic and other exploration	2,700	873	13,310	—	16,883
General and administrative	11,999	365	13,685	—	26,049
Depreciation, depletion and amortization	124	27	13,847	—	13,998
Accretion of asset retirement obligations	—	—	470	—	470
Total costs and expenses	14,992	6,505	68,880	—	90,377
Operating (loss) income	(14,810)	(6,505)	1,792	—	(19,523)
Interest and other expense	(4,596)	—	(2,459)	—	(7,055)
Interest and other income	103	2	162	—	267
Loss on commodity derivative contracts	—	—	(1,624)	—	(1,624)
Foreign exchange loss	(299)	(6)	(1,567)	—	(1,872)
Loss before income taxes	(19,602)	(6,509)	(3,696)	—	(29,807)
Provision for income taxes	—	—	262	—	262
Net loss	$(19,602)	$(6,509)	$ (3,434)	$ —	$ (29,545)
Total assets as of December 31, 2010	$ 44,038	$ 3,465	$299,086	$ —	$346,589[1]
Goodwill as of December 31, 2010	$ —	$ —	$ 10,341	$ —	$ 10,341
Capital expenditures	$ —	$ —	$170,317	$ —	$170,317

(1) Excludes assets from our discontinued Moroccan operations and oilfield services business of $1.6 million, $127.2 million, and $127.4 million at December 31, 2012, 2011 and 2010, respectively.

15. 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 Amended and Restated Credit Facility.

Foreign currency risk

We have underlying foreign currency exchange rate exposure. Our currency exposures relate to transactions denominated in the Canadian Dollar, Bulgarian Lev, European Union Euro, Romanian New Leu, Moroccan Dirham and New Turkish Lira. 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, 2012, we had 20.4 million New Turkish Lira (approximately $11.5 million) in cash and cash equivalents, which exposes us to exchange rate risk based on fluctuations in the value of the New Turkish Lira.

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, 2012 and 2011, 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 Turkiye Petrol Refinerileri A.Ş. ("TUPRAS"), a privately owned oil refinery in Turkey, 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, accounts payable and accrued liabilities were each estimated to have a fair value approximating the carrying amount at December 31, 2012 and 2011 due to the short maturity of those instruments. Indebtedness under the Amended and Restated Credit Facility was estimated to have a fair value approximating the carrying amount at December 31, 2012 and 2011 since the interest rate is generally market sensitive.

The financial assets and liabilities measured on a recurring basis at December 31, 2012 and 2011 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 speeds, 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, but generally accept the prices identified from the independent third-party.

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2012:

	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	$ —	$ (8,790)	$ —	$(8,790)
Total	$ —	$ (8,790)	$ —	$(8,790)

The following table summarizes the valuation of our financial assets and liabilities as of December 31, 2011:

	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	$ —	$ (7,071)	$ —	$(7,071)
Total	$ —	$ (7,071)	$ —	$(7,071)

16. Commitments

Our aggregate annual commitments, other than debt, as of December 31, 2012 were as follows:

		Payments Due by Year					
	Total	2013	2014	2015	2016	2017	Thereafter
				(in thousands)			
Leases and other	$9,160	$3,267	$1,415	$1,415	$436	$—	$ 2,627

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

We lease office space in Dallas, Texas, Bulgaria and Turkey. We also lease apartments in Turkey and Dallas, as well as operations yards in Turkey.

17. Contingency

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.

In the second quarter of 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. At December 31, 2012, we had a $1.0 million bank guarantee in place to ensure our performance of the Tselfat exploration permit work program. The Moroccan government drew down the bank guarantee in full on February 28, 2013. Although we plan to pursue a settlement with the Moroccan government for a lesser amount, we recorded $5.0 million in accrued liabilities relating to our Tselfat exploration permit during the second quarter of 2012 for this contractual obligation.

In the second quarter of 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 have recorded $2.0 million in general and administrative expense relating to our Aglen exploration permit during the second quarter of 2012 for this contractual obligation.

Pursuant to the purchase agreement with Direct, $10.0 million worth of our common shares would be due if we have not completed certain obligations regarding the drilling the Deventci-R2 well and the coring of the Etropole shale formation. A $10.0 million provision for this contingency was accrued at December 31, 2011, and we have included the expense in our consolidated statements of comprehensive income (loss) for the year ended December 31, 2011.

18. Related party transactions

Equity transactions

On September 1, 2010, we issued 7,300,000 common share purchase warrants to Dalea pursuant to the Dalea Credit Agreement. The common share purchase warrants are exercisable until September 1, 2013 and have an exercise price of $6.00 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, 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, 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.

On December 15, 2009, Viking International entered into an Agreement for Management Services (“Management Services Agreement”) with Viking Drilling. Pursuant to the Management Services Agreement, which was amended on August 5, 2010, Viking International agreed to provide management, marketing, storage and personnel services (collectively, the “Rig Services”) from time to time as requested by Viking Drilling for the operation of certain rigs owned by Viking Drilling that are located in Turkey. This agreement was terminated on June 13, 2012 due to the sale of our oilfield services business.

On June 1, 2010, Viking International entered into a lease agreement under which it leased space for storage, maintenance, and staging of material and equipment for oilfield services and services related to oil and natural gas drilling, exploration, development, geological or geophysical activities or oilfield infrastructure at premises owned by Gundem. This agreement was terminated on June 13, 2012 due to the sale of our oilfield services business.

On August 5, 2010, Viking International entered into an Agreement for Management Services (“Maritas Services Agreement”) with Maritas A.S. (“Maritas”). Pursuant to the Maritas Services Agreement, Viking International agreed to provide management, marketing and personnel services (collectively, the “Maritas Rig Services”) from time to time as requested by Maritas for the operation of a drilling rig owned by MAANBE LLC and located in Iraq. MAANBE LLC is indirectly owned by Mr. Mitchell and his children. Mr. Mitchell indirectly owns 50% of Maritas. Under the terms of the Maritas Services Agreement, Maritas paid Viking International for all actual costs and expenses associated with the provision of the Maritas Rig Services. This agreement was terminated on June 13, 2012 due to the sale of our oilfield services business.

On September 28, 2010, Viking International entered into an Agreement for Management Services (the “VOS Services Agreement”) with Viking Petrol Sahasi Hizmetleri A.S. (“VOS”). VOS is indirectly owned by Mr. Mitchell. Pursuant to the VOS Services Agreement, Viking International agreed to provide management, marketing, storage and personnel services from time to time as requested by VOS for the operation of certain equipment owned by VOS that is located in Turkey. This agreement was terminated on June 13, 2012 due to the sale of our oilfield services business.

