valeura energy inc.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2016

Dated March 14, 2017

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ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the following abbreviations have the meanings set forth below.

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbl/d	barrel per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day

Other

boe	barrel of oil equivalent on the basis of one boe to six thousand cubic feet of gas. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
boe/d	barrel of oil equivalent per day.
BOTAS	Boru Hatlari ile Petrol Tasima Anonim Sirketi ("**BOTAS**") owns and operates the national crude oil pipeline grid and the national gas pipeline grid in Turkey. BOTAS regularly posts natural gas prices and its Industrial Interruptible Tariff benchmark is shown herein as a reference price.
M$	thousands of dollars.
MM$	millions of dollars.
Mcfe	thousand cubic feet of sales gas equivalent derived by converting oil to gas in the ratio of one barrel of oil to six thousand cubic feet of gas. Mcfes may be misleading, particularly if used in isolation. A Mcfe conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
NYMEX	New York Mercantile Exchange.
TL/m^3	Turkish Lira per cubic metre.
TL	Turkish Lira.
$	Canadian dollars.
US$	U.S. dollars.
IP	initial on-stream production rate.

Conversions

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units)

To convert from	To	Multiply by
1,000 cubic metres of gas	Mcf	35.494
bbl	cubic metres of oil	0.158
cubic metres of oil	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

DEFINITIONS

In this Annual Information Form, the following words and phrases have the meanings set forth below, unless otherwise indicated.

"**abandonment and reclamation costs**" means all costs associated with the process of restoring a reporting issuer's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"**Acquisition Agreement**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**Arrangement**" means the plan of arrangement involving PanWestern and Northern Hunter under the provisions of Section 193 of the ABCA, completed on April 9, 2010.

"**Barnali Farm-in**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**Barnali Licenses**" means, collectively, the exploration licenses in quadrants F18-c1, F18-c2, F18-c3, F18-c4, and F19-d1, F19-d4 held by CRBV.

"**Board**" means the board of directors of Valeura Energy Inc.

"**BOTAS Reference Price**" has the meaning set forth under the heading "*Risk Factors – Pricing and Marketing*".

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares in the capital of the Company.

"**Company**" or "**Valeura**" means Valeura Energy Inc. and, where applicable, includes its subsidiaries and affiliates.

"**CRBV**" means Corporate Resources B.V., a wholly-owned affiliate of Valeura.

"**crude oil**" or "**oil**" as described in the COGE Handbook means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

"**D&M**" means DeGolyer and MacNaughton, independent petroleum engineering consultants.

"**D&M Reserves Report**" means the independent engineering evaluation of the oil and natural gas reserves attributable to the properties of Valeura in Turkey prepared by D&M with a preparation date of March 14, 2017 and effective December 31, 2016.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying and acquiring well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Deep Rights Sale Agreement**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**Definitive Agreements**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Edirne Leases**" has the meaning set forth under the heading "*Description of the Business and Operations – Edirne Leases*".

"**EMRA**" means the Republic of Turkey's Energy Markets Regulatory Authority.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**frac**" means hydraulic fracturing whereby fractures are propagated in an underground rock layer by injecting fluids, typically mixtures of sand and water, under high pressures.

"**field**" means a defined geographical area consisting of one or more hydrocarbon pools.

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs.

"**GDPA**" means the Republic of Turkey's General Directorate of Petroleum Affairs.

"**gross**" means:

(a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**ICFR**" has the meaning set forth under the heading "*Description of Capital Structure-Internal Controls Over Financial Reporting*".

"**Initial TBNG Acquisition**" has the meaning set forth under the heading "*General Development of the Business*".

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"**net**" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**New Petroleum Law**" means Turkey's Petroleum Law No. 6491 adopted in 2013 which replaced the Old Petroleum Law.

"**NI 51-101**" means National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities.*

"**Northern Hunter**" means Northern Hunter Energy Inc.

"**Old Petroleum Law**" means Turkey's Petroleum Law No. 6326 adopted in 1954 which was replaced by the New Petroleum Law.

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**Option**" means an option to acquire a Common Share pursuant to the Stock Option Plan.

"**PanWestern**" means PanWestern Energy Inc.

"**PKK**" means the Kurdistan Workers' Party, which is a Kurdish organization listed as a terrorist organization by the UN and NATO, fighting an armed struggle with the Turkish state for an autonomous Kurdistan and cultural and political rights for the Kurds in Turkey.

"**Preferred Shares**" has the meaning set forth under the heading "*Description of Capital Structure*".

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**PTI**" means Pinnacle Turkey, Inc.

"**reservoir**" as described in the COGE Handbook means a subsurface rock unit that contains an accumulation of petroleum.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**Shareholders**" means the holders of Common Shares and "**Shareholder**" means any one of them.

"**solution gas**" means gas dissolved in crude oil.

"**South Thrace lands**" means, collectively, the production leases in quadrants F18-c4-2, F18-c3-1, F19-d4-1, F19-d4-2, F19-d3-1, F19-c3-1, G18-b1-1, G18-b2-1, G19-a1-1 and production lease numbers 3860 and 3861 held by the TBNG JV.

"**Statoil**" means Statoil Banarli Turkey B.V., a wholly-owned affiliate of Statoil ASA.

"**Stock Option Plan**" means the stock option plan of the Company.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as:

(a) "exploratory type" if not drilled into a proved property; or

(b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated November 3, 2016 among the Company, Cormark Securities Inc. and Computershare Trust Company of Canada, as escrow agent, governing the terms and conditions of the Subscription Receipts.

"**Subscription Receipts**" means the subscription receipts of the Company that were issued pursuant to the Offering and the Subscription Receipt Agreement.

"**Subsequent Deep Rights Sale Agreement**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**Subsequent West Thrace Deep Rights Sale**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**TBNG**" means Thrace Basin Natural Gas Turkiye Corporation, a wholly-owned affiliate of TWL prior to completion of the TBNG Acquisition and thereafter, a wholly-owned affiliate of Valeura.

"**TBNG JV**" means the joint venture formed between CRBV, TBNG and PTI resulting from the successful closing of the Initial TBNG Acquisition.

"**TBNG-PTI Offer**" means the conditional offer executed by Valeura and TWL on February 9, 2011 to jointly acquire certain non-operated producing natural gas assets and lands in the Thrace Basin and other interests in exploration lands in the Anatolian Basin from TBNG and PTI.

"**TPAO**" means Turkiye Petrolleri Anonim Ortakligi.

"**TransAtlantic**" means TransAtlantic Petroleum Ltd.

"**TWL**" means TransAtlantic Worldwide, Ltd., a wholly-owned affiliate of TransAtlantic.

"**TSX**" means the Toronto Stock Exchange.

"**U.S.**" or "**United States**" means the United States of America, its territories and possessions, any state of the United States, and the District of Columbia.

"**VENBV**" means Valeura Energy (Netherlands) B.V., a wholly-owned affiliate of Valeura.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. These costs do not include costs of abandoning the gathering system or reclaiming the wellsite.

"**West Thrace Deep Rights Sale**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**West Thrace lands**" means, collectively, the exploration licences in quadrants F17-c2, F17-c3, F18-d1, F18-d2 and F18-d4 and production lease numbers 2926, 3659 and 5122 held by the TBNG JV.

RESERVES DEFINITIONS

Reserves

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"**possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

There is a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

"**developed**" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

"**developed producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**developed non-producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Short Production Test Rates

Any short production test rates disclosed in this Annual Information Form are preliminary in nature and may not be indicative of stabilized on-stream production rates. Initial on-stream production rates are typically disclosed with reference to the number of days in which production is measured (e.g., IP30 refers to an initial on-stream production rate measured over a 30 day period). Initial on-stream production rates are not necessarily indicative of long-term performance or ultimate recovery. To date, shallow gas conventional wells and fraced unconventional tight gas wells have exhibited relatively high decline rates at more than 50% and 75%, respectively, in their first year of production. All natural gas rates and volumes are presented net of any load fluids.

FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information (collectively, "**forward-looking statements**") under applicable securities legislation. Such forward-looking statements are included for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such forward-looking statements may not be appropriate for other purposes, such as making investment decisions. Forward-looking statements typically include words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "target", "goal", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to:

- the Company's growth strategy;
- anticipated work programs, budgets and operational plans (seismic, drilling, fracing, completions and workovers) and associated capital expenditures on the Banarli Licences and TBNG JV lands and the funding thereof;
- the prospectivity of the Banarli Licences and the TBNG JV lands, including the extent of an over-pressure area below approximately 2,500 metres across the Banarli Licences and the West Thrace lands and the potential for a basin-centered gas play;
- the tight gas delineation and development program in the Tekirdag field underpinning the reserves assessment for the TBNG JV lands, and the future potential vertical and horizontal wells and associated timing;
- tying-in new wells and getting these on-stream;
- the ability to manage water production to maximize oil and gas recovery;
- the ability to reduce costs, achieve capital efficiencies and increase production and the associated corporate sales outlook;
- results of future seismic programs;
- the availability of operating cash flow and the ability to finance exploration and development;
- future production rates and associated cash flow;
- the ability of the Company to obtain financing on acceptable terms;
- the ability of the Company to convert all or part of existing exploration licences into new production leases and to acquire new exploration licences through the application process under the New Petroleum Law;
- continued operations of and approvals forthcoming from the GDPA in a manner consistent with past conduct;
- political stability of the areas in which the Company is operating and completing transactions, and in particular, in the aftermath of the July 2016 failed coup attempt in Turkey;
- continued safety of operations and ability to proceed in a timely manner in the Thrace Basin;
- future economic conditions;
- future currency and exchange rates;

- the Company's continued ability to obtain and retain qualified staff, and equipment and services in a timely and cost efficient manner;
- technical decision making;
- the ability to execute and agree with partners on work programs (and the nature and extent of such work programs) and budgets, which are subject to change based on, amongst other things, the actual results of drilling and related activity, the availability of equipment and service providers, unexpected delays and changes in market conditions;
- the ability to obtain necessary government and stock exchange approvals;
- volume and product mix of Valeura's natural gas and oil production;
- the amount and timing of future asset retirement obligations;
- future liquidity, creditworthiness and financial capacity;
- future interest rates;
- future results from operations and operating metrics;
- future exploration, development and other expenditures;
- future costs, expenses and royalty rates; and
- future transaction and operational plans and the timing associated therewith.

Statements related to "reserves" are deemed forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves can be profitably produced in the future.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding and are implicit in, among other things:

- the ability of the Company to execute its strategy;
- the ability of the Company to satisfy the drilling and other requirements under its licences and leases;
- the ability of the Company to replace and expand oil and natural gas reserves through exploration, exploitation, development and acquisition;
- the ability to reach agreement with partners;
- the ability of the Company to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in foreign countries;
- field production rates and decline rates;
- the ability of the Company to secure adequate product transportation;
- the impact of increasing competition in or near the Company's plays;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner to develop its business and execute work programs;
- the Company's ability to operate the properties in a safe, environmentally responsible, efficient and effective manner;
- the timing and costs of pipeline, storage and facility construction and expansion;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- the regulatory framework regarding royalties, taxes and environmental matters;

- the ability of the Company to successfully market its oil and natural gas products;
- the ability to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in foreign countries;
- the state of the capital markets; and
- the ability of the Company to obtain financing on acceptable terms.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

Forward-looking statements are based on management's current expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities and future economic conditions. Forward-looking statements with respect to the Company's assets in Turkey are also based on management's assumptions that the oil and gas regulatory framework and political situation in Turkey will be stable and operate in its current state, and that the Company will obtain all necessary government and regulatory approvals to complete the activities described herein.

Forward-looking statements involve significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. A number of factors could cause actual results to differ materially from those anticipated by the Company including, but not limited to:

- the risks associated with the oil and gas industry (e.g. operational risks in exploration, inherent uncertainties in interpreting geological data, and changes in plans with respect to exploration or capital expenditures, the uncertainty of estimates and projections in relation to costs and expenses, and health, safety and environmental risks);
- uncertainty regarding the sustainability of initial production rates and decline rates thereafter;
- uncertainty regarding the ability to address technical drilling challenges and manage water production; uncertainty regarding the state of capital markets and the availability of future financings;
- the risk of being unable to meet drilling deadlines and the requirements under licences and leases;
- uncertainty regarding the availability of drilling rigs and associated equipment on the contemplated timelines for shallow and deep drilling programs;
- the risks of disruption to operations and access to worksites, threats to security and safety of personnel and potential property damage related to political issues, terrorist attacks, insurgencies or civil unrest;
- the risks of increased costs and delays in timing related to protecting the safety and security of Valeura's personnel and property;
- political stability in Turkey, including potential changes in political leaders or parties or a resurgence of a coup or other political turmoil;
- the risk of changing commodity prices and BOTAS reference prices (priced in TL);
- the risk of foreign exchange rate fluctuations, particularly the TL;
- the uncertainty associated with negotiating with third parties in countries other than Canada;
- the risk of partners having different views on work programs and potential disputes among partners;
- the uncertainty regarding government and other approvals (potential changes in laws and regulations);
- the risks associated with weather delays and natural disasters; and
- the risk associated with international activity.

The forward-looking statements contained herein are expressly qualified by this cautionary statement.

The forward-looking statements contained herein are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statement, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

VALEURA ENERGY INC.

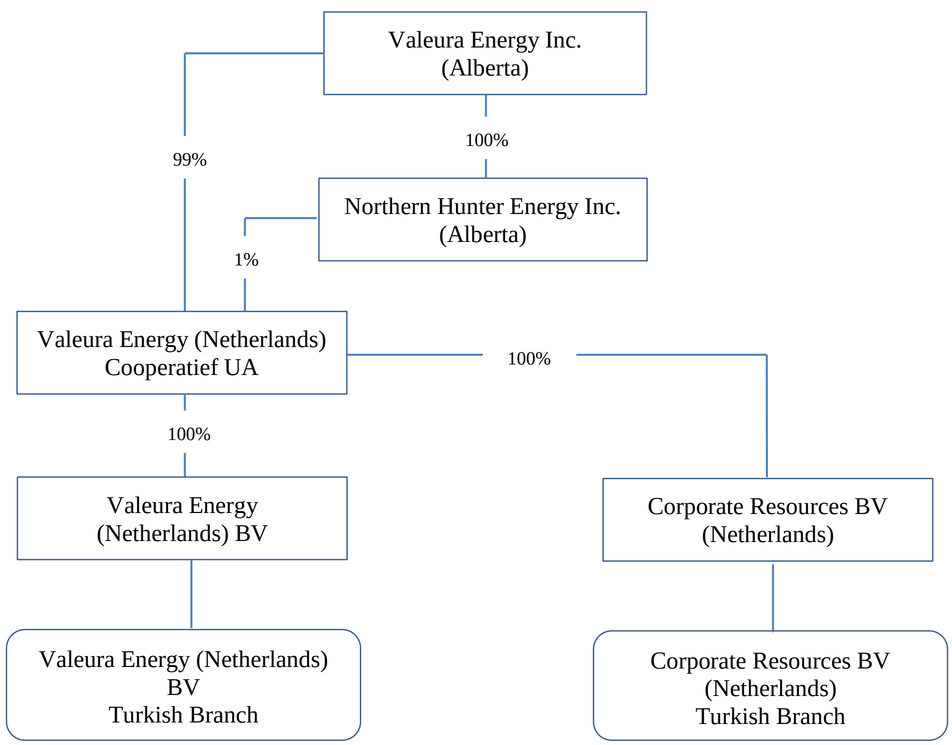
Valeura resulted from the business combination of PanWestern, a public company that was listed on the TSX Venture Exchange, and Northern Hunter, a private oil and gas company, completed on April 9, 2010 pursuant to the Arrangement. PanWestern was incorporated under the ABCA on June 7, 2000 and Northern Hunter was incorporated under the ABCA on September 1, 2006. Subsequent to the Arrangement, the Company filed articles of amendment on June 29, 2010 to change its name to Valeura Energy Inc. and on September 15, 2011 to consolidate the Common Shares on a 10 for 1 basis. The Company graduated to a TSX listing on September 15, 2011.

