valeura energy inc.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three months and years ended December 31, 2018 and 2017

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Valeura Energy Inc. ("Valeura" or the "Company") is dated as of March 13, 2019 and should be read in conjunction with Valeura's audited consolidated financial statements and related notes for the years ended December 31, 2018 and 2017. Additional information relating to Valeura is available under Valeura's profile on www.sedar.com, including Valeura's Annual Information Form for the year ended December 31, 2018 ("2018 AIF"). The reporting currency is the Canadian Dollar ("CAD") (see the sections titled "Foreign Exchange" and "Currency Translation Adjustment" for discussion on Valeura's functional currencies).

Basis of Presentation

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") as at and for the years ended December 31, 2018 and 2017, and have been prepared in accordance with the accounting policies and methods of computation as set forth in note 3 of the consolidated financial statements.

The discussion and analysis of oil and natural gas production is presented on a working-interest, before royalty basis. For the purpose of calculating unit of production information, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe as a unit of measure may be misleading, particularly if used in isolation.

The Company makes estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the revenues and expenses during the reporting period. Management reviews these estimates, including those related to accruals, reserves, environmental and decommissioning obligations and income taxes at each financial reporting period. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Readers should be aware that historical results are not necessarily indicative of future performance.

Non-GAAP Measures

This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "operating netback", "adjusted funds flow" and "net capital" are non-GAAP measures and do not have standardised meanings prescribed by IFRS and are therefore unlikely to be comparable to similar measures used by other issuers. For further information, refer to the individual sections.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Highlights and Selected Financial Information

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Financial				
Petroleum and natural gas sales	**$ 3,150**	$ 3,824	**$ 11,969**	$ 14,646
Net loss	**(634)**	(946)	**(7,120)**	(8,384)
Per share, basic and diluted	**(0.01)**	(0.01)	**(0.09)**	(0.12)
Adjusted funds flow (used) [1]	**3,079**	(446)	**3,655**	(1,205)
Per share, basic and diluted	**$ 0.04**	$ (0.01)	**$ 0.04**	$ (0.02)
Production volumes				
Natural gas (Mcf/d)	**3,689**	6,176	**4,257**	5,662
Crude oil (bbl/d)	**8**	9	**8**	8
Total (boe/d)	**623**	1,038	**717**	952
Sales prices				
Natural gas (per Mcf)	**$ 9.06**	$ 6.61	**$ 7.54**	$ 6.98
Crude oil (per bbl)	**104.41**	82.78	**91.85**	71.84
Total (per boe)	**55.00**	40.03	**45.72**	42.16
Exploration and development capital	**$ 3,282**	$ 1,856	**$ 8,023**	$ 12,791
Acquisitions	**-**	-	**-**	21,450
Dispositions	**-**	-	**-**	(26,288)
Working capital[2]			**59,520**	3,421
Cash			**$ 62,380**	$ 11,108
Weighted average shares outstanding Basic and diluted (thousands)[3]	**86,222**	73,148	**83,659**	70,944

Outstanding Share Data

	December 31, 2018
Common shares	86,232,988
Stock options	4,598,667
Fully Diluted	90,831,655

[1] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1 and reconciliation to operating cash flow on page 12.

[2] Working capital is current assets less current liabilities.

[3] The weighted average number of common shares outstanding is not increased for outstanding stock options when the effect is anti-dilutive.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

The Company

Valeura is a Canada-based public company currently engaged in the exploration, development and production of oil and natural gas in the Thrace Basin of northwest Turkey. Valeura's shares are traded on the Toronto Stock Exchange ("TSX") under the trading symbol "VLE".

Valeura was established in 2010 to grow internationally through opportunistic acquisitions of producing assets with exploitation and exploration upside in selected countries in regions of interest, which included the Mediterranean Basin. The Company completed its first international transaction in Turkey during 2010 and since that time has executed a number of other transactions and won several new exploration licence awards in the country.

The asset and financing deals completed by the Company between Q4 2016 and Q1 2018 have transformed the Company by increasing the size of the asset base, giving Valeura operatorship of all key assets, and providing the financial capacity to explore and appraise the unconventional basin-centered gas accumulation ("BCGA") play. Additionally, the Company has secured Equinor Turkey B.V. ("Equinor") (name changed from Statoil in May 2018) as a large, well-respected partner which provides further technical and financial capacity to explore and appraise the deep, unconventional potential of the lands.