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 resort hotel owned by Gundem Turizm Yatirim ve Isletme A.S. (“Gundem”), a Turkish company controlled by Mr. Mitchell. Under the accommodation agreement, TEMI leases 6 rooms at the hotel and pays the New Turkish Lira equivalent of $6,000 per month.

On June 6, 2011, we granted a 1.0% overriding royalty interest to Marhat Marmara Borv Hatlari Ins. Muh. Taahh.san. Tic. Ltd. sti (“Marhat”). Mustafa Yavuz, our former chief operating officer, is a 0.1% owner of Marhat. For the year ended December 31, 2012, we paid $532,000 in overriding royalties to Marhat.

On June 13, 2012, we entered into separate master services agreements with each of Viking International, 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. 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 transition services agreement has a two-year term. Viking Management agreed to use commercially reasonable efforts to eliminate its need for such services as soon as practicable following the entry into the agreement.

For the years ended December 31, 2012 and 2011, we incurred capital and operating expenditures of $73.8 million and $26.2 million, respectively, related to our various related party agreements.

The following table summarizes related party accounts receivable and accounts payable as of December 31, 2012 and December 31, 2011:

	December 31, 2012	December 31, 2011
	(in thousands)	
Related party accounts receivable:		
Viking International master services agreement	$ 313	$ —
Dalea promissory note	106	—
Total related party accounts receivable	$ 419	$ —
Related party accounts payable:		
Viking International master services agreement	$ 15,467	$ —
Marhat	281	—
Riata Management Service Agreement	167	323
Total related party accounts payable	$ 15,915	$ 323

The following table summarizes related party accounts receivable held for sale and related party accounts payable held for sale as of December 31, 2012 and December 31, 2011:

	December 31, 2012	December 31, 2011
	(in thousands)	
Related party accounts receivable:		
Maritas Services Agreement	$ —	$ 251
VOS Services Agreement	—	116
Total related party accounts receivable held for sale	$ —	$ 367
Related party accounts payable:		
Management Services Agreement	$ —	$ 92
VOS Services Agreement	—	617
Gundem lease agreements	—	36
Total related party accounts payable held for sale	$ —	$ 745

19. Quarterly results of operations (unaudited)

The results of operations by quarter for the years ended December 31, 2012 and 2011 were as follows:

	Three Months Ended			
	March 31,	June 30,	September 30,	December 31, (2)
	(in thousands, except per share data)			
For the year ended December 31, 2012 (see Note 2):				
Revenues	$ 36,671	$ 34,428	$ 34,815	$ 37,994
Net income (loss)	(3,627)	25,106	6,994	(12,227)
Comprehensive income (loss)	9,736	26,247	10,140	(7,653)
Basic and diluted net income (loss) per common share (1)	$ 0.00	$ 0.02	$ 0.00	$ (0.04)
For the year ended December 31, 2011 (see Note 2):				
Revenues	$ 29,079	$ 31,521	$ 33,506	$ 34,799
Net loss	(21,492)	(21,300)	(6,412)	(71,739)
Comprehensive loss	(19,288)	(33,906)	(44,683)	(75,135)
Basic and diluted net loss per common share (1)	$ (0.03)	$ (0.01)	$ (0.01)	$ (0.16)

(1) The sum of the individual quarterly net loss amounts per share may not agree with year-to-date net 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.

(2) The fourth quarter of 2011 includes a $44.7 million impairment charge related to certain of our proved and unproved oil and natural gas properties.

During the second and third quarters of 2012, we identified and corrected errors that originated in prior periods consisting mainly of accrued liabilities that should have been recorded in prior periods, errors in foreign currency gain/loss remeasurement, inappropriate recognition of receivable balances and other minor corrections with immaterial impact to other miscellaneous accounts. We concluded that the errors were not material to any of the previously reported periods or to the periods in which the errors were corrected. The impact of correcting the errors resulted in a decrease to our net loss of $1.2 million and an increase to our comprehensive income of $0.2 million for the three months ended March 31, 2012. The impact of correcting the errors resulted in an increase to net income of $2.2 million and an increase to our comprehensive income of $3.0 million for the three months ended June 30, 2012.

During the fourth quarter of 2011, we identified an error related to our foreign exchange gain (loss) that originated in prior periods and concluded that the error was not material to any of the previously reported periods or to the period in which the error was corrected. The impact of the error resulted in an increase to our net loss of $5.1 million and a decrease to our comprehensive loss of $0.9 million for the three and nine months ended September 30, 2011. This immaterial error was corrected in our third quarter of 2011 results of operations.

During the fourth quarter of 2012, as explained in Note 2, we identified and corrected errors that originated in prior periods that were not material to the year ended December 31, 2012, or to previously reported interim periods. The impact of the errors resulted in a decrease in our net loss for the fourth quarter of 2012 of approximately $3.6 million, which includes the impact of errors relating to 2011 discussed in Note 2.

20. Discontinued operations

Discontinued operations in Morocco

On June 27, 2011, we decided to discontinue our operations in Morocco. We have transferred our oilfield services equipment from Morocco to Turkey and 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, 2012 and 2011.

The assets and liabilities held for sale at December 31, 2012 and 2011 were as follows:

	December 31, 2012	December 31, 2011 (See Note 2)
	(in thousands)	
Cash	$ 93	$ 1,185
Receivables, net	—	8,098
Property and equipment, net	—	114,523
Other assets	1,526	3,362
Total assets held for sale	$ 1,619	$ 127,168
Liabilities held for sale—related party	$ —	$ 3,677
Accrued expenses and other liabilities	8,416	22,187
Total liabilities held for sale	$ 8,416	$ 25,864

Our operating results from discontinued operations for the years ended December 31, 2012, 2011 and 2010 are summarized as follows:

	2012	2011 (in thousands)	2010
Total revenues	$ 19,956	$ 28,419	$ 14,709
Total costs and expenses	(24,682)	(70,265)	(55,162)
Total other (expense) income	(357)	2,732	983
Loss from discontinued operations before income taxes	(5,083)	(39,114)	(39,470)
Gain on disposal of discontinued operations	35,999	—	—
Income tax provision	(8,297)	(4,255)	(731)
Net income (loss) from discontinued operations	$ 22,619	$(43,369)	$(40,201)

21. Supplemental oil and natural gas reserves and standardized measure information (unaudited)

Oil and natural gas reserves

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 reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. We engaged DeGolyer & MacNaughton to prepare our reserves estimates comprising 100% of our estimated proved reserves (by volume) at December 31, 2012.

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.

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

The 12-month average prices of oil and natural gas for 2012, 2011 and 2010 used to estimate reserves are shown in the table below.