The head office of Valeura is located at Suite 1200, 202 – 6th Avenue SW, Calgary, Alberta, T2P 2R9 and its registered and records office is located at 4600, 525 – 8th Avenue SW, Calgary, Alberta, T2P 1G1.

The Common Shares are listed and posted for trading on the TSX under the symbol VLE.

Inter-Corporate Relationships

The following diagram describes the inter-corporate relationships among the Company and each of its material subsidiaries as at December 31, 2016; where each principal subsidiary was incorporated; and, the percentage of votes attaching to all voting securities of each subsidiary beneficially owned by Valeura and held by such subsidiaries.



As a result of the TBNG Acquisition, TBNG, a company organized under the laws of the British Virgin Islands with a branch in Turkey, became a wholly-owned subsidiary of VENBV. See "*General Development of the Business – Three Year History – Subsequent Developments*".

GENERAL DEVELOPMENT OF THE BUSINESS

In 2011, Valeura executed the TBNG-PTI Offer with TWL to jointly acquire non-operated producing natural gas assets and lands in the Thrace Basin in northwest Turkey and other interests in exploration lands in the Anatolian Basin in southeast Turkey from TBNG and PTI (the "**Initial TBNG Acquisition**"). The Initial TBNG Acquisition closed at a final purchase price, after adjustments, of US$57.3 million. The Initial TBNG Acquisition represented Valeura's first significant acquisition in Turkey.

Over the subsequent 2012 to 2016 period, the Company has grown and high-graded its initial platform in Turkey through new licence awards, in particular the Banarli Licence awarded in 2013, licence relinquishments and asset sales, see "*General Development of the Business - Three Year History*".

As of the date hereof, the Company held interests in 21 production leases and exploration licences in the Thrace Basin encompassing 0.53 million gross acres, see "*Description of the Business and Operations*". In 2016, the Company's net petroleum and natural gas sales in Turkey, all from the Thrace Basin, totalled 799 boe/d, of which 99% was natural gas with minor amounts of natural gas liquids and oil. Approximately 62% of these net sales were sourced from the TBNG JV lands and 38% from the Banarli Licences.

Three Year History

The following describes the development of Valeura's business over the last three completed financial years.

2014

In February 2014, the Company sold its 27.5% working interest in two Karakilise Licences 2674 and 2677 in the Anatolian Basin, which included two marginal oil wells producing in aggregate less than 10 bbl/d (net) of oil. Both licences were near expiry at the end of their 11-year term, requiring applications for production leases and relinquishment of the residual exploration areas by May 2014. The Company assessed that there was limited upside potential in retaining these licences.

In the third quarter of 2014, the Company sold its small non-strategic legacy oil and gas properties in Canada.

Through the course of 2014, Valeura, the TBNG JV and Valeura's other joint venture partners made applications to the GDPA under the New Petroleum Law to convert essentially all of Valeura's joint venture licenses and Banarli Licence 5104 (Valeura 100% working interest) into new exploration licences or new production leases. As a result, the end of 2014, Valeura, the TBNG JV and Valeura's other joint venture partners were awarded four new production leases in the TBNG JV (Valeura 40% working interest), three new production leases in the Edirne area in the Thrace Basin to replace the existing exploration licence (Valeura 35% working interest) and two new exploration licences in the Gaziantep area to replace the existing exploration licence (Valeura 26% working interest).

2015

Through the course of 2015, a number of additional exploration licence conversions were approved by the GDPA including two TBNG JV licences and Banarli Licence 5104, which was converted into the Banarli Licences. Also, seven new TBNG JV production lease applications were approved by the GDPA.

In the second quarter of 2015, Valeura initiated the exploration program on the Banarli Licences and completed 152 square kilometres of 3D seismic, which positioned the Company to drill two exploration wells (Valeura 100% working interest) in November and December 2015. The first of these wells Bati Gugen-1 was successfully production tested in December 2015 and was confirmed as a natural gas discovery. The second well Yayli-1 was cased in late December 2015.

2016

In the first quarter of 2016, the Bati Gurgen-1 well was tied into the TBNG JV gathering system. Production from the Bati Gurgen-1 well commenced on March 12, 2016. Two small fracs were carried out on the Yayli-1 well in tight, over-pressured sands near the base of the well at 2,700 to 2,900 metres, each of which achieved initial gas flow but flow could not be sustained. The Yayli-1 well is currently suspended, but has provided important information in exploring for unconventional natural gas in the deep over-pressured horizons proximal to the centre of the Thrace Basin.

In the second quarter of 2016, the Bati Gurgen-2 well was drilled and tied into the TBNG JV gathering system. Production from the Bati Gurgen-2 well commenced on September 26, 2016.

On August 19, 2016, Valeura announced that CRBV had entered into definitive transaction documents (the "**Definitive Agreements**") with Statoil for a farm-in agreement for the exploration of the deeper formations below approximately 2,500 meters on the Banarli Licences (the "**Barnali Farm-in**"). The Definitive Agreements include a farm-in agreement, a joint operating agreement to apply post-earning and a number of ancillary agreements. Under the terms of the Definitive Agreements, Statoil has the option to earn a 50% participating interest in the deep formations on the Banarli Licences by investing in an exploration program that includes payments and carried costs of at least US$36 million. The earning work program includes two deep exploration wells and additional 3D seismic. See "*Banarli Licences - Unconventional Tight Gas*".

On October 13, 2016, Valeura announced that:

- VENBV had entered into a share purchase agreement (the "**Acquisition Agreement**") with TransAtlantic to acquire 100% of the shares of TBNG (the "**TBNG Acquisition**");

- CRBV had entered into a sale and purchase agreement (the "**Deep Rights Sale Agreement**") with Statoil to sell Valeura's current 40% participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace lands, for cash consideration of US$12 million (the "**West Thrace Deep Rights Sale**"). The Deep Rights Sale Agreement provides that upon the closing of the West Thrace Deep Rights Sale and the TBNG Acquisition, CRBV will cause TBNG to enter into a sale and purchase agreement (the "**Subsequent Deep Rights Sale Agreement**") with Statoil to sell an additional 10% participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace lands, for cash consideration of US$3 million (the "**Subsequent West Thrace Deep Rights Sale**"); and

- it had entered into an agreement with Cormark Securities Inc. as lead underwriter, and on behalf of a syndicate of underwriters including GMP FirstEnergy, in respect of an underwritten $7.5 million (subsequently increased to $11.0 million) private placement financing of Subscription Receipts to be issued at a price of $0.75 per Subscription Receipt (the "**Offering**").

On November 3, 2016, Valeura announced the closing of the Offering.

Subsequent Developments

On January 6, 2017, Valeura announced: the closing of the Banarli Farm-in and the receipt of a payment by Statoil of US$6 million for back costs; and the closing of the West Thrace Deep Rights Sale and the receipt of a payment by Statoil of US12 million.

On January 17, 2017, the TBNG JV relinquished two non-producing exploration licences in the Gaziantep area in the Anatolian Basin, representing an exit by Valeura from southeast Turkey.

On February 2, 2017, the GDPA awarded two production leases F19-d3-1 and F19-c3-1 in the Thrace Basin to the TBNG JV.

On February 24, 2017, Valeura announced the closing of the TBNG Acquisition for a final purchase price, after adjustments, of US$20.9 million (which includes US$3.1 million held in escrow pending a final reconciliation of the closing statement of adjustments) and the issuance of 14,629,000 Common Shares pursuant to 14,629,000 Subscription Receipts issued in connection with the Offering, and the release from escrow of approximately $11 million in gross proceeds.

On March 10, 2017, TBNG entered into the Subsequent Deep Rights Sale Agreement.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Valeura is a Canada-based public company currently engaged in the exploration, development and production of petroleum and natural gas in the Thrace Basin of northwest Turkey.

Corporate Strategy

The Initial TBNG Acquisition represented Valeura's first significant acquisition in Turkey. The Company continues to be focussed on growing its natural gas operations in the Thrace Basin, where natural gas prices remain robust compared to North America. The Banarli Farm-in, the Offering, the West Thrace Deep Rights Sale and the TBNG Acquisition have transformed the Company by increasing the size of the asset base, degree of operational control and financial capacity, and secured a large, well-respected partner to pursue a deep high impact exploration program. These transactions pave the way for a significant ramp-up in the exploration and development program in 2017 and future years.

In this regard, the Company is targeting to achieve the following key objectives:

- grow the relatively low risk shallow gas business on the newly consolidated and operated TBNG JV lands and Banarli Licences (less than 2,500 metres depth);
- explore for a higher risk/higher reward deep, basin-centered gas accumulation play (2,500 metres to 4,000+ metres depth), initially funded by Statoil under the Banarli Farm-in; and
- pursue expansion of the asset base in the Thrace Basin though new licence awards or other transactions.

Personnel

As at December 31, 2016, Valeura had nine full-time employees in its head office in Calgary, as well as five full-time employees in its branch in Ankara, Turkey. As a result of the TBNG Acquisition, Valeura acquired more than 50 TBNG employees.

Operations

The following table sets forth Valeura's land holdings in Turkey as of the date hereof.

Area	Leases & Licences (#)	Gross Acres (acres)	Valeura Net Area - Shallow Rights (acres)	Valeura Net Area - Deep Rights(1) (acres)
Thrace Basin				
TBNG JV Licences & Leases(2)(3)	16	344,781	280,996	193,973
Banarli Licences(4)(5)	2	133,840	133,840	133,840
Edirne Leases	3	49,883	17,459	17,459
Total	**21**	**528,504**	**432,295**	**345,272**

Notes:

(1) Post West Thrace Deep Rights Sale and Subsequent West Thrace Deep Rights Sale (aggregate 87,023 net acres of deep rights sold to Statoil) but prior to potential earning by Statoil of 50% in the deep rights on the Banarli Licences under the Banarli Farm-in.

(2) Reflects February 2017 approval of two new production leases including F19-d3-1 as a carve-out from expired exploration licence 3934 and F19-c3-1 as a carve-out from expired exploration licence 4126.

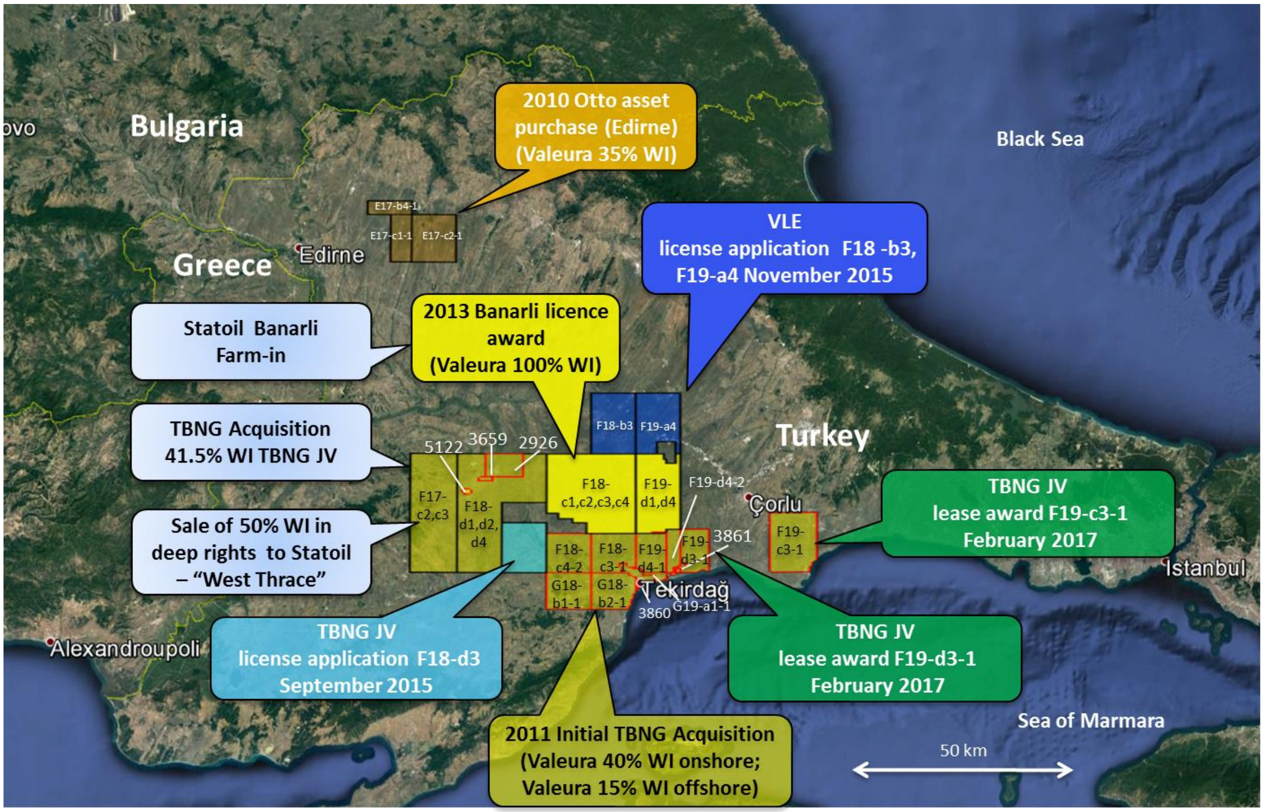
(3) The TBNG JV requested and the GDPA subsequently posted part of the area encompassed by the relinquished old exploration licence 3858 (30,048 gross acres) for new bids (submitted September 16, 2015). Potential acreage additions from this bid have been excluded from the table. Bids remain under review by the GDPA.

(4) The gross and net acreage shown includes 9,981 acres in the northeast corner of licence F19-d1, d4 that could revert to TPAO if certain work program obligations are performed by TPAO on this land. This small area was once held by TPAO as part of a larger licence that expired prior to the Banarli licence conversion process but was included by the GDPA in the new Banarli licence F19-d1, d4 to enable its adaptation to encompass all of the un-licenced area in the quadrant.

(5) Excludes any potential acreage additions from bids submitted by Valeura to the GDPA for two new exploration licences (F18-b3 and F19-a4) contiguous with the Banarli licences. These bids remain under review by the GDPA.

THRACE BASIN

Approximately 99% of Valeura's production in Turkey is natural gas produced in the Thrace Basin. The map below depicts Valeura's assets in the Thrace Basin as at the date hereof.