As at December 31, 2018, the Company held an interest in 20 exploration licences and production leases in the Thrace Basin of Turkey comprising approximately 0.46 million gross acres (0.37 million net acres of shallow rights and 0.26 million net acres of deep rights) as follows:

		Leases & Licenses	Gross Area (Acres)	Valeura Shallow Rights		Valeura Deep Rights	
				WI	Net Acres	WI	Net Acres
South Thrace Production Leases	Operated	11	170,735	81.5%	139,149	81.5%	139,149
West Thrace Production Leases	Operated	3	13,578	81.5%	11,066	31.5%	4,277
Erdine Production Leases	Non-Operated	3	49,883	35.0%	17,459	35.0%	17,459
Banarli Exploration Licenses[(1)]	Operated	2	133,840	100.0%	133,840	50.0%	66,920
West Thrace Exploration Licenses	Operated	1	88,434	81.50%	72,074	31.5%	27,857
Total			**456,470**		**373,588**		**255,662**

(1) To earn their 50% deep rights under the Banarli Farm-In Agreement, Equinor must still fund the fracking and testing of the Inanli-1 well. If this work program is not completed, Valeura reverts to 100% ownership.

The Company's primary producing assets are located in the South Thrace Lands and the West Thrace Lands, in each case, being the lands comprising the leases and licences described above (together the "TBNG JV Lands").

In the South Thrace Lands, the Company holds 11 production leases encompassing 170,735 gross acres. Valeura is the operator of the South Thrace Lands and holds an 81.5% working interest in the shallow rights and deep rights. The South Thrace Lands are jointly held by Valeura's wholly-owned subsidiaries, Thrace Basin Natural Gas Inc. ("**TBNG**") (41.5%) and Corporate Resources BV ("**CRBV**") (40%), and Pinnacle Turkey, Inc. ("**PTI**") holds the other 18.5% working interest. There is no work programme obligation to the government.

In the West Thrace Lands, the Company holds three production leases and one exploration licence encompassing 102,012 gross acres. The Company's 31.5% working interest in deep rights is held by TBNG, and the Company's 81.5% working interest in shallow rights is jointly held by TBNG (as to 41.5%) and CRBV (as to 40%). Equinor (as to 50%) and PTI (as to 18.5%) hold the remaining working interests in the deep rights, and PTI holds the remaining 18.5% working interest in the shallow rights. Valeura is the operator of the West Thrace Lands which are subject to joint operating agreements. The West Thrace Exploration Licence has a two well commitment to fulfill the work programme obligation which must be completed by June 26, 2020.

The Company holds two exploration licences in the Banarli Lands, being the lands comprising the licences described above, encompassing 133,840 gross acres. The Company holds a 100% working interest in the shallow rights and 50% working interest in the deep rights through CRBV. Equinor holds the other 50% working interest in the deep rights. Rights are subject to joint operating agreements and the Banarli fam-in and Valeura is currently the operator. The seismic and drilling work programme obligation to the government has been completed, except for geological and geophysical studies.

Equinor has a 50% working interest in the deep rights under the Banarli farm-in which requires Equinor to fully fund: (1) the drilling and testing of the Yamalik-1 well; (2) the acquisition and processing of the Karaca 3D seismic programme; and (3) the drilling and testing of Inanli-1 well. It is expected that Equinor will fulfill these obligations in 2019 once the testing of Inanli-1 is complete. If this work is not fully completed, 100% ownership of deep rights reverts to Valeura.

The boundary between the deep and shallow rights is determined by either a pressure gradient of 0.6 psi/ft (1.39 SG) or 2,500 metres depth, whichever is shallower. Valeura remains operator of the deep exploration programme on both the Banarli Licences and West Thrace Lands during Equinor's earning phase in Banarli. Equinor will have the option to request operatorship of the deep rights on both the Banarli and West Thrace Lands once they have fully earned. Additionally, under the Banarli farm-in agreement Equinor has no pre-emptive right related to Valeura's interests and there are some controls for Valeura's benefit related to the pace of appraisal drilling allowed prior to approval of a pilot project for development.