	12-Month Average Price	
	Oil	Gas
2012	$108.66	$8.74
2011	$108.00	$7.18
2010	$ 79.00	$7.77

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 reserve quantities

	Oil (Mbls)	Natural Gas (Mmcf)	Total (Mboe)
Total proved reserves			
December 31, 2009	10,426	7,339	11,649
Acquisitions	1	13,987	2,332
Extensions and discoveries	—	1,923	321
Revisions of previous estimates	3,199	883	3,346
Production	(690)	(1,707)	(975)
December 31, 2010	12,936	22,425	16,673
Acquisitions	1	5,620	938
Extensions and discoveries	33	468	111
Revisions of previous estimates	(864)	(10,633)	(2,636)
Production	(891)	(4,657)	(1,667)
December 31, 2011	11,215	13,223	13,419
Extensions and discoveries	1,794	3,055	2,303
Revisions of previous estimates	(2,559)	423	(2,489)
Production	(949)	(4,238)	(1,655)
December 31, 2012	9,501	12,463	11,578
Proved developed reserves			
December 31, 2010			
Proved developed producing	4,775	7,820	6,078
Proved developed non-producing	813	8,741	2,270
Total	5,588	16,561	8,348
December 31, 2011			
Proved developed producing	4,284	6,564	5,378
Proved developed non-producing	1,089	3,956	1,748
Total	5,373	10,520	7,126
December 31, 2012			
Proved developed producing	4,222	5,228	5,093
Proved developed non-producing	910	2,887	1,391
Total	5,132	8,115	6,484
Proved developed reserves			
As of December 31, 2010	5,588	16,561	8,348
As of December 31, 2011	5,373	10,520	7,126
As of December 31, 2012	5,132	8,115	6,484
Proved undeveloped reserves			
As of December 31, 2010	7,348	5,865	8,326
As of December 31, 2011	5,842	2,703	6,293
As of December 31, 2012	4,369	4,348	5,094

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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, 2012, 2011 and 2010 are shown in the table below.

	2012	2011	2010
		(in thousands)	
Future cash inflows	$1,141,233	$1,306,844	$1,197,740
Future production costs	(305,814)	(246,566)	(300,347)
Future development costs	(93,267)	(63,805)	(80,255)
Future income tax expense	(106,411)	(171,592)	(143,000)
Future net cash flows	635,741	824,881	674,138
10% annual discount for estimated timing of cash flows	(199,864)	(293,084)	(235,771)
Standardized measure of discounted future net cash flows related to proved reserves	$ 435,877	$ 531,797	$ 438,367

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, 2012, 2011 and 2010.

	2012	2011	2010
		(in thousands)	
Standardized measure, January 1,	$ 531,797	$ 438,367	$250,009
Net change in sales and transfer prices and in production (lifting) costs related to future production	(52,279)	244,980	53,003
Changes in future estimated development costs	(52,027)	(34,401)	(63,040)
Sales and transfers of oil and natural gas during the period	(151,746)	(108,915)	(50,033)
Net change due to extensions and discoveries	107,694	5,684	11,321
Net change due to purchases of minerals in place	—	48,017	79,478
Net change due to revisions in quantity estimates	(116,363)	(134,997)	121,101
Previously estimated development costs incurred during the period	50,810	54,943	29,659
Accretion of discount	64,584	52,254	31,249
Other	11,161	(15,604)	7,471
Net change in income taxes	42,246	(18,531)	(31,851)
Standardized measure, December 31,	$ 435,877	$ 531,797	$438,367

Capitalized costs related to oil and natural gas producing activities

Our capitalized costs for oil and natural gas properties consisted of the following:

	Turkey	Other	Total
		(in thousands)	
As of December 31, 2012			
Oil and natural gas properties			
Proved	$229,462	$2,036	$231,498
Unproved	68,938	—	68,938
Total oil and natural gas properties	298,400	2,036	300,436
Less accumulated depletion	(73,589)	(510)	(74,099)
Net oil and natural gas properties capitalized costs	$224,811	$1,526	$226,337
As of December 31, 2011			
Oil and natural gas properties			
Proved	$172,917	$1,691	$174,608
Unproved	70,393	—	70,393
Total oil and natural gas properties	243,310	1,691	245,001
Less accumulated depletion	(44,870)	(457)	(45,327)
Net oil and natural gas properties capitalized costs	$198,440	$1,234	$199,674
As of December 31, 2010			
Oil and natural gas properties			
Proved	$150,407	$ —	$150,407
Unproved	73,662	6,505	80,167
Total oil and natural gas properties	224,069	6,505	230,574
Less accumulated depletion	(14,360)	—	(14,360)
Net oil and natural gas properties capitalized costs	$209,709	$6,505	$216,214

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, 2012, 2011 and 2010 are summarized as follows:

	Turkey	Other (in thousands)	Total
For the year ended December 31, 2012			
Acquisitions of properties			
Proved	$ —	$ —	$ —
Unproved	—	—	—
Exploration	36,465	—	36,465
Development	43,824	867	44,691
Total costs incurred	$ 80,289	$ 867	$ 81,156
For the year ended December 31, 2011			
Acquisitions of properties			
Proved	$ 14,526	$ 1,200	$ 15,726
Unproved	16,131	25,840	41,971
Exploration	22,534	—	22,534
Development	52,711	192	52,903
Total costs incurred	$105,902	$27,232	$133,134
For the year ended December 31, 2010			
Acquisitions of properties			
Proved	$ 53,997	$ —	$ 53,997
Unproved	49,017	—	49,017
Exploration	31,452	28,377	59,829
Development	37,198	—	37,198
Total costs incurred	$171,664	$28,377	$200,041

Results of operations for oil and natural gas producing activities (unaudited)

Our results of operations from oil and natural gas producing activities for each of the years ended December 31, 2012, 2011 and 2010 are shown in the following table:

	Turkey	Other (in thousands)	Total
For the year ended December 31, 2012			
Revenues	$133,930	$ 183	$134,113
Expenses:			
Production costs	17,328	476	17,804
Exploration, abandonment and impairment	39,708	285	39,993
Seismic and other exploration	4,726	314	5,040
Depreciation, depletion and amortization expenses	28,092	123	28,215
Total expenses	89,854	1,198	91,052
Income (loss) before income taxes	44,076	(1,015)	43,061
Income tax provision	(6,491)	—	(6,491)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 37,585	$ (1,015)	$ 36,570
For the year ended December 31, 2011			
Revenues	$123,672	$ 490	$124,162
Expenses:			
Production costs	17,484	991	18,475
Exploration, abandonment and impairment	37,008	23,944	60,952
Seismic and other exploration	9,657	1,885	11,542
Depreciation, depletion and amortization expenses	38,389	619	39,008
Total expenses	102,538	27,439	129,977
Income (loss) before income taxes	21,134	(26,949)	(5,815)
Income tax benefit	2,565	—	2,565
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 23,699	$(26,949)	$ (3,250)
For the year ended December 31, 2010			
Revenues	$ 69,657	$ 182	$ 69,839
Expenses:			
Production costs	20,201	85	20,286
Exploration, abandonment and impairment	7,425	5,266	12,691
Seismic and other exploration	14,298	2,585	16,883
Depreciation, depletion and amortization expenses	13,859	139	13,998
Total expenses	55,783	8,075	63,858
Income (loss) before income taxes	13,874	(7,893)	5,981
Income tax benefit	1,104	—	1,104
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 14,978	$ (7,893)	$ 7,085