TBNG JV Lands

As part of the Initial TBNG Acquisition, Valeura acquired a 40% non-operated working interest in four production leases and 10 exploration licences in the Thrace Basin, of which two licences were entirely on land, three licences had a portion in the shallow waters of the Sea of Marmara (up to 200 metre water depth), and five licences were in deeper water (200 to 1,200 metre water depth). The five deep offshore licences were subsequently relinquished in 2011.

One onshore exploration licence (3734) also expired in 2012, after the carve-out of a new production lease, and the relinquished lands were subsequently re-acquired (5151) through a successful application process in 2013.

In the fourth quarter of 2014, the TBNG JV was awarded four new production leases (F18-c4-2, F18-c3-1, F19-d4-1 and F19-d4-2) over part of two existing exploration licences.

In 2015, the GDPA approved an application by the TBNG JV to relinquish expiring exploration licence 3858 and to convert exploration licence 5151 to the new licencing terms under the New Petroleum Law. As a result, the TBNG JV was awarded two new exploration licences (F17-c2, c3 and F18-d1, d2, d4) to replace licence 5151 with an aggregate area of 160,468 gross acres (64,187 net acres). The new licences also encompass part of the expired licence 3858. The TBNG JV made application to the GDPA to post the residual area of expired licence 3858 and submitted a bid for a new exploration licence (F18-d3) in September 2015. This bid remains under review by the GDPA.

During the course of 2015, the TBNG JV was awarded an additional three production leases (G18-b1-1, G18-b2-1 and G19-a1-1) over part of expired exploration licences 3913 and 3934.

In the first quarter of 2017, the TBNG JV was awarded an additional two production leases (F19-d3-1 and F19-c3-1) over part of expired licences 3934 and 4126.

Natural gas is currently produced from both conventional and unconventional (tight gas) sandstone reservoirs in the leases and licences on the TBNG JV lands. Gas sales from the TBNG JV lands in 2016 averaged 7.5 MMcf/d (gross) or 3.0 MMcf/d (net). Oil and natural gas liquids sales totalled 13 bbl/d (gross) or 5 bbl/d (net). Average realized prices for Valeura's gas sales from the TBNG JV lands were $9.46 per Mcf in 2016.

The TBNG JV has had an active exploration and development program, particularly over the 2011 to 2014 period as described below. In 2015 and 2016, the activity level was reduced as the TBNG JV partners redirected cash flow to other opportunities outside the TBNG JV. In the case of Valeura, cash flow from the TBNG JV was directed to the initiation of an exploration and development program on the Banarli Licences. Nonetheless, opportunities exist to further exploit the shallow gas and tight resource potential on the TBNG JV lands through exploration and development drilling, well workovers, and additional wellhead compression to mitigate natural declines. As a result of the TBNG Acquisition, Valeura intends to ramp-up the exploration and development program on the TBNG JV lands in 2017.

Conventional Shallow Gas

As at December 31, 2016, approximately 60% of the natural gas produced from the TBNG JV lands was conventional shallow gas produced from approximately 53 wells. Shallow gas is produced from Tertiary-aged stacked sands in the Danismen and Osmancik formations at relatively shallow depths of 500 to 1,500 metres. The gas, which is composed primarily of methane, is gathered, dehydrated and compressed in owned facilities and distributed on an owned sales line network directly to 55 light industry customers. TBNG manages the marketing arrangements under a marketing licence administered by EMRA.

The TBNG JV has had an active program to exploit the conventional shallow gas resource on the TBNG JV lands. In summary, the following table illustrates programs that were completed over the 2012 to 2017 year to date period:

Year	**Work Program**
2012	32 well workovers and nine new shallow exploration and development drill wells (gross).
2013	14 well workovers, 232 square kilometres of 3D seismic in the Osmanli area and one new shallow gas development drill well (gross).
2014	21 well workovers, two well re-entry fracs in the Osmancik formation and six new exploration and development vertical wells (including one sidetrack) (gross) drilled on new Osmanli area 3D seismic.
2015	one development vertical drill well (gross) drilled as an appraisal well in the Osmanli area and nine well workovers.
2016	one well workover.
2017 YTD	one new shallow gas exploration well (gross).

Opportunities exist to ramp-up the shallow, conventional gas exploration and development program, as planned by Valeura in 2017. In particular, new 3D seismic has assisted in identifying new gas exploration play types. The initial acquisition of 413 square kilometres of new 3D seismic in the Tekirdag and Hayrabolu areas was completed in mid-October 2011 and positioned a ramp-up of deeper, tight gas drilling and selected shallow gas drilling in the second quarter of 2012. In the third and fourth quarters of 2013, an additional 232 square kilometers of 3D seismic was acquired in the Osmanli area and merged with the Tekirdag area 3D seismic to provide coverage over a contiguous area of more than 400 square kilometres.

The Osmanli 3D seismic identified a number of drilling opportunities for both conventional shallow gas and deeper unconventional tight gas. In the second half of 2014 and early 2015, the Company completed an initial program of seven (gross) conventional gas exploration and development wells in the Osmanli area. All seven wells were cased, of which six are producing.

Increasingly sophisticated seismic interpretation techniques have been applied to the Hayrabolu, Tekirdag and Osmanli 3D seismic surveys and have identified a number of new drilling opportunities which are expected to be pursued in 2017 and future years.

Unconventional Tight Gas

Valeura acquired its position in the Thrace Basin with the expectation that in addition to further potential in the well-established conventional shallow gas operation there was significant upside potential associated with applying modern multi-stage frac completion technology to exploit deeper unconventional tight gas sands in the Mezardere, Teslimkoy, and Kesan formations in structures that underlie the shallow gas reservoirs. The tight gas formations had seen minimal development in the past. Producing analogies in the Thrace Basin and well results from a small number of deeper wells drilled in the past on the TBNG JV lands indicated the presence of relatively low porosity (6 to 15%), stacked sandstone reservoirs in these formations that tested gas, but these tight gas formations were generally not producible at commercial rates in the absence of fracture stimulation.

There are many other analogies of tight gas reservoirs around the world in similar basins that have benefited from the application of modern drilling and well stimulation technologies and robust capital investment. In parts of the Thrace Basin, there are up to 5,000 metres of sediments with a number of tight gas targets that are expected to benefit from multi-stage fracs in vertical wells, given the relatively large gross thickness of the target interval, or in horizontal wells in selected horizons as geological understanding and frac experience grow.

Unlocking the potential in the deeper unconventional tight gas play in the Thrace Basin has been a focus for the Company since mid-2011. The TBNG JV has carried out an extensive proof-of-concept program since 2011 to de-risk the tight gas play. As at December 31, 2016, approximately 40% of the natural gas produced from the TBNG JV lands was tight gas produced from approximately 32 wells.

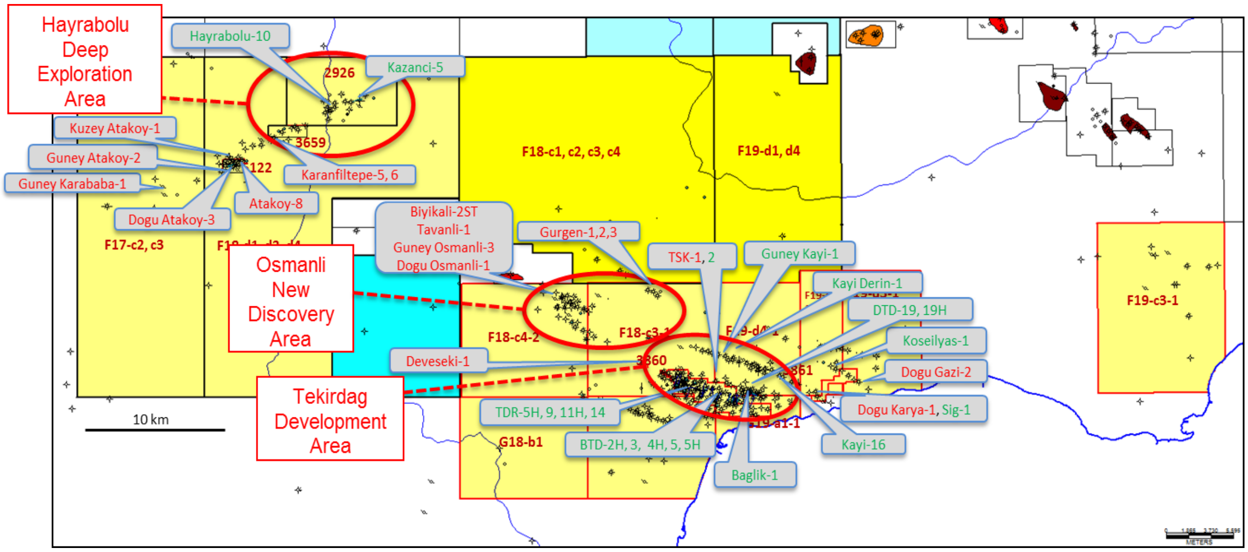
In summary, the following programs were completed to exploit the unconventional tight gas on the TBNG JV lands over the 2012 to 2017 year to date period:

Year	**Work Program**
2012	11 vertical exploration and development drill wells (gross), of which the deepest was drilled to 3,755 metres.
2013	three vertical exploration and development drill wells (gross), of which the deepest was drilled to 4,054 metres, and three horizontal development wells (gross).
2014	three horizontal development wells (gross).
2011-2014	73 fraced wells (gross) (55 well re-entry fracs in vertical wells, 12 fracs on new deep vertical wells and six multi-stage fracs in six new horizontal wells). This program included five well re-entry fracs in lower porosity intervals in the Osmancik formation.

Opportunities exist to pursue further tight gas development particularly in the Tekirdag field and a potential development plan consisting of more than 62 wells has been defined and underpins the proved, probable and possible reserves in this field.

The West Thrace Deep Rights Sale adds potential for a more active deep exploration program on the West Thrace lands, which have potential for an over-pressured basin-centered gas play, likely following Statoil’s completion of the Banarli Farm-in program.

The Company’s conventional shallow gas (red) and unconventional tight gas (green) drilling program in the 2012 to 2017 period on the TBNG JV lands is illustrated in the figure and table below.



Time	Gross Wells Spudded	Producing	Evaluating/ Completing	Cased & Standing	Plugged & Abandoned	Drilling
Unconventional						
2012 - 2013	17	15	1	-	1	-
2014	3	3	-	-	-	-
Conventional						
2012 - 2013	10	6	2	-	2	-
2014	6	5	1	-	-	-
2015	1	1	-	-	-	-
2017 YTD	1	-	1	-	-	-
Total 2012 – 2017 YTD	**38**	**30**	**5**	**-**	**3**	**-**

Banarli Licences

In 2013, Valeura was awarded Banarli Licence 5104 (Valeura 100% working interest) in the Thrace Basin. Banarli Licence 5104 had a four-year initial term and covered an area of 118,598 gross acres located near the centre and deepest part of the Thrace Basin. In June 2013, Valeura completed a 93 kilometre 2D seismic program to complement the existing 2D seismic coverage on Banarli Licence 5104 of more than 200 kilometres. Only two relatively shallow wells had been drilled prior to Valeura's ownership of Banarli Licence 5104, the last well being the Karaca-1 well, which was plugged and abandoned at a depth of 1,026 metres in November 2010.

In the second quarter of 2015, the GDPA approved Valeura's application to convert the Banarli Licence 5104 into the contiguous Banarli Licences with an area of 133,840 gross acres. The initial term of the Banarli Licences has been extended to June 27, 2020 under the New Petroleum Law. During the initial term, the Company is required to complete, in aggregate on the Banarli Licences, 152 square kilometres of 3D seismic and drill three wells, including a 2,000 metre well in each of year one and year two and a 3,800 metre well in year four. To date, all the required 3D seismic program and the two-well shallower drilling program has been completed. The Company expects to complete the final drilling commitment of a 3,800 metre well in 2017 pursuant to the Banarli Farm-in.

Conventional Shallow Gas

Commencing in early 2015, Valeura has been pursuing a new Banarli strategy focussed on exploring the Osmancik and Mezardere formations down to a depth of approximately 2,500 metres on a 100% Valeura basis. As an initial step in this strategy, Valeura acquired 152 square kilometres of 3D seismic in the second quarter of 2015 and merged this with the 3D seismic at Osmanli and Tekirdag providing an interpreted data set covering more than 580 square kilometres.

Valeura subsequently drilled two vertical exploration wells on the Banarli Licences in November and December 2015 and a third well in June 2016.

The first of these exploration wells, Bati Gurgen-1, was drilled to a depth of 2,735 metres into the top of the Teslimkoy member of the Mezardere formation, with the primary target being shallower conventional gas in the Osmancik formation. The relatively tight Teslimkoy member was first evaluated with a diagnostic fracture injection test which confirmed that the Teslimkoy member is over-pressured. However, the net pay encountered to this depth in the Teslimkoy member was not sufficient to warrant a frac. The Bati Gurgen-1 well was therefore completed in the Osmancik formation at a depth of approximately 1,500 metres. The Bati Gurgen-1 well was tied-in to a TBNG JV dehydration facility located about 3 kilometres away and first natural gas sales were achieved on March 12, 2016. The gas is being sold to the TBNG JV, which in turn is being distributed to its existing customer base. The Bati Gurgen-1 well produced at an average restricted IP30 rate of 3.4 MMcf/d.

The second exploration well, Yayli-1, was drilled to a depth of 2,914 metres penetrating an attractive interval in the Osmancik formation with shallow gas potential. The Yayli-1 well also penetrated multiple over-pressured, tighter stacked sands in the Teslimkoy member. A diagnostic fracture injection test confirmed that this Teslimkoy interval is over-pressured to the same extent as encountered in the Bati Gurgen-1 well. Two small fracs were completed in the over-pressured tight gas sands in the Teslimkoy formation in the Yayli-1 well at a depth of 2,700 to 2,900 metres, each of which achieved initial gas flow but the flow could not be sustained. A completion in the shallower Osmancik formation was not successful due to high water production. The Yayli-1 well is currently suspended, but has provided important information in exploring for unconventional natural gas in the deep horizons and attracting a joint venture partner.

The third exploration well, Bati Gurgen-2, was drilled to a depth or 2,226 metres but the target Danismen and Osmancik were deeper than expected. A successful sidetrack drilling operation was then carried out and the Osmancik formation was completed and the Bati Gurgen-2 well was placed on production on September 26, 2016. The Bati Gurgen-2 well produced at an average restricted IP30 rate of 1.1MMcf/d.

Gas sales from the Banarli Licences in 2016 averaged 1.8 MMcf/d (gross and net). Oil and natural gas liquids sales totalled 4 bbl/d (gross and net). Average realized prices for Valeura's gas sales from the Banarli Licences were $8.79 per Mcf in 2016.

Unconventional Tight Gas

Valeura continues to believe that there is significant upside potential for an unconventional basin-centred gas play in the deeper horizons below 2,500 metres in a potential pressure-seal area of more than 1,500 square kilometers proximal to the centre of the Thrace Basin encompassing the Banarli Licences and the West Thrace lands. The over-pressure measurements in the Bati Gurgen-1 and Yayli-1 wells and gas flows achieved from two small fracs in the Yayli-1 well have provided further encouraging data points but further drilling and production testing will be required to prove up the play. Below 2,500 metres, the source rock shales and reservoir sands in this potential pressure-seal area could be in an active hydrocarbon-generating "kitchen" forming a basin-centered gas accumulation, with regionally pervasive, low permeability, gas-saturated sandstone reservoirs exhibiting abnormally high pressures. In contrast, the tight gas formations being developed to-date on the South Thrace lands have been normally-pressured.