The Company's wholly-owned subsidiary, Valeura Energy Netherlands BV ("**VENBV**") holds a 35% working interest in three production leases in Edirne encompassing 49,883 gross acres. Otto Energy Limited (a subsidiary of TransAtlantic Petroleum) operates and holds the remaining 65% working interest. These leases currently do not have active operations or production.

The Company is focussed on growing its established business in Turkey, particularly its natural gas operations in the Thrace Basin which yields very high natural gas prices relative to North America. As a result of the success of the Yamalik-1 gas-condensate discovery, the primary focus of Valeura's business has transitioned to the delineation and commercial demonstration of the multi-TCF BCGA play. However, the Company still continues to optimise its established conventional shallow gas assets in the Thrace Basin.

Operations

Production Operations

The Company generates cash flow from sales of petroleum and natural gas production from its assets in the Thrace Basin of Turkey. The gas, which is composed primarily of methane, is gathered, dehydrated and compressed in Company-operated facilities and distributed on a Company-operated sales line network directly to 55 light industry customers. Valeura is the operator of all of its production operations.

The Company drilled one shallow (conventional) gas well in Q2 2018 in one of the West Thrace production leases. The Karanfiltepe-7 well was an obligation well that targeted a conventional fault-bounded trap. The well was a discovery which was immediately tied in to the infrastructure for production. In 2018, the Company completed a number of workovers of existing production wells and two re-entry high-pressure stimulations on existing wells. The Company performed some abandonment and reclamation activities on a number of older well sites which are no longer producing.

The Company is also continuing with its plan of selective low-cost workovers throughout the conventional play, to slow the natural decline from the existing fields.

BCGA Play

Valeura identified the potential for an unconventional BCGA play very early in its entry into the Thrace Basin. Based on the BCGA thesis, the Company acquired the Banarli Exploration Licences in 2013 and in 2015 and in the 2012 to 2015 period drilling the Kazanci-5, Hayrabolu-10 and Yayli-1 wells into deeper, overpressured formations which provided more evidence supporting the BCGA play concept.

After the Banarli Farm-in to the deep rights, the Company completed approximately 500 square kilometres of 3D seismic (Karaca) and drilled the Yamalik-1 exploration well. The Yamalik-1 well was drilled as the first well testing the BCGA thesis under the Banarli Farm-in. The well encountered highly overpressured gas saturated Teslimkoy and Kesan Formations from approximately 2,900 metres down to the total depth of 4,196 metres. The overpressure at the total depth was greater than 0.8 psi/ft based on testing results. The average net sand in the objective section was approximately 44%.

In the fourth quarter of 2017, Valeura completed four production tests in the Kesan formation in Yamalik-1 where each test was preceded by two slick-water high-pressure stimulations. The testing successfully demonstrated that gas and condensate would flow to surface post- high-pressure stimulation and a 24-hour aggregate production test rate of 2.9 million cubic fee per day ("MMcf/d") was achieved. The gas flowed with a significant amount of condensate (with a test data range of 20 to 70 barrels per MMcf). The ability to flow high-pressure gas from an area outside of a structural closure supported the interpretation of an unconventional BCGA play in the area of the well.

Activities in 2018 focused on the planning and commencement of an appraisal programme for the BCGA play to determine whether the overpressured gas is pervasive across the basin and to demonstrate that the gas could be flowed commercially. The notional programme agreed with Equinor was to drill three new appraisal wells, which would be high-pressure stimulated and tested if successful, and to further production test one or two historic wells.

In September 2018, Valeura recompleted the Yamalik-1 well following the tie-in of the well to the gathering system to allow for a production testing on a comingled basis. At the end of 24 hours of continuous production, the flow rate was 2.53 MMcf/d through a 20/64" choke with a wellhead pressure of 2,535 psi. After a period of intermittent flow of gas, condensate and water, a gas lift compressor was installed to assist in the ongoing flow back of stimulation fluids phase of initial production. Pressures and flow rates stabilised after the introduction of gas lift, and the well has continued to flow intermittently with a mixture of gas, condensate and water. The Company is continuing to evaluate the well to better understand the flow potential of the different zones in the well.