Exhibit 10.22

AMENDMENT NO. 3 TO CREDIT AGREEMENT

This AMENDMENT NO. 3 TO CREDIT AGREEMENT (this ***"Amendment"***) is entered into as of November 21, 2012, by and among (1) AMITY OIL INTERNATIONAL PTY LTD, a company organized and existing under the laws of Australia (***"Amity"***); (2) DMLP, LTD., a Bahamas international business company (***"DMLP"***); (3) PETROGAS PETROL GAZ VE PETROKIMYA ÜRÜNLERI İNŞAAT SANAYI VE TICARET A.Ş., a Turkish joint stock company (***"Petrogas"***); (4) TALON EXPLORATION, LTD., a Bahamas international business company (***"Talon"***); (5) TRANSATLANTIC EXPLORATION MEDITERRANEAN INTERNATIONAL PTY. LTD., an Australian proprietary company (***"TEMI"***); (6) TRANSATLANTIC TURKEY, LTD., a Bahamas international business company (***"TT"*** , and, together with Amity, DMLP, Petrogas, Talon and TEMI, the ***"Borrowers"***); (7) TRANSATLANTIC PETROLEUM LTD., a Bermuda exempted company with limited liability (the ***"Parent"***); (8) TRANSATLANTIC PETROLEUM (USA) CORP., a Delaware corporation (***"TP USA"***); (9) TRANSATLANTIC WORLDWIDE, LTD., a Bahamas corporation (***"TW"*** , and, together with the Parent and TP USA, the ***"Initial Guarantors"***); (10) each of the lenders party hereto from time to time (the ***"Lenders"***); and (11) STANDARD BANK PLC, as administrative agent (in such capacity, the ***"Administrative Agent"***), as collateral agent (in such capacity, the ***"Collateral Agent"***) and as technical agent (in such capacity, the ***" Technical Agent "***).

W I T N E S S E T H:

WHEREAS, the Initial Guarantors, the Borrowers, the Lenders, the Agents and the LC Issuer are parties to that certain Amended and Restated Credit Agreement, dated as of May 18, 2011 (as amended, pursuant to Amendment No. 1 to Credit Agreement, dated as of August 4, 2011, and as further amended pursuant to Amendment No. 2 to Credit Agreement, dated as of September 14, 2011, the ***"Credit Agreement"***).

WHEREAS, the Borrowers desire that certain provisions of the Credit Agreement be amended and compliance with certain provisions of the Credit Agreement be waived, and the Administrative Agent and the Lenders party hereto are willing to agree to such amendments and waivers on the terms and subject to the conditions set forth herein.

NOW, THEREFORE, in consideration of the premises and mutual covenants herein and for other good and valuable consideration, the receipt and sufficiency of which is acknowledged, the parties hereto agree as follows:

SECTION 1. DEFINITIONS AND INTERPRETATION

1.1 Definitions . Unless the context otherwise requires, capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement.

1.2 Interpretation . This Amendment shall be construed and interpreted in accordance with the rules of construction set forth in Section 1 of the Credit Agreement.

SECTION 2. AMENDMENT

Subject to the conditions precedent set forth in Section 5 , the Credit Agreement shall be amended as follows:

2.1 Amended and Restated Defined Terms . Section 1.1 of the Credit Agreement shall be amended by amending and restating the defined terms " **Commitment Fee Rate** ", **"Commitment Reduction Amount"** and " **Commitment Reduction Date** " in their entirety as follows:

"" **Commitment Fee Rate** " means, at any time:

(a) 2.20% *per annum* multiplied by an amount equal to the unused and uncancelled portion of the aggregate Commitments which is less than or equal to the Maximum Available Amount (and is available to be borrowed at such time); and

(b) 1.10% *per annum* multiplied by an amount equal to the unused and uncancelled portion of the aggregate Commitments (if any) that exceeds the Maximum Available Amount (and is not available to be borrowed at such time)."

"" **Commitment Reduction Amount** " means, on each Commitment Reduction Date occurring in each month set forth below, the amount set forth opposite such month:

End of Period	Commitment Amount
December 2013	$ 67,500,000
March 2014	$ 60,000,000
June 2014	$ 52,000,000
September 2014	$ 45,000,000
December 2014	$ 37,500,000
March 2015	$ 30,000,000
June 2015	$ 22,500,000
September 2015	$ 15,000,000
December 2015	$ 7,500,000
March 2016	$ 0

““ **Commitment Reduction Date** ” means:

(a) the last day of each Fiscal Quarter, commencing with December 31, 2013; and

(b) the Maturity Date;

provided that if any Commitment Reduction Date would otherwise fall on a day that is not a Business Day, such Commitment Reduction Date shall instead occur on the preceding Business Day.”

2.2 Amended Defined Terms . Section 1.1 of the Credit Agreement shall be amended by deleting clause (i) of the defined term “Turkish Security Documents” in its entirety and replacing it with the following:

“(i) in accordance with **Section 7.12(e)** , a pledge agreement in respect of all of the rights of the Borrowers under their Hydrocarbon Licenses in Turkey that are Borrowing Base Assets;”

2.3 Mandatory Commitment Reduction . Section 2.6(b) of the Credit Agreement shall be amended and restated in its entirety as follows:

“(b) **Mandatory.** Notwithstanding anything to the contrary herein, on each Commitment Reduction Date, the aggregate Commitments of all Lenders then in effect shall be permanently reduced to an amount equal to the Commitment Reduction Amount in respect of such Commitment Reduction Date (or, if the amount of the aggregate Commitments at such time is less than the Commitment Reduction Amount, an amount equal to such Commitments). Each such reduction shall be applied to each Lender’s Commitment in accordance with its Pro Rata Share at such time, and shall take effect without any further action on the part of such Lender, any Borrower, any Obligor, any Secured Party or any other Person.”