It is expected that in 2017 Statoil will fund the drilling of a 4,000 metre exploration well to spud in the second quarter of 2017 and acquire extensive 3D seismic in the third and fourth quarters pursuant to the Banarli Farm-in. A second well must be funded by Statoil in order to earn a 50% participating interest in the deep formations. Valeura retains a 100% participating interest in the shallow formations to a depth of 2,500 metres. Valeura will operate this deep exploration program during Statoil's earning phase at the same time as it continues to operate the shallow gas program on the Banarli Licences.

In summary, the following programs were completed to exploit conventional shallow gas in the Danismen and Osmancik formations and unconventional tight gas in the Osmancik, Mezardere, Teslimkoy and Kesan formations on the Banarli Licences:

Year	Work Program
2015	152 square kilometres of 3D seismic, two exploration wells at Bati Gurgen-1 and Yayli-1.
2016	one exploration well at Bati Gurgen-2, two fracs in the Yayli-1 well and one re-completion in the Bati Gurgen-1 well.

Edirne Leases

In 2010, Valeura acquired a 35% non-operated working interest in the Edirne Exploration Licence 3839 in the Thrace Basin from a wholly-owned affiliate of Otto Energy Ltd. In the fourth quarter of 2014, Edirne Exploration Licence 3839 was converted under the New Petroleum Law into three production leases in quadrants E17-b4-1, E17-c1-1 and E17-c2-1 (collectively, the "Edirne Leases"). An affiliate of TransAtlantic operates the Edirne assets.

Gas sales from the Edirne Leases in 2016 averaged 0.04 MMcf/d (gross) or 0.01 MMcf/d (net). Average realized prices for Valeura's gas sales from Edirne Leases were $7.43 per Mcf in 2016.

The gas at Edirne is processed (dehydration and compression) on a fee basis in a third-party owned facility and is tied into the pipeline system operated by BOTAS located nine kilometres from the plant, which carries imported Russian gas to the Istanbul area and other cities in Turkey, and sold on a wholesale basis.

In the 2014 to 2016 period, there was no drilling carried out given the maturity of the asset and limited exploration or development drilling opportunities.

ANATOLIAN BASIN

Gaziantep Licences

As part of the Initial TBNG Acquisition, Valeura acquired a 26% non-operated working interest in five exploration licences in the Anatolian Basin located near the city of Gaziantep. Gaziantep Exploration Licence 4638 was relinquished in 2011 and Gaziantep Exploration Licences 4648, 4649 and 4656 were relinquished in 2013. In the fourth quarter of 2014, Gaziantep Exploration Licence 4607 was converted under the New Petroleum Law into two exploration licences in quadrants N39-a1, a4 and N39-d1, d2. These licences were relinquished in January 2017 due to limited prospectivity and an impending drilling commitment.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Company engaged D&M to prepare a report relating to the Company's reserves in Turkey as at December 31, 2016. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Company's crude oil and conventional natural gas reserves in Turkey are located in the Thrace Basin area of Turkey. Set out below is a summary of the crude oil and conventional natural gas reserves and the value of future net revenue of the Company as at December 31, 2016 as evaluated by D&M in the D&M Reserves Report. A summary of the D&M Reserves Report and accompanying narrative (in Form 51-101F1), as well as the report on the reserves data by D&M (in Form 51-101F2) and the report of the Company's management on such reserves data (in Form 51-101F3) are included in this Annual Information Form as Appendices A-1, A-2 and A-3, respectively.

The D&M Reserves Report does not give effect to the TBNG Acquisition. See "Statement of Reserves Data and Other Oil and Gas Information - TBNG Acquisition Pro Forma".

The following is a summary of the D&M Reserves Report which is qualified in its entirety by the Company's Statement of Reserves Data and Other Oil and Natural Gas Information (Turkey) attached as Appendix A-1 hereto.

Oil and Gas Reserves
Based on Forecast Prices and Costs[9]

	Light and Medium Oil Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent[10]	
	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (MMcf)	Net[1] (MMcf)	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (Mboe)	Net[1] (Mboe)
Proved Developed Producing[(2)(5)(6)]	6	6	-	-	2,782	2,416	-	-	470	409
Proved Developed Non-Producing[(2)(5)(7)]	0	0	-	-	2,428	2,108	-	-	405	351
Proved Undeveloped[(2)(8)]	0	0	-	-	4,153	3,593	-	-	692	599
Total Proved[(2)]	6	6	-	-	9,363	8,117	-	-	1,567	1,359
Total Probable[(3)]	3	3	-	-	18,803	16,286	-	-	3,137	2,717
Total Proved Plus Probable[(2)(3)]	9	9	-	-	28,166	24,403	-	-	4,704	4,076
Total Possible[(4)]	5	4	-	-	15,125	13,112	-	-	2,526	2,189
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	14	13	-	-	43,291	37,515	-	-	7,230	6,265

Net Present Values of Future Net Revenue
Based on Forecast Prices and Costs[(9)(11)]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes[(11)] Discounted At				
	0% (M US$)	5% (M US$)	10% (M US$)	15% (M US$)	20% (M US$)	0% (M US$)	5% (M US$)	10% (M US$)	15% (M US$)	20% (M US$)
Proved Developed Producing[(2)(5)(6)]	8,334	7,551	6,916	6,388	5,939	8,334	7,551	6,916	6,388	5,939
Proved Developed Non-Producing[(2)(5)(7)]	11,712	7,492	5,112	3,718	2,864	10,290	6,641	4,570	3,348	2,593
Proved Undeveloped[(2)(8)]	8,088	5,442	3,503	2,079	1,032	6,121	3,891	2,283	1,119	277
Total Proved[(2)]	28,134	20,485	15,531	12,185	9,835	24,745	18,083	13,769	10,855	8,809
Total Probable[(3)]	67,329	44,580	30,184	20,911	14,837	54,279	35,951	24,388	16,964	12,113
Total Proved Plus Probable[(2)(3)]	95,463	65,065	45,715	33,096	24,672	79,024	54,034	38,157	27,819	20,922
Total Possible[(4)]	75,413	47,162	31,069	21,517	15,607	61,099	38,250	25,316	17,661	12,930
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	170,876	112,227	76,784	54,613	40,279	140,123	92,284	63,473	45,480	33,852

Notes:

(1) "**Gross Reserves**" are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.

(2) "**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "**Possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "**Developed**" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

(6) "**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(7) "**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(8) "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(9) The pricing assumptions used in the D&M Reserves Report with respect to net values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth in Appendix A-1 in a table titled "Forecast Prices & Cost Escalation Rates Used in D&M Reserves Report". The Forecast Prices & Cost Escalation rates were developed by D&M as at December 31, 2016 and reflect the then current year forecast prices and cost escalation rates. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(10) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(11) Income taxes are Turkey income taxes.

TBNG Acquisition Pro Forma

On February 24, 2017, the Company announced the successful completion of the TBNG Acquisition. TBNG holds a 41.5% participating interest in the TBNG JV. The following table sets out certain operating information with respect to Valeura and TBNG and pro-forma combined reserves information for Valeura and TBNG as at December 31, 2016.

	Pro Forma Reserves, Net Present Value At 10% Before Tax Information Year Ended December 31, 2016 and Production for the Three Months Ended December 31, 2016[5]			
	Valeura[1]	**TBNG[2]**	**Pro Forma**	**Change %**
RESERVES				
Gross Proved Reserves				
Light and Medium Crude Oil (Mbbls)	6	4	10	-
Conventional Natural Gas (MMcf)	9,363	7,882	17,245	-
Total Oil Equivalent (Mboe)	1,567	1,318	2,885	84
Gross Proved plus Probable Reserves				
Light and Medium Crude Oil (Mbbls)	9	6	15	-
Conventional Natural Gas (MMcf)	28,166	25,152	53,318	-
Total Oil Equivalent (Mboe)	4,704	4,198	8,902	89
Gross Proved plus Probable plus Possible Reserves				
Light and Medium Crude Oil (Mbbls)	14	9	23	-
Conventional Natural Gas (MMcf)	43,291	37,839	81,130	-
Total Oil Equivalent (Mboe)	7,230	6,315	13,545	87
RESERVES VALUE – NET PRESENT VALUE AT 10% BEFORE TAX (US$MM) [3]				
Gross Proved Reserves	15.5	10.5	26.0	68
Gross Proved plus Probable Reserves	45.7	35.5	81.2	78
Gross Proved plus Probable plus Possible Reserves	76.8	59.6	136.4	78
PRODUCTION [4]				
Light and Medium Crude Oil (bbls/d)	12	7	19	-
Conventional Natural Gas (Mcf/d)	4,699	2,518	7,217	-
Total Oil Equivalent (boe/d)	795	427	1,222	54

Notes:

(1) D&M evaluated reserves as at December 31, 2016 on the Company's Banarli lands (100% working interest) and on the TBNG JV lands (40% working interest).

(2) TBNG's working interest in the TBNG JV lands is 41.5%. TBNG's reserves as of December 31, 2016 as presented were prepared internally (non-independent) by Valeura by making a mathematical adjustment of the Company's TBNG JV lands reserves that represents a 40% working interest to reflect TBNG's 41.5% working interest.

(3) The forecast prices used in the calculations of the present value of future net revenue for year-end 2016 are based on the D&M December 31, 2016 forecast prices, which are contained in this Annual Information Form and Form 51-101F1 attached hereto.

(4) Based on annualized Q4 2016 sales.

(5) Due to rounding, summations in the table may not add.

DESCRIPTION OF CAPITAL STRUCTURE

Valeura is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares (the "**Preferred Shares**").

As at December 31, 2016, there were 58,519,321 Common Shares and nil Preferred Shares outstanding. As of the date hereof, there were 73,148,321 Common Shares outstanding as a result of the Offering. In addition, as of the date hereof, there were 4,914,500 Options outstanding.

Common Shares

The Company is authorized to issue an unlimited number of Common Shares. The holders of the Common Shares are entitled to dividends, if, as and when declared by the Board, to one vote per share at meetings of the Shareholders and, upon liquidation, to receive such assets of the Company as are distributable to the holders of the Common Shares.

Preferred Shares

The Company is authorized to issue an unlimited number of Preferred Shares, issuable in series. Each series of Preferred Shares will have such designations, rights, privileges, restrictions and conditions as the Board may from time to time determine before issuance. The holders of each series of Preferred Shares will be entitled, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount of dividends, if any, specified as being payable preferentially to the holders of such series and, upon liquidation, dissolution or winding-up of the Company, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

DIVIDENDS

Valeura has not declared or paid any dividends on the Common Shares since incorporation. It is not currently expected that dividends will be paid in respect of the Common Shares during the current phase of development of Valeura's business and operations. The payment of dividends in the future will be at the discretion of the Board and will be dependent on the future earnings and financial condition of the Company and such other factors as the Board considers appropriate.

PRIOR SALES

During the financial year ended December 31, 2016, 613,000 Options were issued with an exercise price of $0.75, and 875,500 Options were exercised or forfeited.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol VLE. The following table sets forth the price ranges and traded volume of Common Shares in 2016 as reported by the TSX.

2016	High	Low	Volume
January	0.80	0.60	5,837,000
February	0.83	0.72	3,270,700
March	0.79	0.61	3,188,100
April	0.88	0.64	3,375,600
May	1.22	0.60	7,073,100
June	1.44	1.10	3,635,000
July	1.25	0.90	2,537,500
August	1.20	0.80	1,811,600
September	1.08	0.82	1,339,500
October	1.15	0.81	1,674,600
November	0.98	0.82	635,100
December	0.95	0.82	875,400

DIRECTORS AND EXECUTIVE OFFICERS

The following table sets forth the names, province or state and country of residence, present positions with Valeura and principal occupations during the past five years of the officers and directors of Valeura. The term of office for each director is from the date of the annual meeting at which they are elected until the next annual meeting or until their successor is elected or appointed.

Name and Residence	Position(s) with Valeura	Principal Occupation(s) During the Past Five Years
Stephen E. Bjornson(4) Calgary, Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Valeura since April 9, 2010.
William T. Fanagan(1)(2) Vancouver, British Columbia, Canada	Director since 2010	Private Businessman since August 2001.
Claudio A. Ghersinich(2)(3)(4) Calgary, Alberta, Canada	Director since 2010	President and Chief Executive Officer of Carrera Investments Corp. since May 2005. Director of Vermilion Energy Inc. since 1994. Chairman of the Board, ArPetrol Ltd. from March 2011 to December 2016.
Dr. Timothy R. Marchant(1)(3) Calgary, Alberta, Canada	Director since 2015	Adjunct Professor of Strategy and Energy Geopolitics, Haskayne School of Business, University of Calgary Director of Vermilion Energy Inc. since 2010. Director of Cub Energy Inc. since 2013.
Lyle A. Martinson Calgary, Alberta, Canada	Vice President, Operations	Vice President, Operations of Valeura since April 9, 2010.
James D. McFarland Calgary, Alberta, Canada	President and Chief Executive Officer, Director since 2010	President and Chief Executive Officer of Valeura since April 9, 2010.
Ronald W. Royal(2)(3) Abbotsford, British Columbia, Canada	Director since 2010	Private Businessman since April, 2007. Director of Gran Tierra Energy Inc. since 2015. Director of Caracal Energy Inc. from July 2011 to July 2014. Director of Oando Energy Resources Inc. from April 2015 to May 2016.
Donald W. Shepherd Calgary, Alberta, Canada	Vice President, Engineering	Vice President, Engineering of Valeura since April 9, 2010.

Notes:

(1) Member of the Governance and Compensation Committee.
(2) Member of the Audit Committee.
(3) Member of the Reserves & Health, Safety and Environment Committee.
(4) Messrs. Bjornson and Ghersinich were directors of Northern Hunter since 2006.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly, 3,348,209 Common Shares representing approximately 4.6% of the issued and outstanding Common Shares.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly 3,353,000 Options. If all such Options were exercised, the directors and executive officers of Valeura, as a group, would hold approximately 8.6% of the then issued and outstanding Common Shares (on a fully diluted basis).

Corporate Cease Trade Orders or Bankruptcies

To the knowledge of management, no director or executive officer of Valeura is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days.

To the knowledge of management, no director, executive officer of Valeura is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity or within a year of that issuer ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

To the knowledge of management, no director or executive officer of Valeura has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

To the knowledge of management, no director or executive officer of Valeura has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Circumstances may arise where Board members are directors or officers of companies which are in competition to the interests of Valeura. No assurances can be given that opportunities identified by such Board members will be provided to Valeura. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the Board is voting are required to disclose their interests and refrain from voting on the transaction.

AUDIT COMMITTEE

Composition of the Audit Committee

The Audit Committee of the Board operates under written terms of reference that set out its responsibilities and composition requirements. A copy of the terms of reference is attached to this Annual Information Form as Appendix "B". The Audit Committee consists of Messrs. Fanagan (Chair), Ghersinich and Royal. All members of the Audit Committee are independent and financially literate as such terms are defined by National Instrument 52-110 - Audit Committees.