The first appraisal well, Inanli-1, was spudded in October 2018. The well was approximately 6 km from Yamalik-1 and the key objectives were to prove whether the over-pressured, gas-bearing reservoir discovered in the Yamalik-1 exploration well is laterally continuous and is indicative of a BCGA, to test for effective reservoir and over-pressured gas at deeper depths than Yamalik-1, and to test for the presence of enhanced natural fracturing in the reservoir. Drilling operations carried into January 2019 when the well reached total depth at 4,885 metres. Based on drilling and wireline logging data, the well is interpreted to have intersected over-pressured tight gas below 3,270 metres down to the total depth. A programme to high-pressure stimulate the well and test select intervals is currently being finalised and is expected to occur through Q2 2019.

The second appraisal well Devepinar-1 on the West Thrace Lands is located 20 km west of Yamalik-1 and Inanli-1 and was spudded in late February 2019. It is currently drilling.

Political and Regulatory Environment

Turkey has gone through a period of political change and uncertainty from 2016 to 2018. However, with the successful passing of the referendum on constitutional change, and the successful election in mid-2018, the incumbent, President Erdogan remains in office.

Recent geopolitical events have resulted in a continued downward slide in the value of the TL, and at times these drops have been very sharp. This has also had the effect of sharply increasing inflation to more than 20% in 2018 after well over a decade of strong growth and relatively stable inflation. In 2018, the resulting negative sentiment to Turkey has at times resulted in a decrease in the value of Valeura shares.

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 operations are in the Thrace Basin of northwest Turkey, more than 1,000 kilometres from the Syrian border, where security concerns are heightened.

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. The ability to make reliable estimates is further complicated when the political, economic and security situation is uncertain. Management has based its estimates with respect to the Company's operations on information available up to the date of this MD&A.

Outlook

Valeura is fully focused on appraising and de-risking its BCGA in the Thrace Basin. The objective of the Company's work programme for 2019 is to demonstrate that over-pressured gas is pervasive across Valeura's Thrace Basin lands and to show that commercial flow rates can be achieved. The key activities to support this objective include ongoing data-capture from the Yamalik-1 exploration well, and the Company's continuing appraisal drilling and testing programme.

Valeura is continuing to gather data from the Yamalik-1 exploration well, which was drilled and flow-tested in 2017, and subsequently recompleted and tied into the Company's production infrastructure in 2018. In 2019, the Company intends to re-enter the well to conduct production logging testing as a way to understand zone-by-zone fluid composition, thereby refining target intervals for future drilling and completion operations.

The Company concluded the drilling of the first of a three-well appraisal drilling campaign, Inanli-1, to a total depth of 4,885 metres in January 2019. Valeura announced positive results that the Inanli-1 well had encountered a 1,615 metre gross column of high net-to-gross, gas-bearing sandstone, and identified at least four zones interpreted to contain greater natural fracturing than previously observed. The well has been cased and left in a state ready for production testing. Fracking and testing operations are expected to commence in early Q2 2019 and could extend throughout the quarter. The Company is constructing a pipeline to tie in the well to its infrastructure in anticipation of a long-term production test.

Valeura began drilling the Devepinar-1 appraisal well in February 2019. The well is a substantial step-out from prior BCGA wells, approximately 20km from Yamalik-1, and accordingly, will test the lateral extent of the BCGA play to the western side of the basin. Given success, the Company intends to complete, frack, and production test the well. Costs for Devepinar-1 are being shared proportionately by the working interest share of each partner, with Valeura's share being 31.5%.

A third appraisal well is envisaged for 2019, and Valeura and its partners will select a location based on data gathered through drilling and testing Yamalik-1, Inanli-1, and Devepinar-1. Seven locations have been approved by the government as potential sites for the well.

Valeura remains very well positioned to finance its ongoing BCGA appraisal and all corporate activities through to 2020. The Company's working capital position is more than adequate to fund its working interest share of the two appraisal wells post Inanli-1 and all of the expected fracking and testing. In all its activities, the Company remains committed to continuing its safe and environmentally responsible operations and ensuring that operational and administrative functions are conducted in the most cost-efficient way.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Results of Operations