2.4 Annual Financial Statements . Section 7.1(a) of the Credit Agreement shall be amended and restated in its entirety as follows:

“(a) **Annual Financial Statements** . The Borrowers shall deliver to the Administrative Agent (with sufficient copies for each Lender) a copy of (i) the audited consolidated balance sheet of the Parent and the related audited consolidated statements of income and of cash flows for each Fiscal Year as soon as available, but in any event within one hundred and five (105) days after the end of the Fiscal Year ending December 31, 2010 and within ninety (90) days after the end of each other Fiscal Year, and (ii) the unaudited Combined balance sheet of the Borrowers (which shall include their Subsidiaries) as at the end of each Fiscal Year and the related unaudited Combined statements of income and of cash flows for such Fiscal Year as soon as available, but in any event within one hundred and sixty five (165) days after the end of the Fiscal Year ending December 31, 2010 and within one hundred and twenty (120) days after the end of each other Fiscal Year, in the case of (i) setting forth in comparative form the figures for the previous Fiscal Year, reported on without a going concern or like qualification or exception, or qualification arising out of the scope of the audit, by KPMG LLP or another "Big Four" US firm of independent certified public accountants otherwise reasonably acceptable to the Administrative Agent, and in the case of (ii) setting forth in comparative form the figures for the previous Fiscal Year, certified by a Responsible Officer of the Borrowers as fairly stated in all material respects, and reviewed by KPMG LLP or such other "Big Four" US firm of independent certified public accountants otherwise reasonably acceptable to the Administrative Agent."

2.5 Additional Collateral . Section 7.12(e) of the Credit Agreement shall be amended and restated in its entirety as follows:

"(e) **Turkish Hydrocarbon Licenses** . If, due to either a change in market practice or GDPA practice or policy or the introduction of or any change in or in the interpretation of any Applicable Law or guidelines or requests of the GDPA after the Closing Date, the GDPA accepts for registration pledge agreements in respect of the rights of debtors under hydrocarbon licenses, the Borrowers shall within sixty (60) days after such change (or such later date as the Collateral Agent may agree to in writing) execute a Turkish Security Document in respect of their Hydrocarbon Licenses in Turkey that are Borrowing Base Assets. The Borrowers shall promptly submit such Turkish Security Document for registration with the GDPA and shall provide the Collateral Agent with written evidence from the GDPA that such Turkish Security Document has been submitted for registration with the GDPA."

2.6 Investments . Section 8.7(g) of the Credit Agreement shall be amended and restated in its entirety as follows"

" **(g)** loans to the Parent or TW made by any Borrower from such Borrower's Residual Excess Cash, *provided that* (i) the Majority Lenders shall be reasonably satisfied, based on the most recent Banking Case delivered under **ARTICLE 3** , that such Borrower will have sufficient working capital to fund its operations and meet the development plan (in each case, as forecast in such Banking Case) for the twelve (12) month period after the extension of any such loan, (ii) all rights of such Borrower in respect of any such loan are subject to a Security Interest and (ii) no Default or Event of Default has occurred and is continuing, or could reasonably be expected to occur as a result of, the making of any such loan."

2.7 Indemnified Matters . Section 11.10 of the Credit Agreement shall be amended and restated in its entirety as follows:

" **11.10 Indemnified Matters** . Notwithstanding anything to the contrary in this Agreement, the Agents may not include as part of any amount payable to it under **Section 11.9** , **Section 12.5,** and/or **Section 12.6** , a sum representing the cost to such Agent in terms of management time and other resources calculated on the basis of daily or hourly rates."

SECTION 3. NO AMENDMENT FEE

Each of the Agents and the Lenders party hereto (being Lenders constituting the Majority Lenders) agrees, and the Administrative Agent hereby acknowledges such agreement, that the Borrowers shall not be required to pay any fee to any Agent or any Lender solely as consideration for entering into this Amendment.

SECTION 4. AFFIRMATION

The Initial Guarantors hereby consent and agree to and acknowledge and affirm the terms of this Amendment. The Initial Guarantors hereby further agree that their respective guarantee obligations under Article 10 of the Credit Agreement shall remain in full force and effect and be unaffected hereby.

SECTION 5. CONDITIONS PRECEDENT

The amendments referred to in Section 2 shall become effective if this Amendment shall have been executed by the Initial Guarantors, the Borrowers, the Lenders and the Administrative Agent and counterparts hereof as so executed shall have been delivered to the Administrative Agent.

SECTION 6. MISCELLANEOUS

6.1 Representations and Warranties . Each Obligor, by signing below, hereby represents and warrants to the Agents, the LC Issuer, and the Lenders as follows:

(a) it is duly organized, validly existing and in good standing (if such concept exists under the laws of its jurisdiction of organization) under the laws of its jurisdiction of organization;

(b) the execution, delivery, and performance of this Amendment and the consummation of the transactions contemplated hereby (i) are within its corporate powers, (ii) have been duly authorized by all necessary corporate action, (iii) do not contravene its constitutional documents or any applicable law or any of its contractual obligations, and (iv) will not result in the creation or imposition of any Lien prohibited by the Credit Agreement;

(c) no consent, order, authorization, or approval or other action by, and no notice to or filing with, any Governmental Authority or any other Person is required for its due execution and delivery of this Amendment, the performance of its obligations hereunder or the consummation of the transactions contemplated hereby;

(d) it has duly executed and delivered this Amendment, and upon satisfaction of the conditions set forth in Section 5 above, this Amendment constitutes its legal, valid, and binding obligation, enforceable against it in accordance with its terms, except as such enforceability may be limited by any applicable bankruptcy, insolvency, reorganization, moratorium, or similar law affecting creditors' rights generally and by general principles of equity;

(e) both before and after giving effect to this Amendment, no Default or Event of Default has occurred and is continuing or would result from the consummation of the transactions contemplated by this Amendment; and

(f) to the extent not already made above, each of the other representations and warranties set forth in Article 6 of the Credit Agreement is true and correct in all material respects as of the date hereof (unless stated to relate solely to an earlier date, in which case such representation or warranty shall be true and correct in all material respects as of such earlier date).

6.2 Waiver of Claims. Each Obligor hereby waives and releases each of the Lenders, the LC Issuer and the Agents and their respective directors, officers, employees, attorneys, affiliates and subsidiaries from any and all claims, offsets, defenses and counterclaims of which it is aware that currently exist and can now be asserted to reduce or eliminate all or any part of the obligations of such Obligor to the Lenders, the LC Issuer and the Agents as provided in the Loan Documents, such waiver and release being made with full knowledge and understanding of the circumstances and effect thereof and after having consulted legal counsel with respect thereto.

6.3 Expenses. As provided in Section 11.10 and Section 12.5 of the Credit Agreement, but without limiting any terms or provisions thereof, each Obligor agrees to pay on demand, all reasonable costs and expenses incurred by the Agents in connection with the preparation, negotiation, and execution of this Amendment, including without limitation the reasonable costs and fees of the Agents' legal counsel, regardless of whether this Amendment becomes effective in accordance with the terms hereof.