The following sets out the education and experience of each director relevant to the performance of his duties as a member of the Audit Committee. The chair of the Audit Committee, William T. Fanagan, holds a chartered accountant designation from the Institute of Chartered Accountants in Ireland and has accounting and financial expertise as a result of his experience as the President and Chief Executive Officer of a publicly traded international oil and gas company. Mr. Claudio A. Ghersinich holds a B.Sc. Civil Engineering degree from the University of Manitoba and has obtained financial experience and exposure to accounting and financial issues in a role as a founder of a publicly traded oil and gas company in 1994 and as an audit committee member of other public companies. Mr. Ronald W. Royal holds a Bachelor of Applied Science degree in Mechanical Engineering from the University of British Columbia and has obtained financial experience and exposure to accounting and financial issues through his involvement as an executive officer of international affiliates of ExxonMobil Corporation.

Auditors' Fees

KPMG LLP, Chartered Accountants, became Valeura's auditors on April 9, 2010. Fees paid to Valeura's auditors for the years ended December 31, 2016 and 2015 are detailed below.

Fee	For the year ended December 31, 2016	For the year ended December 31, 2015
Audit Fees(1)	$222,200	$247,829
Tax Fees(2)	-	-
All Other Fees	$29,920	$12,600
Total	$252,120	$260,429

Notes:

(1) "**Audit Fees**" include the aggregate professional fees paid to the external auditors for the audit of the annual consolidated financial statements and other annual regulatory audits and filings. It also includes the aggregate fees paid to the external auditors for services related to the audit services, including reviewing quarterly financial statements and management's discussion thereon and consulting with the Board and Audit Committee regarding financial reporting and accounting standards.

(2) "**Tax Fees**" include the aggregate fees paid to external auditors for tax compliance, tax advice, tax planning and advisory services, including preparation of tax returns.

All permissible categories of non-audit services require pre-approval by the Audit Committee, subject to certain statutory exemptions.

RISK FACTORS

Foreign Operations

Valeura currently has all of its operations in Turkey and will likely continue to have all of its operations outside of Canada. Exploration, development and operating activities in Turkey are subject to the risks normally associated with the conduct of business in countries with less developed or emerging economies. As such, the Company's operations, financial condition and operating results could be significantly affected by risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability and changes of laws affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions, working conditions, rates of exchange, exchange control, exploration licensing, production leasing, petroleum and export licensing and export duties, government control over domestic oil and gas pricing, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds, the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where Valeura currently operates, and difficulties in enforcing Valeura's rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations. Problems may also arise due to the quality or failure of equipment or technical support, which could result in failure to achieve expected target dates for exploration and development operations or result in a requirement for greater expenditure. Valeura will operate in such a manner as to minimize and mitigate its exposure to these risks. However, there can be no assurance that Valeura will be successful in protecting itself from the impact of all of these risks and the related financial consequences.

Acts of Violence, Terrorist Attacks or Civil Unrest in Turkey

During the 2014 to 2016 period, Turkey experienced increased periods of political unrest and civil disobedience primarily associated with the Syrian civil war on its border, the large influx of Syrian refugees to Turkey, the movement of Kurdish fighters from Turkey into Syria and the end of a truce in mid-2015 between the PKK and the Turkish government. More recently, suicide bomb attacks in Ankara and Istanbul have increased security concerns in Turkey. Also, the shooting down by the Turkish military of a Russian jet fighter in November 2015 engaged in the Syrian civil war and purported to have entered Turkish air space has increased tensions between Russia and Turkey and its NATO allies. In July 2016, Turkey experienced an attempted military coup, which quickly failed. In the aftermath of the coup, the military perpetrators were arrested as well as thousands of other citizens suspected of being followers of the exiled Muslim cleric Fethullah Gulen. These events have resulted in a further devaluation of the TL, which has negatively impacted the Company's natural gas revenues from the country (revenues denominated in TL).

To date, the above events have not impacted the Company's ability to conduct operated and non-operated drilling and production operations in the Thrace Basin and no significant delays or security issues have been experienced in these operations. All of the Company's current operated and non-operated operations are in the Thrace Basin of northwest Turkey, more than 1,000 kilometres from the Syrian border.

In the future, access to some operating locations in Turkey may be precluded and Valeura may incur substantial costs to maintain the safety of personnel and operations. Despite these precautions, the safety of operator personnel or Valeura personnel in these locations may be at risk, and Valeura may in the future suffer loss of personnel and disruption of operations, any of which could have a material adverse effect on Valeura's business and results of operations.

Variations in Foreign Exchange Rates and Interest Rates

The Company's drilling operations in Turkey and related contracts are based in U.S. Dollars. Material increases in the value of the U.S. dollar will negatively impact the Company's costs of drilling and completions activity. Future Canadian Dollar/U.S. dollar and Canadian Dollar/TL exchange rates could impact the future value of the Company's reserves as determined by independent evaluators. The Company's functional currency in its subsidiary operations in Turkey is TL. The revenue stream in Turkey is based on TL revenue for natural gas and U.S. dollar based revenue for crude oil translated into TL. The majority of costs will be incurred in U.S. Dollars for capital expenditures and TL for operating expenditures. Decreases in the value of the TL could result in decreases in revenue. Increases in the value of the TL and U.S. dollar could result in increases in the cost of operations. To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract. Valeura continues to assess its exposure to all foreign currencies. Recent volatility and weakness in the value of the TL may impair the ability of the Company to manage this exposure. Further devaluation of the TL without a corresponding increase in the natural gas reference price will result in continued decreases in funds flow from operations and will affect the ability of the Company to meet its financial obligations.

Price Volatility, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Valeura will be affected by numerous factors beyond its control. Valeura's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Valeura may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Valeura's revenues, profitability, future growth and the carrying value of its oil and gas properties, provided such properties yield production, are substantially dependent on prevailing prices of oil and gas. Valeura's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of Valeura. These factors include economic conditions in the United States, Canada, and Turkey, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, and political instability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. In Turkey, natural gas prices for domestic sales are effectively set by the government, which are indirectly affected by these market forces. Any substantial and extended decline in the price of oil and gas would have an adverse effect on Valeura's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The exchange rate between the Canadian dollar, U.S. dollar and TL also affects the profitability of Valeura. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value.

Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. Currently, the Company has no debt facilities in place. However, any bank borrowings available to Valeura in the future will in part be determined by Valeura's borrowing base. A sustained material decline in prices from historical average prices could reduce Valeura's borrowing base, therefore reducing the bank credit available to the Company and require that a portion, or all, of Valeura's bank debt, if any, be repaid.

Failure to Realize Anticipated Benefits of the TBNG Acquisition and other Acquisitions and Dispositions

On February 24, 2017, the Company closed the TBNG Acquisition and continues to evaluate other acquisitions of businesses and assets in the ordinary course of business. Achieving the benefits of the TBNG Acquisition and other acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Valeura. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. In the case where the acquired businesses are non-operated, the Company will need to rely on the operator to achieve the foregoing benefits and the Company's ability to influence the operator's activities in this regard. Management continually assesses the value and contribution of services provided and assets required to provide such services. Accordingly, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Government Rules and Regulations

Valeura's operations are subject to various levels of government controls and regulations in the countries where it operates. Oil and gas exploration and production is a sensitive political issue and as a result there is a relatively higher risk of direct government intervention in respect of laws and regulations that can affect the property rights and title to Valeura's assets in Turkey. Such intervention can extend, in certain jurisdictions, to nationalization, expropriation or other actions that effectively deprive companies of their assets.

Existing laws and regulations include matters relating to land tenure, drilling, production practices including hydraulic fracturing of wells, environmental protection, agricultural land use, marketing and pricing policies, royalties, various taxes and levies including income tax, foreign trade and investment and government approval of lease and licence transfers and other regulatory approvals that are subject to change from time to time. Current legislation is generally a matter of public record and Valeura cannot predict what additional legislation or amendments may be proposed that will affect Valeura's operations or when any such proposals, if enacted, might become effective. There is no certainty regarding obtaining government approvals. Changes in government policy or laws and regulations could adversely affect Valeura's results of operations and financial condition. In particular, a number of changes in the land tenure regulations associated with the New Petroleum Law are in the early years of implementation and the full effect of these changes remain uncertain. Failure to comply with applicable laws, regulations and legal requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions which could have an adverse effect on Valeura's business, financial condition or operations.

Management of Key Relationships in Turkey

Failure to manage relationships with local communities, government and non-government organizations could adversely impact Valeura's business in Turkey. Negative community reaction to operations could have an adverse impact on profitability, the ability to finance or even the viability of Valeura in Turkey. This reaction could lead to disputes that may damage the Company's reputation and could lead to potential disruption of projects or operations.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Valeura will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Valeura may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Valeura's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. No assurance can be given that Valeura will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Valeura may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Valeura.

While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, natural declines as reserves are depleted and production or sales delays cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, Valeura will not be fully insured against all of these risks, nor are all such risks insurable. Although Valeura will maintain liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Valeura could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. In particular, formation pressures have been shown to be elevated below approximately 2,500 metres on the Banarli Licences and West Thrace lands requiring specialized equipment in drilling and completion operations. There is uncertainty regarding the sustainability of initial production rates and decline rates thereafter, and management believes that new shallow gas wells and new fraced tight gas wells will exhibit relatively high decline rates at 50% and 75%, or more, respectively, in their first year of production. There are also risks and uncertainty regarding the Company's ability to address technical drilling challenges and manage water production. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of regulations in foreign jurisdictions where Valeura operates. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. Currently, there are no restrictions on the hydraulic fracturing of wells in Turkey. However a number of jurisdictions in Europe have temporarily or permanently banned hydraulic fracturing of wells and there is a risk that these restrictions may spread to other jurisdictions in the region including Turkey. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Valeura to incur costs to remedy such discharge. Although Valeura believes it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws or agricultural land use requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Valeura's financial condition, results of operations or prospects.

Substantial Capital Requirements

Valeura anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If its revenues or reserves decline, it may have limited ability to acquire or expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Valeura. The potential inability of Valeura to access sufficient capital for its operations could have a material adverse effect on Valeura's financial condition, results of operations or prospects.

Additional Funding Requirements

Valeura's cash flow from its reserves, once developed, may not be sufficient to fund its ongoing activities at all times. From time to time, Valeura may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Valeura to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Valeura's revenues from its reserves, once developed, decrease as a result of lower oil and natural gas prices or otherwise, it will affect Valeura's ability to expend the necessary capital to replace its reserves or to maintain its production. If cash flow from operations is not sufficient for Valeura to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Valeura.

Issuance of Debt

From time to time Valeura may enter into transactions to acquire assets or the shares of other entities. In the early stages of growth, Valeura may have difficulty accessing debt needed to acquire and develop international oil and gas properties. This may result in the inability of Valeura to complete certain acquisitions or drilling activities. Future acquisitions may be financed partially or wholly with debt, which may increase debt levels above industry standards. Depending on future exploration and development plans, Valeura may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Valeura's articles nor its by-laws limit the amount of indebtedness that it may incur. The level of Valeura's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time Valeura may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Valeura will not benefit from such increases and may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Given that Valeura's natural gas sales and revenues in Turkey are priced in TL, Valeura from time to time may enter into agreements to fix the exchange rate of Canadian or United States dollars to the TL in order to offset the risk of revenue losses. Valeura may similarly seek to fix the exchange rate between the TL and the Canadian or U.S. dollar to offset the risk of a relative strengthening of the U.S. dollar, which is the currency basis for large portion of the capital expenditures in Turkey.

Availability of Drilling, Hydraulic Fracturing and Other Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling, hydraulic fracturing and other related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Valeura and may delay exploration and development activities. To the extent it is not the operator of its oil and gas properties, Valeura will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. While it is the practice of Valeura, in acquiring significant oil and gas leases or interest in oil and gas leases to fully examine the title to the interest under the lease, this should not be construed as a guarantee of title. There may be title defects that affect lands comprising a portion of Valeura's properties. To the extent title defects do exist, it is possible that Valeura may lose all or a portion of its right, title, estate and interest in and to the properties to which the title relates.

Competition

Oil and gas exploration is intensely competitive in all its phases and involves a high degree of uncertainty with respect to the impact of such competition. Valeura will compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Valeura. Valeura's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire suitable producing properties or acquire new exploration licences. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Valeura may also be subject to competition from the alternative fuel industry or fuel substitution by its customers

Reserves Are Estimates Only

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and future net revenue to be derived therefrom, including many factors beyond the control of Valeura. The reserves and future net revenue information set forth herein represents estimates only.

The reserves and estimated future net revenue from Valeura's Turkish properties have been independently evaluated by D&M and are contained in the D&M Reserves Report as at December 31, 2016. The report includes a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil, natural gas liquids and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on the respective price forecasts in use at the effective date of the D&M Reserves Report and many of these assumptions are subject to change and are beyond the control of Valeura. Actual production and future net revenue derived therefrom will vary from these evaluations, and such variations could be material. The present value of estimated future net revenue referred to herein should not be construed as the current market value of estimated crude oil, natural gas liquids and natural gas reserves attributable to Valeura's properties. The estimated discounted future net revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Depletion of Reserves and Production Declines

Valeura's oil and natural gas reserves and production, and therefore its cash flows and earnings, will be highly dependent upon Valeura developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration and development activities or acquisition, Valeura's reserves and production will naturally decline over time as reserves are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, Valeura's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that Valeura will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs, or that Valeura will be able to convert its contingent resources to reserves.

Insurance

Valeura's involvement in the exploration for and development of oil and natural gas properties may result in it becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Valeura carries insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, Valeura may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Valeura. The occurrence of a significant event that Valeura is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Valeura's financial position, results of operations or prospects.

Management of Growth

Valeura may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Valeura to manage growth effectively, including the integration of TBNG and other acquired assets or companies, will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The potential inability of Valeura to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Permits, Licences and Leases

Valeura's properties will be held in the form of permits, licences and leases and working interests in permits, licences and leases. If Valeura or the holder of the permit, licence or lease fails to meet the specific requirement of a permit, licence or lease, the permit, licence or lease may terminate or expire (excluding those which may be voluntarily relinquished by the Company). While Valeura monitors the status and expiry of all of its current licences and leases, all of which are in Turkey, there can be no assurance that any of the obligations required to maintain such licences or leases will be met. The termination or expiration of any of its licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Valeura's results of operations and business. To the extent such permits, licences and leases are subsequently suspended or revoked, Valeura may be curtailed or prohibited from proceeding with planned exploration, development or operation of its projects. Failure to comply with permitting and legal requirements may result in enforcement actions, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions which could have an adverse effect on Valeura's business, financial condition or operations.

Internal Controls Over Financial Reporting

Valeura has established internal controls over financial reporting ("**ICFR**") which include policies and procedures that pertain to the maintenance of financial records, the preparation of accurate financial statements, controls over bank accounts and the prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets or funds. Valeura has delegation of authority policies approved by the respective boards of directors of the parent company and each subsidiary, which policies delineate how various corporate and financial matters must be approved and the authority levels of management and employees (including in-country managers in Turkey). Valeura has the right and periodically conducts audits of the records and expenditures of its operating partners. While management has determined that Valeura maintains effective ICFR, Valeura cannot be certain errors or failures will not occur related to financial processes and reporting. Failure to properly implement existing controls, or difficulties encountered in their implementation, could impact the Company's results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's financial statements and reduce the trading price of the Common Shares.