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Petroleum and natural gas sales	**$ 3,150**	$ 3,824	**$ 11,969**	$ 14,646
Royalties	**(432)**	(515)	**(1,611)**	(1,971)
Production costs	**(858)**	(1,174)	**(3,606)**	(4,423)
Operating netback[4]	**1,860**	2,135	**6,752**	8,252
Other income	**813**	314	**2,245**	1,363
General and administrative expenses	**(451)**	(701)	**(3,750)**	(4,606)
Transaction costs	**-**	-	**(287)**	(1,160)
Realised foreign exchange gain (loss)	**665**	(569)	**(468)**	(2,683)
Current tax recovery (expense)	**192**	(1,625)	**(837)**	(2,371)
Adjusted funds flow (used)[5]	**3,079**	(446)	**3,655**	(1,205)
Non-cash expenses				
Share-based compensation	**(543)**	(140)	**(1,514)**	(470)
Accretion on decommissioning liabilities	**(1,420)**	(487)	**(2,890)**	(1,779)
Unrealised foreign exchange gain	**1,147**	254	**1,016**	12
Depletion and depreciation	**(1,933)**	(2,510)	**(7,306)**	(9,025)
Exploration and evaluation expense	**-**	(43)	**-**	(707)
Deferred tax recovery (expense)	**(964)**	2,444	**(81)**	4,790
Net loss	**$ (634)**	$ (928)	**$ (7,120)**	$ (8,384)

Sales Volumes

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Natural gas (Mcf/d)	**3,689**	6,176	**4,257**	5,662
Crude oil (bbl/d)	**8**	9	**8**	8
Total (boe/d)	**623**	1,038	**717**	952

Sales volumes for Q4 2018 and the year ended December 31, 2018 were 623 boe/d and 717 boe/d, respectively, compared to 1,038 boe/d and 952 boe/d for the same periods in 2017. The decrease in Q4 2018 was due to natural declines causing lower gross production on both the TBNG JV Lands and Banarli Licenses. The gas and crude oil sales volumes for Q4 2018 do not include production from the Yamalik-1 well as the sales revenue has been capitalised as part of the completion and testing capital expenditure. Testing operations continue at Yamalik-1.

[4] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1 and reconciliation on page 9.

[5] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1 and reconciliation on page 12.

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Pricing Information

	Three months ended		Years ended	
Average reference prices	**December 31, 2018**	December 31, 2017	**December 31, 2018**	December 31, 2017
Natural gas – BOTAS (per Mcf)[6]	**TL 38.08**	TL 19.84	**TL 27.80**	TL 19.84
Natural gas – BOTAS (per Mcf)	**$ 9.18**	$ 6.65	**$ 7.61**	$ 7.07
Average exchange rate (TL/CAD)	**4.148**	2.984	**3.651**	2.805

	Three months ended		Years ended	
Average realised prices	**December 31, 2018**	December 31, 2017	**December 31, 2018**	December 31, 2017
Natural gas (per Mcf)	**$ 9.06**	$ 6.61	**$ 7.54**	$ 6.98
Crude oil (per bbl)	**$ 104.41**	$ 82.78	**$ 91.85**	$ 71.84

Natural gas sales from the TBNG JV Lands are under direct sales contracts to industrial buyers and power generation companies in the area and each contract is at a negotiated discount or premium to the BOTAS Reference Price, described below. Natural gas from Banarli is being sold to the TBNG JV, net of a transportation and marketing fee. Valeura receives the majority of the benefits from this fee arrangement and the associated proceeds by virtue of its current 81.5% working interest in the TBNG JV facilities.

In Turkey the price of natural gas is set by BOTAS, the state-owned enterprise that owns most of the gas pipelines and controls most of the import contracts for natural gas into Turkey. The BOTAS Reference Price is denominated in TL. Historically, the BOTAS Reference Price has behaved in a similar manner to the regional price for natural gas when translated to US dollars ("USD"), though price changes have tended to lag the more market-driven natural gas prices in the region. In 2018, BOTAS introduced regular updates to the natural gas price and since mid-2018 the price has been adjusted, if required, on the first day of the month. Analysis suggests that these price adjustments are taking into account variations in the regional price of natural gas, and changes in the TL exchange rate. While indications are that the BOTAS pricing continues to move toward a more market-driven price for natural gas, there is no guarantee that the government will continue this policy in the future.