6.4 Credit Agreement Unaffected. Each reference to the Credit Agreement herein or in any other Loan Document shall hereafter be construed as a reference to the Credit Agreement as amended hereby. Except as herein otherwise specifically provided, all provisions of the Credit Agreement and the other Loan Documents shall remain in full force and effect and be unaffected hereby. This Amendment is a Loan Document.

6.5 Entire Agreement. This Amendment, together with the Credit Agreement and the other Loan Documents, integrates all the terms and conditions mentioned herein and supersedes all oral representations and negotiations and prior writings with respect to the subject matter hereof.

6.6 Counterparts. This Amendment may be executed in any number of counterparts, by different parties hereto in separate counterparts and by facsimile signature, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same agreement.

6.7 Governing Law. THIS AMENDMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

6.8 Submission to Jurisdiction . EACH PARTY HEREBY IRREVOCABLY CONSENTS TO THE EXCLUSIVE JURISDICTION OF ANY UNITED STATES FEDERAL OR NEW YORK STATE COURT SITTING IN NEW YORK CITY, AND APPELLATE COURTS FROM ANY THEREOF, IN ANY LITIGATION OR OTHER PROCEEDING BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, ANY LOAN DOCUMENT, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF AN AGENT, A LENDER OR THE LC ISSUER OR AN OBLIGOR IN CONNECTION HEREWITH OR THEREWITH; PROVIDED , THAT NOTHING HEREIN SHALL LIMIT THE RIGHT OF AN AGENT, A LENDER OR THE LC ISSUER TO BRING PROCEEDINGS AGAINST AN OBLIGOR IN THE COURTS OF ANY OTHER JURISDICTION.

6.9 Jury Trial Waiver . THE PARTIES HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVE TO THE FULLEST EXTENT PERMITTED BY LAW ANY RIGHTS THEY MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS AMENDMENT, OR ANY COURSE OF CONDUCT, COURSE OF DEALING, STATEMENTS (WHETHER ORAL OR WRITTEN) OR ACTIONS OF THE PARTIES IN CONNECTION HEREWITH. EACH PARTY ACKNOWLEDGES AND AGREES THAT IT HAS RECEIVED FULL AND SUFFICIENT CONSIDERATION FOR THIS PROVISION AND THAT THIS PROVISION IS A MATERIAL INDUCEMENT FOR THE PARTIES TO ENTER INTO THIS AMENDMENT.

[Remainder of page left blank intentionally.]

IN WITNESS WHEREOF, this Amendment has been duly executed and delivered as of the date first written above.

AMITY OIL INTERNATIONAL PTY LTD. , as a Borrower

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Director

DMLP, LTD. , as a Borrower

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Vice President

PETROGAS PETROL GAZ VE PETROKIMYA ÜRÜNLERI İNŞAAT SANAYI VE TICARET A.Ş. , as a Borrower

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Director

TALON EXPLORATION, LTD. , as a Borrower

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Vice President

TRANSATLANTIC EXPLORATION MEDITERRANEAN INTERNATIONAL PTY. LTD. , as a Borrower

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Director

TRANSATLANTIC TURKEY, LTD. , as a Borrower

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Vice President

TRANSATLANTIC PETROLEUM LTD , as a Guarantor

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: Vice President

TRANSATLANTIC PETROLEUM (USA) CORP , as a Guarantor

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: President

TRANSATLANTIC WORLDWIDE, LTD. , as a Guarantor

By: /s/ Wil F. Saqueton
Name: Wil F. Saqueton
Title: President

STANDARD BANK PLC , as Administrative Agent

By: /s/ Ola Busari
Name: Ola Busari
Title: Senior Manager

By: /s/ Zakia Mannan
Name: Zakia Mannan
Title: Senior Manager

STANDARD BANK PLC , as Collateral Agent

By: /s/ Ola Busari
Name: Ola Busari
Title: Senior Manager

By: /s/ Zakia Mannan
Name: Zakia Mannan
Title: Senior Manager

STANDARD BANK PLC , as Technical Agent

By: /s/ Aurelie Tan
Name: Aurelie Tan
Title: Senior Manager

By: /s/ Alistair Reid
Name: Alistair Reid
Title: Senior Vice President

STANDARD BANK PLC , as a Lender

By: /s/ Aurelie Tan
Name: Aurelie Tan
Title: Senior Manager

By: /s/ Alistair Reid
Name: Alistair Reid
Title: Senior Vice President

BNP PARIBAS (SUISSE) SA , as a Lender

By: /s/ F.X. Reignier
Name: F.X. Reignier
Title: ______________________

By: /s/ Adrien Bouchet
Name: Adrien Bouchet
Title: ______________________

EXHIBIT 21.1

Subsidiaries of TransAtlantic Petroleum Ltd.
May 15, 2013

Subsidiary	Jurisdiction of Incorporation
Amity Oil International Pty Ltd	Australia
Incremental Petroleum Pty Ltd	Australia
TransAtlantic Australia Pty Ltd	Australia
TransAtlantic Exploration Mediterranean International Pty Ltd	Australia
TransAtlantic (Holdings) Australia Pty Ltd	Australia
Anschutz Morocco Corporation	Bahamas
Direct Petroleum Morocco, Inc.	Bahamas
DMLP, Ltd.	Bahamas
Talon Exploration, Ltd.	Bahamas
TransAtlantic Maroc, Ltd.	Bahamas
TransAtlantic Turkey, Ltd.	Bahamas
TransAtlantic Worldwide, Ltd.	Bahamas
TransAtlantic Holdings, Ltd.	Bahamas
Longe Energy Limited	Bermuda
Thrace Basin Natural Gas (Turkiye) Corporation	British Virgin Islands
Direct Petroleum Bulgaria EOOD	Bulgaria
TransAtlantic Petroleum Cyprus Limited	Cyprus
TransAtlantic Petroleum (USA) Corp.	Delaware
MOS Viking SARL	Morocco
TransAtlantic Worldwide Romania SRL	Romania
Petrogas Petrol Gaz ve Petrokemya Urunleri Insaat Sanayive Ticaret A.S.	Turkey

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
TransAtlantic Petroleum Ltd.:

We consent to the incorporation by reference in the registration statement (No. 333-162814) on Form S-8 of TransAtlantic Petroleum Ltd. (the "Company") of our reports dated May 15, 2013, with respect to the consolidated balance sheets of TransAtlantic Petroleum Ltd as of December 31, 2012, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for the year ended December 31, 2012, and all related financial statement schedules, and the effectiveness of internal control over financial reporting as of December 31, 2012, which reports appear in the December 31, 2012 annual report on Form 10-K of TransAtlantic Petroleum Ltd.