At the operational level in Turkey, the Company relies upon certain local managers and employees and its operating partners. A large portion of the business and contracts in Turkey are in the Turkish language and the Company must rely on certain key personnel in-country who work in the Turkish language and report to management. A major disruption in the flow of information, or obtaining inaccurate information from these local employees and partners, could adversely impact the accuracy of financial reporting and management information.

Internal Controls and Procedures Over Anti-Corruption Requirements

Valeura has established a Code of Business Conduct and Ethics which includes policies and procedures covering anti-bribery and anti-corruption of foreign public officials, including regular reporting to management and the Board. While management believes these policies are adequate, and despite careful establishment and implementation, there can be no assurance that these or other anti-bribery or anti-corruption policies and procedures are or will be sufficient to protect against corrupt activity. In particular, Valeura, in spite of its best efforts, may not always be able to prevent or detect corrupt practices by employees, or third parties, such as sub-contractors or its operating partners, which may result in reputational damage, civil and/or criminal liability being imposed on Valeura, which could have an adverse effect on Valeura's business, financial condition or operations.

Seasonality

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in demand for the goods and services of Valeura. In Turkey, the wet weather in the winter months of the year can require delays in operations.

Counterparty Risk

Valeura may be exposed to counterparty risk through its contractual arrangements with current or future joint venture partners, farm-in partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on Valeura and its cash flow from operations.

Conflicts of Interest

The directors or officers of Valeura may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with Valeura. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a company who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with Valeura to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Specialized Skill and Knowledge

International exploration and development activities such as those the Company is engaged in require specialized skills and knowledge in the areas of petroleum engineering, geology, geophysics and drilling. In addition, specific knowledge and expertise relating to local laws (including regulations relating to land tenure, exploration, development, production, marketing, transportation, the environment, royalties and taxation) and market conditions is required to compete with other international oil and gas entities.

Reliance on Key Personnel

The success of Valeura will depend in large measure on certain key personnel and management. The Company also relies on certain key personnel in-country with the ability to work in the Turkish language and report to management in Canada. The loss of the services of such key personnel could have a material adverse effect on Valeura. Valeura does not have key person insurance in effect for members of management. The competition for qualified personnel in the oil and natural gas industry, particularly the international oil and gas industry in which Valeura operates, can be intense and there can be no assurance that Valeura will be able to attract and retain all personnel necessary for the development and operation of its business.

Shareholders must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Valeura.

Transportation Costs

Disruption in or increased costs of transportation services could make oil and natural gas a less competitive source of energy or could make Valeura’s oil and natural gas less competitive than other sources. The industry depends on pipeline facilities, rail, trucking, ocean-going vessels and barge transportation to deliver shipments, and transportation costs are a significant component of the total cost of supplying oil and natural gas. Disruptions of these transportation services because of weather related problems, strikes, lockouts, terrorist activities, delays or other events could temporarily impair the ability to supply oil and natural gas to customers and may result in lost sales. In addition, increases in transportation costs, or changes in transportation costs for oil and natural gas produced by competitors, could adversely affect profitability. To the extent such increases are sustained, Valeura could experience losses and may decide to discontinue certain operations forcing Valeura to incur closure and/or care and maintenance costs, as the case may be. Additionally, lack of access to transportation may hinder the expansion of production at some of Valeura’s properties and Valeura may be required to use more expensive transportation alternatives.

Disruptions in Production

Other factors affecting the production and sale of oil and natural gas that could result in decreases in profitability include: (i) expiration or termination of permits, licences or leases, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labour difficulties; (v) worker vacation schedules and related maintenance activities; and (vi) changes in the market and general economic conditions. Weather conditions, equipment replacement or repair, fires, amounts of rock and other natural materials and other geological conditions can have a significant impact on operating results.

Reliance on Industry Partners

To the extent Valeura is not the operator of its oil and gas properties, Valeura will be dependent on such operators for the timing of activities related to such properties, subject to any influence Valeura can bring to bear in operating committee and technical committee meetings under joint venture agreements or other regular communications, and will largely be unable to direct or control the activities of the operators. The ability of Valeura management to influence other operators, as necessary, to protect its interests will be an important determinant of success. By virtue of the TBNG Acquisition in early 2017, Valeura has taken over the operatorship of the TBNG JV which will significantly increase the Company’s level of control of its business in Turkey.

Dilution

Valeura may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Valeura which may be dilutive.

Income Taxes

Valeura has filed, and will file, all required income tax returns. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of Valeura, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

INDUSTRY CONDITIONS

Turkey

The oil and natural gas industry in Turkey is subject to controls and regulations governing its operations imposed by legislation enacted by the Turkish governments and with respect to pricing and taxation of oil and natural gas by agreements, all of which should be carefully considered by investors in the oil and gas industry. The Company's activities are affected in varying degrees by government regulations relating to the oil and gas industry and foreign investment. Operations may be affected in varying degrees by government regulations with respect to price controls, export controls, income taxes, value-added taxes, expropriation of property, production restrictions and environmental legislation. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size operating in Turkey. Outlined below are some of the principal aspects of the legislation, regulations and agreements governing the oil and gas industry in Turkey.

After extensive review and significant input from industry, the Turkish government adopted the New Petroleum Law to replace the Old Petroleum Law on June 30, 2013. The most significant changes as described below relate to land tenure regulations.

Commercial Terms

Turkey's fiscal regime for oil and gas operations is presently comprised of royalties and income tax. Royalties are at 12.5% and the corporate income tax rate is 20%. Additionally, a 15% withholding tax is applied on dividends to be distributed to foreign entities. However, the withholding tax may be reduced to 10% depending on the bilateral treaties signed between Turkey and the home country of the petroleum rights holder in Turkey.

Under the New Petroleum Law, the government royalty rate remains unchanged at 12.5%. Also, there are no changes in taxation regulations with respect to the petroleum industry.

Land Tenure Regime - Old Petroleum Law

All of the Company's original licences and leases acquired in Turkey through acquisitions or by application over the 2010 to 2013 period were issued under the Old Petroleum Law. Under the Old Petroleum Law, the following regulations applied.

The GDPA, the agency responsible for the regulation of oil and gas activities in Turkey, awarded a licence after it approved the applicant's work program, which could include obligations such as geological and geophysical work, seismic acquisition and drilling of wells.

Petroleum exploration licences had an initial four-year term. Licences could be extended in certain circumstances for two additional two-year terms for a total licence term of eight years. If, at the end of the eighth year, a producible discovery was confirmed or an exploration well was spudded by that time which ultimately resulted in a discovery, the term of the licence could be extended for a further three years (discovery extension) for a total term up to 11 years to explore and appraise the licence prior to applying for a lease(s) on discovered reserves at the end of the 11th year at the latest. The Old Petroleum Law stipulated the statutory drilling obligation. Before the end of the third year of the oldest licence in any district, the first well would need to be spudded. This obligation could be extended for one year upon a bank guarantee. Following the rig release of the first well, the licence holder would need to spud a well every six months (could be extended for another six months) from rig release of the previous well or from rig release of the completion of the previous well in any licence in the same district. In the case where a company held more than one licence in a district, the company could group the licences. In this case one well would satisfy the district drilling obligation for all the grouped licences.

A licence grants exclusive rights over an area for the exploration for petroleum. Under the Old Petroleum Law, a company could own up to eight licences (on the basis of a 100% working interest) or up to 400,000 hectares of net land within a designated petroleum district, whichever was applicable. Rentals were due annually based on the hectares under the licence.

Under the Old Petroleum Law, if a discovery was made the licence holder could produce oil and gas during the remaining term in the licence, and at any time up to the end of the eighth year of the licence, could apply to extend the land tenure in the form of a production lease at a reduced areal extent, not to exceed the greater of one-half of the licence or 25,000 hectares. Under a lease, the lessee could continue to develop the lease area and produce oil and gas. Leases were generally granted for an initial term of 20 years and could be renewed upon application for two additional 10-year periods. Annual rentals were due based on the number of hectares comprising the lease. The 20-year lease period was calculated from the start of any discovery extension (i.e. the end of the eighth year at the latest).

Land Tenure Regime - New Petroleum Law

Under the New Petroleum Law restrictions on the maximum area that can be held under exploration licences within each petroleum district have been eliminated coincident with the consolidation of 18 onshore districts into a single district. This could facilitate consolidation of landholdings in certain areas such as the Thrace Basin.

Future exploration licence awards will require the posting of a bond of up to 2% of the work program for the initial term or any subsequent extensions (no bonds were required under the Old Petroleum Law). The initial term of new licences will be five years (four years under the Old Petroleum Law). Exploration licences can be extended up to 11 years (two, two-year extensions plus a two-year discovery extension) prior to carving-out one or more production leases and relinquishing other land (total of 11 years, unchanged from the Old Petroleum Law), provided a discovery is made by the end of the ninth year (eighth year under the Old Petroleum Law).

The restriction with respect to the size of a production lease under the Old Petroleum Law has been eliminated. However, some uncertainty remains in the tenure of new leases. The recent practice of the GDPA in awarding new leases over the 2014 to 2016 period to the Company and its partners in the Thrace Basin is to set the initial term for varying periods ranging from five years to 14 years, depending on the expected reserve life, amongst other factors, potentially extendable up to 40 years if the expected reserve life supports such an extension.

The GDPA also adopted a new international grid system associated with the New Petroleum Law and indicated its intent to realign all eligible "old" licences to the new grid system. Also the GDPA indicated that any new licence or lease awards would also be aligned to the new grid system. Voluntary conversion of "old" licences to "new" licences was encouraged by the GDPA in certain circumstances depending on the age of the licence (within its first six years), which would also require realignment of the licence boundaries to the new international grid system. In implementing such conversions, it was expected that negotiations between adjacent licence holders and the GDPA would be required and that such negotiations may not be attainable in the required timeframe.

Under the conversion rules, old licences could be retained in their existing configuration but the maximum possible term of these licences would be reduced from 11 years to eight years (i.e. four-year initial term, one two-year extension and a final two-year discovery extension if a discovery is made before the end of the sixth year).

The GDPA initiated the conversion process in 2014 and as of the date hereof, all of the Company's old licences have been converted to new licences or leases covering part of the old licences. Also some licences have expired in the normal course and the TBNG JV has submitted several applications to the GDPA for new licences and leases covering part of these expired licences. Also, Valeura has submitted applications for two new licences in the Thrace Basin. All of the applications related to leases have been approved as of the date hereof but the new licence applications remain under review by the GDPA.

Environmental

The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which the Company operates. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of oil and natural gas and various substances produced concurrently with oil and natural gas. 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. Valeura is committed to complying with environmental and operation legislation wherever the Company operates.

Pipeline Infrastructure

BOTAS owns and operates the national crude oil pipeline grid and the national natural gas pipeline grid in Turkey.

With regard to major natural gas pipelines, BOTAS owns and operates the national gas grid which connects essentially all the major population centres and is within easy access to the Company's existing and planned operations in the Thrace Basin of northwest Turkey. At the end of 2010, the BOTAS natural gas pipeline network consisted of 11,593 kilometres of various pipelines sizes from 10-inch to 48-inch diameter.

With regard to major crude oil pipelines, BOTAS owns and operates the following infrastructure: the 18-inch Batman to Dortyol crude oil pipeline, which services the prevalent crude oil producing areas of the southeast Anatolia region; the 24-inch Ceyhan to Kirikkale crude oil pipeline, which supplies mainly imported crude oil to the Kirikkale refinery east of Ankara; and the Turkey portion of the twin 40-inch and 46-inch Kirkuk to Ceyhan oil pipeline delivering Iraqi crude oil to the port city of Ceyhan for export. It also operates the Turkish portion of the Baku to Tbilisi to Ceyhan crude oil pipeline delivering Azeri crude oil to Ceyhan for export.

Pricing and Marketing

Turkey imports approximately 99% of its natural gas and 92% of its crude oil energy needs and as such any new domestic production has a ready market. Consequently, the Company does not foresee any major concern with the marketing of crude oil or natural gas from its operations.

Crude oil pricing in Turkey is determined under the Petroleum Market Law No. 5015 (Gazetted on December 12, 2003). The pricing for the sales of crude oil is established according to the nearest accessible global free market condition. The domestic crude oil price is linked to world market factors with the base market price being the price at the nearest delivery port. Customary transportation and crude oil quality premiums or deductions, as the case may be, are applied to determine the crude oil price at the custody transfer point. Domestic purchasers and refiners are to give priority to domestic crude oil under the above pricing process.

Total natural gas demand in Turkey in 2015 was approximately 4.65 Bcf/d. BOTAS is the major importer and distributor of natural gas in Turkey. Although some import contracts have been released to private operators, BOTAS currently controls approximately 80% of Turkey's natural gas imports. Given the very small domestic production of approximately 0.07 Bcf/d, there is a robust market for additional domestic natural gas production. Due to the dominance of BOTAS in the natural gas market in Turkey, the BOTAS pricing structure effectively sets the domestic market price. In 2015, Russia supplied approximately 56% of Turkey's natural gas imports followed by Iran at 16%, Azerbaijan at 11%, LNG from Algeria, Qatar and Nigeria at 16% and spot and other at 1%. Accordingly the BOTAS cost tracks world reference pricing and in turn indirectly influences the price available to domestic producers, translated into TL, at some discount. BOTAS regularly posts prices in TL and its Level-2 wholesale tariff ("**BOTAS Reference Price**") was reduced by 10% effective October 1, 2016 to 0.704145 TL/m^3. This BOTAS Reference Price (in TL) remains unchanged as of the date hereof and is equivalent to approximately $7.21 per Mcf at a current exchange rate of approximately $1 = 2.75 TL. BOTAS along with a number of other privately owned natural gas distributors in Turkey are expected to be the main potential purchasers of any new domestic natural gas production. The Company expects the BOTAS Reference Price to continue to be indirectly linked to the weighted average cost of imported gas to Turkey and government policy with respect to the level of consumer subsidies, if any.

The Company expects natural gas pricing under its current and future contracts to continue to be at some negotiated discount to the BOTAS Reference Price (0% to 15% discount, dependent on reserve size, the magnitude of daily gas volume deliverable and the nature of the contract). The Company's natural gas production from the TBNG JV lands are purchased by more than 55 local customers directly tied in to the Company's sales gas distribution system at an average discount as of the date hereof of approximately 2% to the BOTAS Reference Price. The Company's natural gas production from the Banarli Licences is currently tied-in to the TBNG JV facilities and is being purchased by the TBNG JV, net of a transportation and marketing fee (of which Valeura receives 40% as a partner in the TBNG JV), resulting in a net discount of approximately 4% from the BOTAS Reference Price.

LEGAL AND REGULATORY PROCEEDINGS

Valeura is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of, any legal proceeding during the year ended December 31, 2016, nor is Valeura aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10 percent of the current assets of Valeura.

During the year ended December 31, 2016, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, officer or principal Shareholder, nor any affiliate or associate of such a person, has or has had any material interest in any transaction or any proposed transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Valeura.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada, at its principal office in Calgary, Alberta, is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

The Company entered into the following material contracts within the most recently completed financial year:

- the Acquisition Agreement;
- the Deep Rights Sale Agreement;
- the underwriting agreement dated October 14, 2016 among the Company, Cormark Securities Inc. and GMP Securities L.P.; and
- the Subscription Receipt Agreement.

See "*General Development of the Business – Three Year History – 2016*".

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by D&M. As at December 31, 2016, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of D&M, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

The auditors of the Company, KPMG LLP, are independent with respect to the Company, in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Proxy Statement and Information Circular of the Company prepared in connection with the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided in the Company's financial statements and management discussion and analysis for the year ended December 31, 2016.

Copies of this Annual Information Form, any interim financial statements of the Company subsequent to the annual financial statements, the Company's Proxy Statement and Information Circular and other additional information relating to the Company are available on SEDAR at www.sedar.com.

APPENDIX A-1 – FORM 51-101F1 – STATEMENT OF RESERVES DATA AND OTHER CRUDE OIL AND CONVENTIONAL NATURAL GAS INFORMATION

FORM 51-101F1

STATEMENT OF RESERVES DATA
AND OTHER OIL AND NATURAL GAS INFORMATION

Valeura Energy Inc. (the "**Company**") engaged DeGolyer and MacNaughton ("**D&M**") to prepare a report relating to the Company's reserves in Turkey as at December 31, 2016. The reserves on the properties in Turkey described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Company's crude oil and conventional natural gas reserves in Turkey are located in the Thrace Basin area of Turkey, which is west of Istanbul. Set out below is a summary of the crude oil and conventional natural gas reserves and the value of future net revenue of the Company as at December 31, 2016 as evaluated by D&M in its report with a preparation date of March 14, 2017 (the "**D&M Reserves Report**"). The pricing used in the forecast price evaluations is set forth in the notes to the tables.

The D&M Reserves Report does not give effect to the TBNG Acquisition.

The D&M Reserves Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the D&M Reserves Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the D&M Reserves Report. The recovery and reserves estimates on the Company's properties described herein are estimates only.

OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS[9]

	Light and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent[10]	
	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (MMcf)	Net[1] (MMcf)	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (Mboe)	Net[1] (Mboe)
Proved Developed Producing[2][5][6]	6	6	-	-	2,782	2,416	-	-	470	409
Proved Developed Non-Producing[2][5][7]	0	0	-	-	2,428	2,108	-	-	405	351
Proved Undeveloped[2][8]	0	0	-	-	4,153	3,593	-	-	692	599
Total Proved[2]	6	6	-	-	9,363	8,117	-	-	1,567	1,359
Total Probable[3]	3	3	-	-	18,803	16,286	-	-	3,137	2,717
Total Proved Plus Probable[2][3]	9	9	-	-	28,166	24,403	-	-	4,704	4,076
Total Possible[4]	5	4	-	-	15,125	13,112	-	-	2,526	2,189
Total Proved Plus Probable Plus Possible[2][3][4]	14	13	-	-	43,291	37,515	-	-	7,230	6,265

NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS(9)(15)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(15) Discounted At				
	0% (M US$)	5% (M US$)	10% (M US$)	15% (M US$)	20% (M US$)	0% (M US$)	5% (M US$)	10% (M US$)	15% (M US$)	20% (M US$)
Proved Developed Producing(2)(5)(6)	8,334	7,551	6,916	6,388	5,939	8,334	7,551	6,916	6,388	5,939
Proved Developed Non-Producing(2)(5)(7)	11,712	7,492	5,112	3,718	2,864	10,290	6,641	4,570	3,348	2,593
Proved Undeveloped(2)(8)	8,088	5,442	3,503	2,079	1,032	6,121	3,891	2,283	1,119	277
Total Proved(2)	28,134	20,485	15,531	12,185	9,835	24,745	18,083	13,769	10,855	8,809
Total Probable(3)	67,329	44,580	30,184	20,911	14,837	54,279	35,951	24,388	16,964	12,113
Total Proved Plus Probable(2)(3)	95,463	65,065	45,715	33,096	24,672	79,024	54,034	38,157	27,819	20,922
Total Possible(4)	75,413	47,162	31,069	21,517	15,607	61,099	38,250	25,316	17,661	12,930
Total Proved Plus Probable Plus Possible(2)(3)(4)	170,876	112,227	76,784	54,613	40,279	140,123	92,284	63,473	45,480	33,852

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS(9)

	Revenue (M US$)	Royalties (M US$)	Operating Costs (M US$)	Development Costs (M US$)	Abandonment and Reclamation Costs (M US$)	Future Net Revenue Before Income Taxes (M US$)	Income Taxes(15) (M US$)	Future Net Revenue After Income Taxes(15) (M US$)
Total Proved(2)	67,089	8,918	9,389	16,384	4,264	28,134	3,389	24,745
Total Proved Plus Probable(2)(3)	214,930	28,721	23,548	61,629	5,568	95,464	16,438	79,025
Total Proved Plus Probable Plus Possible(2)(3)(4)	342,842	45,775	36,951	82,857	6,382	170,877	30,753	140,123

FUTURE NET REVENUE BY PRODUCT TYPE
BASED ON FORECAST PRICES AND COSTS[9]

		Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
	Production Group	**(M US$)**	**US$/boe[10]**	**US$/Mcfe[11]**
Total Proved[2]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	15,531	11.43	1.91
Total Proved[2]		**15,531**	**11.43**	**1.91**
Probable[3]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	30,184	11.11	1.85
Total Probable[3]		**30,184**	**11.11**	**1.85**
Total Proved Plus Probable[2][3]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	45,715	11.22	1.87
Total Proved Plus Probable[2][3]		**45,715**	**11.22**	**1.87**
Possible[4]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	31,069	14.19	2.37
Total Possible[4]		**31,069**	**14.19**	**2.37**
Total Proved Plus Probable Plus Possible[2][3][4]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	76,784	12.26	2.04
Total Proved Plus Probable Plus Possible[2][3][4]		**76,784**	**12.26**	**2.04**

The pricing assumptions used in the D&M Reserves Report with respect to net present values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth below.

FORECAST PRICES & COST ESCALATION RATES USED IN D&M RESERVES REPORT[9]

	Conventional Natural Gas		Light and Medium Crude Oil		Cost Escalation
Year	**TBNG (US$/Mcf)**	**Banarli (US$/Mcf)**	**TBNG (US$/bbl)**	**Banarli (US$/bbl)**	**%/year**
2017	6.11	5.99	42.15	42.15	2.0
2018	6.33	6.20	45.27	45.27	2.0
2019	6.57	6.43	48.50	48.50	2.0
2020	6.83	6.69	52.64	52.64	2.0
2021	7.11	6.96	55.31	55.31	2.0
2022	7.43	7.28	56.42	56.42	2.0
2023	7.77	7.61	58.39	58.39	2.0
2024	8.24	8.07	61.28	61.28	2.0
2025	8.73	8.55	64.26	64.26	2.0
2026	8.90	8.72	65.55	65.55	2.0
2027	9.08	8.89	66.86	66.86	2.0
2028	9.26	9.07	68.20	68.20	2.0
2029+	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter

The Company's weighted average historical prices in Turkey for the year ended December 31, 2016 were:

Conventional Natural Gas ($/Mcf)	**Light and Medium Crude Oil ($/bbl)**	**Natural Gas Liquids ($/bbl)**
9.20	55.88	Not Applicable

RECONCILIATION OF THE COMPANY'S GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS [9]

The following table sets forth a reconciliation of the changes in the Company's working interest, before royalties, of light and medium crude oil, heavy crude oil, conventional natural gas, natural gas liquids and oil equivalent reserves as at December 31, 2016 against such reserves as at December 31, 2015 based on the forecast price and cost assumptions set forth in Note 9:

	Light and Medium Crude Oil					Heavy Crude Oil				
	Gross Proved (Mbbl)	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Possible (Mbbl)**	**Gross Proved Plus Probable Plus Possible (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Possible (Mbbl)**	**Gross Proved Plus Probable Plus Possible (Mbbl)**
At December 31, 2015	79	51	130	78	208	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0
Technical Revisions	-70	-48	-118	-73	-191	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0
Production	3	0	3	0	3	0	0	0	0	0
At December 31, 2016	6	3	9	5	14	0	0	0	0	0

	Conventional Natural Gas					Natural Gas Liquids				
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Possible (MMcf)	Gross Proved Plus Probable Plus Possible (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)
At December 31, 2015	10,486	21,499	31,985	18,257	50,242	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0
Technical Revisions	613	-2,696	-2,083	-3,132	-5,215	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0
Production	1,736	0	1,736	0	1,736	0	0	0	0	0
At December 31, 2016	9,363	18,803	28,166	15,125	43,291	0	0	0	0	0

	Oil Equivalent[(10)(17)]				
	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Possible (Mboe)	Gross Proved Plus Probable Plus Possible (Mboe)
At December 31, 2015	1,827	3,634	5,461	3,121	8,582
Extensions	0	0	0	0	0
Improved Recovery	0	0	0	0	0
Technical Revisions	32	-497	-465	-595	-1,060
Discoveries	0	0	0	0	0
Acquisitions	0	0	0	0	0
Dispositions	0	0	0	0	0
Economic Factors	0	0	0	0	0
Production	292	0	292	0	292
At December 31, 2016	1,567	3,137	4,704	2,526	7,230

Notes:

(1) "**Gross Reserves**" are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company. "**Net Reserves**" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.

(2) "**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "**Possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "**Developed**" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

(6) "**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(7) "**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(8) "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(9) The pricing assumptions used in the D&M Reserves Report with respect to net values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth in the preceding table titled "Forecast Prices & Cost Escalation Rates Used in D&M Reserves Report". The Forecast Prices & Cost Escalation rates were developed by D&M as at December 31, 2016 and reflect the then current year forecast prices and cost escalation rates. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(10) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(11) "**Mcfe**" means thousand cubic feet of sales gas equivalent derived by converting oil to gas in the ratio of one barrel of oil to six thousand cubic feet of gas. Mcfes may be misleading, particularly if used in isolation. A Mcfe conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(12) Including solution gas and other by-products associated with oil production.

(13) Including non-associated gas by-products but excluding solution gas.

(14) Reference to M US$, US$/bbl, US$/Mcf, US$/boe and US$/Mcfe are stated in United States dollars. Reference to M$, $/bbl, $/Mcf, $/boe and $/Mcfe are stated in Canadian dollars.

(15) Income taxes are Turkey income taxes.

(16) The D&M Reserves Report categorizes all production as natural gas as the primary phase.

(17) Values may not add due to rounding.

Proved Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed for each of the Company's product types in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent[1] (Mboe)
December 31, 2014	0	0	1,704	0	284
December 31, 2015	0	0	855	0	143
December 31, 2016	0	0	0	0	0

Note:

(1) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the D&M Reserve Report as of December 31, 2016, there are no assigned proved undeveloped reserves first attributed in 2016.

In the D&M Reserve Report as of December 31, 2016, there are a total of 18 Proved Undeveloped locations assigned reserves. The Company continually evaluates its capital program to maximize its opportunities and any well that ultimately is drilled may or may not correspond exactly to the well location quoted in the D&M Reserves Report as each actual drilled well is dependent on new information and ongoing technical and economic review. The Company has budgeted six to eight wells in 2017 on lands associated with and in close proximity to the 18 wells assigned proved undeveloped reserves, and while the Company has not set budgets for the year 2018 and beyond, if similar levels of yearly drilling activity continued beyond 2017, development of the assigned Proved Undeveloped Reserves, in the majority of cases, can be expected to occur within the next three to four years, subject to a number of contingencies including partner and regulatory approvals, availability of equipment, product pricing, currency exchange rates, well performance and availability of financing in the future.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves that were first attributed for each of the Company's product types in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent[(1)] (Mboe)
December 31, 2014	0	0	11,187	0	1,865
December 31, 2015	2	0	3,044	0	509
December 31, 2016	0	0	0	0	0

Note:

(1) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the D&M Reserve Report as of December 31, 2016, there are no assigned probable undeveloped reserves first attributed in 2016.

In the D&M Reserve Report as of December 31, 2016, there are a total of 54 drilling locations assigned probable undeveloped reserves. The Company continually evaluates its capital program to maximize its opportunities and any well that ultimately is drilled may or may not correspond exactly to the well location quoted in the D&M Reserves Report as each actual drilled well is dependent on new information and ongoing technical and economic review. The Company has budgeted six to eight wells in 2017 on lands associated with and in close proximity to the 54 wells assigned probable undeveloped reserves, and while the Company has not set budgets for the year 2018 and beyond, if similar or increased levels of yearly drilling activity continued beyond 2017, development of the assigned probable undeveloped reserves, in the majority of cases, can be expected to occur within the next six to nine years, subject to a number of contingencies including partner and regulatory approvals, availability of equipment, product pricing, currency exchange rates, well performance and availability of financing in the future.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices, currency exchange rates and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of future net revenue there from. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effect of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, currency exchange rates, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in forecast prices, currency exchange rates, reservoir performance and geological conditions or production. These revisions can be either positive or negative. While we do not anticipate any significant economic factors or significant uncertainties will affect any particular component of the reserve data, the reserves can be affected significantly by fluctuations in product pricing, currency exchange rates, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

Future Development Costs

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the D&M Reserves Report:

	Total Proved(1) Estimated Using Forecast Prices and Costs (M US$)	Total Proved(1) Plus Probable(2) Estimated Using Forecast Prices and Costs (M US$)
2017	2,473	4,293
2018	7,220	8,689
2019	5,015	5,331
2020	917	11,104
2021	227	19,278
Remainder	533	12,934
Total for all years undiscounted	16,385	61,629

Notes:

(1) "**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(2) "**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The Company's primary source of liquidity to fund its estimated future development costs, as outlined in the above table, is derived from the Company's internally-generated cash flow, debt financing when deemed appropriate and new equity issues if made on favourable terms.

Oil and Gas Properties and Wells

The Company's major properties are the TBNG JV lands and Banarli Licences both situated in the Thrace Basin. The Company also holds interests in minor properties including three production leases at Edirne in the Thrace Basin and two exploration licences at Gaziantep in the Anatolian Basin. In total the Company's land holdings as of December 31, 2016 comprised an onshore area of approximately 984 gross sections (482 net sections) all in Turkey. All of the Company's 2016 production was from the Thrace Basin.

As of December 31, 2016, the TBNG JV lands entailed 12 production leases and two exploration licences comprising an onshore area of approximately 459 gross sections (184 net sections). All development is onshore and a small percentage of the acreage is developed. Seven of the 12 production leases and both of the exploration licences on the TBNG JV lands are new production leases and exploration licences that were converted under the New Petroleum Law.

As of December 31, 2016, the Banarli lands entailed two exploration licences comprising an onshore area of approximately 209 gross sections (209 net sections) These two Banarli Licences are new exploration licences that were converted under the New Petroleum Law.

In 2014, the expiring Edirne exploration licence 3839 was converted to three new production leases totaling approximately 78 gross sections (27 net sections) under provisions of the New Petroleum Law. Also Gaziantep exploration licence 4607 was converted to two new exploration licences in 2014 under the New Petroleum Law comprising approximately 238 gross sections (62 net sections). Subsequent to year ending December 31, 2016, the Gaziantep lands (Anatolian Basin lands) were relinquished in January 2017, see "*Properties with No Attributed Reserves*".