Our report dated May 15, 2013, on the effectiveness of internal control over financial reporting as of December 31, 2012, expresses an opinion that the Company did not maintain effective internal control over financial reporting as of December 31, 2012 because of the effect of material weaknesses on the achievement of the objectives of the control criteria and contains an explanatory paragraph that states that the following material weaknesses were identified and included in management's assessment in Item 9A of the Company's December 31, 2012 Annual Report on Form 10-K:

- The Company has not maintained a sufficient complement of qualified personnel with U.S. GAAP knowledge and expertise, which resulted in the ineffective design or operation of the Company's internal controls over significant account balances and estimates.
- The Company's management review and approval controls were not complete and comprehensive and not operating at a sufficient level of precision, to prevent or detect material misstatements in the Company's financial statements.
- The Company has not designed and implemented effective internal controls around the accounting for oil & gas properties.
- The Company has not designed and implemented effective internal controls over income tax provisions.
- The Company has not designed and implemented effective internal controls over significant non-routine transactions.
- The Company has not designed and implemented effective controls over remeasurement and translation of its foreign entity account balances.

KPMG LLP

/s/ KPMG LLP

Dallas, Texas
May 15, 2013

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TransAtlantic Petroleum Ltd.

We consent to the incorporation by reference in the Registration Statement on Form S-8 (File No. 333-162814) of TransAtlantic Petroleum Ltd. of our report dated March 23, 2012 (except for Note 2 dated May 15, 2013) on the consolidated balance sheet of TransAtlantic Petroleum Ltd. as at December 31, 2011, and the consolidated statements of comprehensive income (loss), equity and cash flows for each of the years in the two-year period ended December 31, 2011, which report appears in the Form 10-K of TransAtlantic Petroleum Ltd. for the year ended December 31, 2012.

/s/ KPMG LLP
Chartered Accountants

Calgary, Canada
May 15, 2013

Exhibit 23.3

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

May 14, 2013

TransAtlantic Petroleum Ltd.
16803 Dallas Parkway, Suite 200
Addison, Texas 75001

Ladies and Gentlemen:

We hereby consent to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm under the heading “Glossary of Selected Oil and Natural Gas Terms”, “Part I. – Item 1. Business” and “Part I – Item 2. Properties” of the Annual Report on Form 10-K for the year ended December 31, 2012, of TransAtlantic Petroleum Ltd. (“TransAtlantic”) to be filed with the U.S. Securities and Exchange Commission on or about May 14, 2013 (the “Annual Report”), including any amendments thereto, and to the inclusion of our third-party letter report dated February 28, 2013, containing our opinion on the proved, probable and possible reserves attributable to certain properties owned by TransAtlantic as of December 31, 2012.

We hereby further consent to the incorporation by reference of the foregoing in the Registration Statement on Form S-8 (No. 333-162814) of TransAtlantic.

Very truly yours,

/s/ DeGOLYER and MaCNAUGHTON

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATION

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

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

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

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

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

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

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

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

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

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

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

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

May 15, 2013

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

Exhibit 31.2

CERTIFICATION

I, Wil F. Saqueton, certify that:

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

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

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

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

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

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

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

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

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

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

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

May 15, 2013

/s/ WIL F. SAQUETON
Wil F. Saqueton
Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report on Form 10-K of TransAtlantic Petroleum Ltd. (the "Company") for the year ended December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, N. Malone Mitchell, 3rd, Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Dated: May 15, 2013

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

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

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

Exhibit 32.2

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

In connection with the Annual Report on Form 10-K of TransAtlantic Petroleum Ltd. (the "Company") for the year ended December 31, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Wil F. Saqueton, Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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

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

Dated: May 15, 2013

/s/ WIL F. SAQUETON
Wil F. Saqueton
Chief Financial Officer

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

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

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

This is a digital representation of a DeGolyer and MacNaughton report.

This file is intended to be a manifestation of certain data in the subject report and as such are subject to the same conditions thereof. The information and data contained in this file may be subject to misinterpretation; therefore, the signed and bound copy of this report should be considered the only authoritative source of such information.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

D E G OLYER AND M AC N AUGHTON
5001 S PRING V ALLEY R OAD
S UITE 800 E AST
D ALLAS , T EXAS 75244

February 28, 2013

TransAtlantic Petroleum Ltd.
16803 Dallas Parkway, Suite 200
Addison, Texas 75001

Gentlemen:

Pursuant to your request, we have conducted an independent evaluation, completed on February 28, 2013, to serve as a reserves audit of the extent and value of the proved, probable, and possible oil, natural gas, and condensate reserves, as of December 31, 2012, of certain properties owned by TransAtlantic Petroleum Ltd. (TransAtlantic) in Turkey and Bulgaria. TransAtlantic has represented that these properties account for 100 percent, on a net equivalent barrel basis, of TransAtlantic's net proved, probable, and possible reserves, as of December 31, 2012. The net proved, probable, and possible reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4-10(a) (l)-(32) of Regulation S-X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by TransAtlantic.

Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2012. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by TransAtlantic after deducting interests owned by others. Only net reserves are reported herein.

Gas reserves estimated herein are expressed as sales gas. Sales gas is defined as that portion of the total gas produced from the reservoir after reduction for shrinkage resulting from field separation, processing, fuel use, and flare available to be delivered into a gas pipeline for sale. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.70 pounds per square inch absolute (psia). Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation.

Values of proved, probable, and possible reserves shown herein are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves plus net profits (where applicable). Future net revenue is defined as the future gross revenue less direct operating expenses, capital costs, abandonment costs, and net profits, where applicable. Direct operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization.

Estimates of oil, natural gas, and condensate reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with TransAtlantic personnel, from TransAtlantic files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by TransAtlantic with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves

Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. In such case, an analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

The fields have been grouped into three asset groups based on economic considerations: the Thrace Basin Natural Gas Company (TBNGC) asset group, the TransAtlantic core (TAT) asset group, and the Edirne asset group (composed of Edirne field). All fields are subject to a royalty of 12.5 percent. The TBNGC asset group is subject to an additional 1.0-percent overriding royalty interest, except for Alibey field which has a 0.5-percent overriding royalty interest. Certain wells are also subject to a net profits interest of 5 percent. Net reserves quantities reported herein reflect the appropriate quantity reductions for royalty interests and overriding royalty interests, as well as the quantity reduction yielded from the calculated revenue associated with the net profits payable.

Definition of Reserves

Petroleum reserves included in this report are classified by degree of proof as proved, probable, or possible. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (l)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

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

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

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

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Probable reserves – Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) 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.