The natural gas produced in the Thrace Basin has a high methane content and is relatively dry with a low water to gas ratio which currently only requires dehydration and compression to meet sales requirements. The Company has an extensive gas gathering network which gathers all the production to a central dehydration and compression facility. Processed natural gas is delivered through a TBNG JV owned distribution network to 55 customers within a 50 kilometres distance of TBNG JV's central processing facility.

A listing of the Company's wells in Turkey as of December 31, 2016 is shown below:

	Oil Wells		Natural Gas Wells		Standing & Other Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Producing	1	0.40	88	36.40	0	0.00
Non-producing	1	0.26	131	52.50	20	7.86
Total	2	0.66	219	88.90	20	7.86

Notes:

(1) "**Gross Wells**" are the total number of wells in which the Company has an interest.

(2) "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

Properties with No Attributed Reserves

The following table sets out the Company's undeveloped land position in Turkey effective December 31, 2016:

	Undeveloped Acreage	
	Gross(1)	Net(2)
Thrace Basin	465,255	263,854
Anatolian Basin	151,636	39,425
Total	616,891	303,280

Notes:

(1) "**Gross**" means the total number of acres in which the Company has a working interest.

(2) "**Net**" means the number of acres obtained by aggregating the Company's working interest in each of its acreage positions.

Subsequent to year end 2016 the following transactions have affected the Company's undeveloped acreage as follows:

January 6, 2017 – The Company closed the West Thrace Deep Rights Sale. The West Thrace Deep Rights Sale has no effect on the Company's gross undeveloped acres or net undeveloped acreage in the Company's shallow rights (2,500 metres and shallower) and reduces the Company's net undeveloped acreage in the Company's deep rights (2,500 metres and deeper) by 69,365 net acres.

January 17, 2017 – The Gaziantep licences were relinquished, which reduces the Company's gross and net undeveloped acreage by 151,636 acres and 39,425 acres, respectively.

February 2, 2017 – The TBNG JV was awarded two exploration licences, which increases the Company's gross and net undeveloped acreage by 50,360 acres and 20,144 acres, respectively.

February 24, 2017 – The Company closed the TBNG Acquisition. The TBNG Acquisition has no effect on the Company's gross undeveloped acres, increases the Company's net undeveloped acreage in the Company's shallow rights (2,500 metres and shallower) by 138,326 net acres, and increases the Company's net undeveloped acreage in the Company's deep rights (2,500 metres and deeper) by 138,933 net acres.

The overall effect of the subsequent events on the Company's undeveloped acreage is to:

- reduce the gross undeveloped acreage to 515,615 gross acres;
- increase the net undeveloped acreage in the shallow rights (2,500 metres and shallower) to 422,324 net acres; and
- increase the net undeveloped acreage in the deep rights (2,500 metres and deeper) to 353,566 net acres.

The Company has no material amount of net undeveloped acreage that is expected to expire in 2017.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

At this time the Company has not completed an independent evaluation of its undeveloped acreage in Turkey. However, the Company completed in 2012 an independent assessment of its contingent resources on the TBNG JV lands in the Thrace Basin effective December 31, 2012 which identified significant discovered tight gas resource potential. The Company has not completed an updated independent assessment of its contingent resources as of December 31, 2016, pending further results from expected drilling on the TBNG JV lands and Banarli Licences in 2017.

Forward Contracts

Currently there are no material forward contracts or commitments.

Abandonment and Reclamation Costs

All wells assigned reserves are included in the D&M Reserves Report and are assigned abandonment and reclamation costs.

Abandonment and reclamation costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment and reclamation requirements. The Company has 97.42 net wells as of December 31, 2016 for which abandonment and reclamation costs are expected to be incurred.

In the D&M Reserves Report the total well abandonment cost in respect of proved reserves using forecast costs are US$4.3 million (undiscounted). All of this amount was deducted as abandonment and reclamation costs in estimating the Company's future net revenue as disclosed above.

In the D&M Reserves Report well abandonment and reclamation costs for all wells with reserves have been included at the property level. Additional abandonment and reclamation costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

Tax Horizon

The Company was not required to pay any cash income taxes in Turkey for the period ended December 31, 2016. Based on current estimates of the Company's future taxable income and expected future capital expenditures, management believes that the Company will not be required to pay cash income taxes in Turkey in 2017.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties in Turkey for the year ended December 31, 2016.

	Property Acquisition (Disposition) Costs(14) (M$)		**Exploration Costs(14) (M$)**	**Development Costs(14) (M$)**
	Proved Properties	**Unproved Properties**		
TBNG	-	-	-	58
Banarli			9,451	-
Other	-	-	-	-
Total Turkey	0	0	9,451	58

Exploration and Development Activities

The following table sets forth the number of wells the Company drilled for the year ended December 31, 2016 in Turkey (the Company did not drill any service wells or stratigraphic test wells):

	Exploratory Wells		Development Wells	
	Gross(1)(2)(3)	Net(1)(2)(3)	Gross(1)(2)(3)	Net(1)(2)(3)
Oil Wells	0	0.00	0	0.00
Gas Wells	0	0.00	1	1.00
Standing & Other Wells	0	0.00	0	0.00
Dry Holes	0	0.00	0	0.00
Total Wells	0	0.00	1	1.00

Notes:

(1) "**Gross Wells**" are the total number of wells in which the Company has an interest.

(2) "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

(3) Spud date is the criteria the Company uses to categorize drilled wells by year.

Production Estimates

The following table sets forth the volume of working interest daily production, before royalties, estimated for 2017 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of gross proved and probable reserves in Turkey:

	Light and Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Proved Developed Producing(2)(6)				
TBNG	3	0	1,685	0
Banarli	2	0	954	0
Total Proved Developed Producing	5	0	2,639	0
Proved Developed Non-Producing(2)(7)				
TBNG	0	0	828	0
Banarli	0	0	0	0
Total Proved Developed Non-Producing	0	0	828	0
Proved Undeveloped(2)(8)				
TBNG	0	0	183	0
Banarli	0	0	0	0
Total Proved Undeveloped	0	0	183	0
Total Proved(2)				
TBNG	3	0	2,696	0
Banarli	2	0	954	0
Total Proved	5	0	3,650	0
Total Probable(3)				
TBNG	0	0	328	0
Banarli	1	0	1,008	0
Total Probable	1	0	1,336	0
Total Proved Plus Probable(2)(3)				
TBNG	3	0	3,025	0
Banarli	3	0	1,962	0
Total Proved Plus Probable	6	0	4,986	0

Note:

See Notes that follow the table titled "R*econciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year for properties in Turkey:

	Three Months Ended March 31, 2016	**Three Months Ended June 30, 2016**	**Three Months Ended September 30, 2016**	**Three Months Ended December 31, 2016**
Average Daily Production				
Light and Medium Crude Oil (bbl/d)	9	7	10	12
Conventional Natural Gas (Mcf/d)	4,697	5,560	4,020	4,699
boes (boe/d)	792	933	680	795
Average Prices Received				
Light and Medium Crude Oil ($/bbl)[14]	39.75	54.41	56.24	63.67
Conventional Natural Gas ($/Mcf)[14]	10.05	9.44	9.35	7.96
boes ($/boe)[14]	60.09	56.62	56.10	47.97
Royalties				
Light and Medium Crude Oil ($/bbl)[14]	7.25	16.02	7.04	2.85
Conventional Natural Gas ($/Mcf)[14]	1.34	1.22	1.21	1.02
boes ($/boe)[14]	8.04	7.37	7.24	6.07
Production Costs				
Light and Medium Crude Oil ($/bbl)[14]	7.56	6.81	4.25	3.96
Conventional Natural Gas ($/Mcf)[14]	1.03	1.04	1.71	1.42
boes ($/boe)[14]	6.20	6.23	10.17	8.47
Netback Received				
Light and Medium Crude Oil ($/bbl)[14]	24.94	31.58	44.95	56.86
Conventional Natural Gas ($/Mcf)[14]	7.68	7.18	6.43	5.52
boes ($/boe)[14]	45.85	43.02	38.69	33.43

Note:

See Notes that follow the table titled "R*econciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

The following table sets forth certain information in respect of production that is included in the preceding table and is attributable to TBNG JV lands, the Company's major property:

	Three Months Ended March 31, 2016	**Three Months Ended June 30, 2016**	**Three Months Ended September 30, 2016**	**Three Months Ended December 31, 2016**
Average Daily Production				
Light and Medium Crude Oil (bbl/d)	6	3	4	7
Conventional Natural Gas (Mcf/d)	3,909	3,149	2,348	2,427
boes (boe/d)	658	528	395	412

APPENDIX A-2 – FORM 51-101F2 – REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

CANADIAN NATIONAL INSTRUMENT 51-101 FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Valeura Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2016. The reserves data are estimates of the proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) in thousands of United States dollars (M U.S.$) attributed to proved-plus-probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Reserves Committee of the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation	Location of Reserves	Net Present Value of Future Net Revenue (before Income Taxes, Discounted at 10 Percent)			
			Audited (M U.S.$)	Evaluated (M U.S.$)	Reviewed (M U.S.$)	Total (M U.S.$)
DeGolyer and MacNaughton	Report as of December 31, 2016 on Reserves and Revenue owned by Valeura Energy Inc. for Certain Properties in Turkey with a preparation date of March 14, 2017	Turkey	Not Applicable	45,715	Not Applicable	45,715

6. In our opinion, the reserves data and revenue associated with the proved-plus-probable reserves evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the preparation date.

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

DeGolyer and MacNaughton, Dallas, Texas USA, dated March 14, 2017.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton

APPENDIX A-3 – REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION – FORM 51-101F3

**REPORT OF
MANAGEMENT AND DIRECTORS ON RESERVES DATA
AND OTHER OIL AND GAS INFORMATION**

Report of Management and Directors on Reserve Data and Other Information (51-101F3)

Management of Valeura Energy Inc., (the "**Company**"), are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016 estimated using forecast prices and costs.

DeGolyer and MacNaughton, an independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

March 14, 2017

(signed) "*James D. McFarland*"
James D. McFarland
President and Chief Executive Officer

(signed) "*Donald W. Shepherd*"
Donald W. Shepherd
Vice President, Engineering

(signed) "*Ronald Royal*"
Ronald Royal
Director and Chairman of Reserves Committee

(signed) "*Timothy Marchant*"
Timothy Marchant
Director and Member of Reserves Committee

APPENDIX B – TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

APPENDIX B

TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

I. PURPOSE

The primary function of the Audit Committee (the "**Committee**") is to assist the Board in fulfilling its oversight responsibilities by reviewing:

A. the financial information that will be provided to the shareholders and others;

B. the systems of internal controls, management and the Board of Directors have established; and

C. all audit processes.

Primary responsibility for the financial reporting, information systems, risk management and internal controls of Corporation is vested in management and is overseen by the Board.

II. COMPOSITION AND OPERATIONS

A. The Committee shall be composed of not fewer than three directors and not more than five directors, all of whom are independent[1] directors of the Corporation.

B. All Committee members shall be "financially literate"[2] and at least one member shall have "accounting or related financial expertise". The Committee may include a member who is not financially literate, provided he or she attains this status within a reasonable period of time following his or her appointment and providing the Board has determined that including such member will not materially adversely affect the ability of the Committee to act independently.

C. The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in Tab 7 of the Board Manual.

D. The Corporation's auditors shall be advised of the names of the committee members and will receive notice of and be invited to attend meetings of the Audit Committee, and to be heard at those meetings on matters relating to the Auditor's duties.

E. The Committee has the authority to communicate with the external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or shareholders.

F. The Committee shall meet at least four times each year.

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[1] Independence requirements are described in the Appendix to Tab 5, Board Operating Guidelines.

[2] The Board has adopted the NI 52-110 definition of "financial literacy", which is an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

III. Duties and Responsibilities

Subject to the powers and duties of the Board, the Committee will perform the following duties:

A. *Financial Statements and Other Financial Information*

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes:

i) review and recommend approval of the Corporation's annual financial statements and MD&A and report to the Board of Directors before the statements are approved by the Board of Directors;

ii) review and approve for release the Corporation's quarterly financial statements and press release;

iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the public disclosure referred to in items (i) and (ii) above, and periodically assess the adequacy of those procedures; and

iv) review the Annual Information Form and any Prospectus/Private Placement Memorandums.

Review and discuss:

v) the appropriateness of accounting policies and financial reporting practices used by the Corporation;

vi) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Corporation;

vii) any new or pending developments in accounting and reporting standards that may affect the Corporation;

viii) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements; and

ix) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate.

B. *Risk Management, Internal Control and Information Systems*

The Audit Committee will review and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes:

i) review the Corporation's risk management controls and policies;

ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management, the internal auditor and external auditor; and

iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies.

C. External Audit

The External Auditor is required to report directly to the Committee, which will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

i) review and recommend to the Board, for shareholder approval, engagement and compensation of the external auditor;

ii) review and approve the annual external audit plan, including but not limited to the following:

- a) engagement letter;
- b) objectives and scope of the external audit work;
- c) procedures for quarterly review of financial statements;
- d) materiality limit;
- e) areas of audit risk;
- f) staffing;
- g) timetable; and
- h) approve fees;

iii) meet with the external auditor to discuss the Corporation's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;

iv) maintain oversight of the External Auditor's work and advise the Board, including but not limited to:

- a) the resolution of any disagreements between management and the External Auditor regarding financial reporting;
- b) any significant accounting or financial reporting issue;
- c) the auditors' evaluation of the Corporation's system of internal controls, procedures and documentation;
- d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;
- e) any other matters the external auditor brings to the Committee's attention; and
- f) assess the performance and consider the annual appointment or re-appointment of external auditors for recommendation to the Board ensuring that such auditors are participants in good standing pursuant to applicable regulatory laws;

v) review the auditor's report on all material subsidiaries;

vi) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation:

a) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation;

b) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors; and

c) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;

vii) review and pre-approve any non-audit services to be provided by the external auditor's firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit; and

viii) meet periodically, and at least annually, with the external auditor without management present.

D. Compliance

The Committee shall:

i) ensure that the External Auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;

ii) disclose any specific policies or procedures the Corporation has adopted for pre-approving non-audit services by the External Auditor including affirmation that they meet regulatory requirements;

iii) assist the Governance and Compensation Committee with preparing the Corporation's governance disclosure by ensuring it has current and accurate information on:

a) the independence of each Committee member relative to regulatory requirements for audit committees;

b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and

c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member;

iv) disclose if the Corporation has relied upon any exemptions to the requirements for Audit Committees under regulatory requirements.

E. Other

The Committee shall:

i) establish and periodically review implementation of procedures for:

a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

ii) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former External Auditor;

iii) review insurance coverage of significant business risks and uncertainties;

iv) review material litigation and its impact on financial reporting;

v) review policies and procedures for the review and approval of officers' expenses and perquisites;

vi) review policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Corporation;

vii) review with external auditors any corporate transactions in which directors or officers of the Corporation have a personal interest;

viii) review the terms of reference for the Committee annually and make recommendations to the Board as required;

ix) review list of gifts and entertainment expenses and other matters contemplated under the Anti-Corruption Policy; and

x) review the adequacy of the Anti-Corruption Policy and report on its implementation and matters arising thereunder to the Board.

IV. ACCOUNTABILITY

A. The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial matters relative to the Corporation.

B. The Committee shall report its discussions to the Board by maintaining minutes of its meetings and providing an oral report at the next Board meeting.