(ii) 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.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (iv) and (vi) of the definition of possible reserves.

Possible reserves – Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) 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.

(ii) 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.

(iii) 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.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) 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.

(vi) Pursuant to paragraph (iii) of the proved oil and gas reserves definition, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed oil and gas reserves – Developed oil and 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 if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are 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.

(i) 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.

(ii) 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.

(iii) 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, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The extent to which probable and possible reserves ultimately may be reclassified as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Probable and possible reserves in this report have not been adjusted in consideration of these additional risks and therefore are not comparable with proved reserves.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil, Condensate, and Natural Gas Prices

Prices used in this evaluation were based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. An average reference oil price during this period is Brent at 111.07 United States dollars (U.S.$) per barrel. The average oil and condensate prices used to estimate reserves herein were as follows: U.S.$83.73 per barrel for TBNGC asset group, U.S.$47.72 per barrel in Bulgaria, U.S.$103.93 per barrel in AG field, U.S.$111.27 per barrel in Arpatepe field, U.S.$102.25 per barrel in Goksu and Molla fields, and U.S.$109.96 per barrel in Selmo field. The overall weighted-average oil price in this report was U.S.$108.30. An average reference gas price during this period is the United Kingdom National Balancing Point Index of U.S.$9.50 per million British thermal unit. The average gas prices used in this report were as follows: U.S.$9.35 per thousand cubic feet for TBNGC asset group, U.S.$8.56 per thousand cubic feet for the Edirne asset group, U.S.$4.22 per thousand cubic feet for Bulgaria, U.S.$8.09 per thousand cubic feet for Bakuk field, U.S.$8.61 per thousand cubic feet for CAB field, and U.S.$8.56 per thousand cubic feet for the remaining fields in TAT asset group. The overall weighted-average gas price in this report was U.S.$8.94. These prices were held constant for the lives of the properties.

Net Profits Interest

As represented by TransAtlantic, there is a 5-percent net profits interest burden for certain wells in the AG, Alpullu, CAB, DAK, Edirne, Karapurcek, Pancarkoy, and REDY fields. Where applicable, the net profits reduced TransAtlantic's ownership of reserves and revenue values.

Operating Expenses and Capital Costs

Estimates of operating expenses based on current expenses were used for the lives of the properties with no increases in the future based on inflation. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changes in operating conditions. Future capital expenditures were estimated using current values and were not adjusted for inflation.

Abandonment Costs

Abandonment costs were provided by TransAtlantic. These costs were estimated using current values and were not adjusted for inflation.

Royalty and Taxes

All fields are subject to a royalty of 12.5 percent. Fields in the TBNGC asset group are subject to an additional 1.0-percent overriding royalty interest, except for Alibey field which has an 0.5-percent overriding royalty interest. TransAtlantic has represented that there are no production taxes to be paid in Turkey or Bulgaria. No other taxes, including income taxes for Turkey, Bulgaria, Canada, or the United States, were considered in this evaluation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2012, oil, condensate, and gas volumes estimated herein. The reserves estimated in this report can be produced under current regulatory guidelines.

Summary of Oil and Gas Reserves and Revenue

The estimates of net proved, probable, and possible reserves, as of December 31, 2012, attributable to the interests owned by TransAtlantic, of the properties evaluated herein, are summarized as follows, expressed in barrels (bbl) or thousands of cubic feet (10^3 ft ^{3}):

	Estimated by DeGolyer and MacNaughton as of December 31, 2012		
	Net Oil (bbl)	Net Condensate (bbl)	Net Sales Gas (10^3 ft ^{3})
Proved			
Developed	5,131,503	0	8,115,152
Undeveloped	4,369,421	0	4,348,059
Total Proved	**9,500,924**	**0**	**12,463,211**
Probable	7,948,483	0	12,144,935
Possible	15,232,518	0	104,247,123

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

The estimated revenue and expenditures attributable to TransAtlantic's interests in the proved, probable, and possible net reserves, as of December 31, 2012, of the properties appraised under the aforementioned assumptions concerning future prices and costs are summarized as follows, expressed in U.S. dollars (U.S.$):

	Estimated by DeGolyer and MacNaughton as of December 31, 2012				
	Proved				
	Developed (U.S.$)	Undeveloped (U.S.$)	Total (U.S.$)	Probable (U.S.$)	Possible (U.S.$)
Future Gross Revenue	628,475,886	512,757,099	1,141,232,985	956,572,722	2,601,278,122
Production Taxes	0	0	0	0	0
Operating Expenses	177,440,923	115,562,243	293,003,166	122,845,603	371,095,227
Capital Costs	4,499,828	88,767,655	93,267,483	133,440,539	226,396,600
Abandonment Costs	9,822,288	1,851,401	11,673,689	2,936,667	3,596,600
Net Profits	129,952	1,006,899	1,136,851	1,014,981	40,078,945
Future Net Revenue	436,582,895	305,568,901	742,151,796	696,334,932	1,960,110,750
Present Worth at 10 Percent	309,012,592	202,065,527	511,078,119	451,102,919	1,080,171,472

Notes:
1. Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.
2. Future income tax expenses were not taken into account in the preparation of these estimates.

In our opinion, the information relating to estimated proved, probable, and possible reserves, estimated future net revenue from proved, probable, and possible reserves, and present worth of estimated future net revenue from proved, probable, and possible reserves of oil, condensate, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10 (a) (1)–(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (5), (8), and 1203(a) of Regulation S-K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

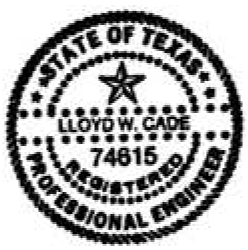
To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in TransAtlantic. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of TransAtlantic. DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716



Lloyd W. Cade, P.E.

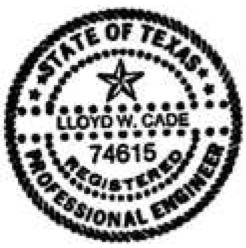
Lloyd W. Cade, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Lloyd W. Cade, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to TransAtlantic dated February 28, 2013, and that I, as Senior Vice President, was responsible for the preparation of this report.
2. That I attended Kansas State University, and that I graduated with a Bachelor of Science degree in Mechanical Engineering in the year 1982; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers; and that I have in excess of 30 years of experience in oil and gas reservoir studies and evaluations.
3. That DeGolyer and MacNaughton or its officers have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of TransAtlantic Petroleum Ltd. or affiliate thereof.

SIGNED: February 28, 2013



Lloyd W. Cade, P.E.

Lloyd W. Cade, P.E.
Senior Vice President
DeGolyer and MacNaughton