Effective January 1, 2018, April 1, 2018, August 1, 2018, September 1, 2018 and October 1, 2018 the BOTAS Reference Price was increased by 14%, 10%, 14%, 14% and 18.5% respectively. The Company's Q4 2018 average realised natural gas price in Turkey increased to $9.06 per Mcf from $6.61 per Mcf in Q4 2017 due to the price increases in 2018 offset by the devaluation of the TL against the CAD.

In 2018, the average realised natural gas price in Turkey of $7.54 per Mcf represents a 1.0% discount to the BOTAS benchmark price. The Company has reduced the discount on its natural gas sales contracts from prior year levels of 3% to 5% since taking control of the gas marketing activities for the Thrace Basin lands. In Q4 2018, the average realised price of $9.06 per Mcf represents a 1.0% discount to the BOTAS benchmark price.

[6] BOTAS owns and operates the national crude oil and natural gas pipeline grids in Turkey and purchases the majority of Turkey's natural gas imports. BOTAS regularly posts prices and its Level-2 Wholesale Tariff benchmark is shown herein as a reference price. See the 2018 AIF for further discussion.

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Petroleum and Natural Gas Sales Revenues

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Natural gas	**$ 3,075**	$ 3,754	**$ 11,708**	$ 14,431
Crude oil	**75**	70	**261**	215
Total revenues	**$ 3,150**	$ 3,824	**$ 11,969**	$ 14,646

The composition of petroleum and natural gas sales revenues for Q4 2018 and the year ended December 31, 2018 was approximately 98 percent natural gas and two percent crude oil. Revenues for Q4 2018 and the year ended December 31, 2018 decreased in comparison to the same periods in 2017 due primarily to lower production volumes, offset partially by higher prices.

Royalties

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Royalties	**$ 432**	$ 515	**$ 1,611**	$ 1,971
Percentage of revenue	**13.7%**	13.5%	**13.5%**	13.5%

Royalties for Q4 2018 and the year ended December 31, 2018 decreased in comparison to the same periods in 2017 as a result of lower petroleum and natural gas sales revenues. Revenues are subject to a 12.5% government royalty and an overriding royalty only on the TBNG JV Lands of one percent.

Production Costs

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Production costs	**$ 858**	$ 1,174	**$ 3,606**	$ 4,423
$ per boe	**14.98**	12.29	**13.77**	12.73

Production costs for Q4 2018 and the year ended December 31, 2018 decreased in comparison to the same periods in 2017 due to improved efficiencies in 2018 compared to higher costs in 2017 associated with integrating the Company's acquisition of TBNG (the "TBNG Acquisition"). The higher unit production costs are reflective of the level of fixed costs included in total operating costs and lower gross production from the TBNG JV Lands and Banarli Licenses.

Operating Netbacks (per boe)

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Petroleum and natural gas sales	**$ 55.00**	$ 40.03	**$ 45.72**	$ 42.16
Royalties	**(7.54)**	(5.39)	**(6.16)**	(5.67)
Production costs	**(14.98)**	(12.29)	**(13.77)**	(12.73)
Operating netback[7]	**$ 32.48**	$ 22.35	**$ 25.79**	$ 23.76

[7] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

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Operating netbacks in Q4 2018 and the year ended December 31, 2018 increased in comparison to the same periods in 2017 due primarily to higher realised prices offset by higher per unit production costs.

Operating netback is a non-GAAP measure and is equal to petroleum and natural gas sales less royalties, production expenses and transportation costs. The Company considers operating netback an important measure as it demonstrates its profitability level relative to current commodity prices.

General and Administrative Expenses

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
General and administrative expenses	**$ 1,736**	$ 1,506	**$ 7,828**	$ 6,893
Recoveries and capitalised general administrative expenses	**(1,285)**	(805)	**(4,078)**	(2,287)
Net general and administrative expenses	**$ 451**	$ 701	**$ 3,750**	$ 4,606

Total general and administrative expenses before recoveries for 2018 increased in comparison to the same periods in 2017 as a result of increased personnel related to the expansion of the business and operations.

Net general and administration costs to Valeura are significantly lower due to increased overhead recoveries primarily from the deep drilling and testing programme on the BCGA.

Foreign Exchange

Foreign exchange (realised and unrealised) for Q4 2018 and the year ended December 31, 2018 was a gain of $1.8 million and $0.5 million, respectively, compared to a loss of $0.3 million and $2.7 million for the same periods in 2017.

The functional currency for the Company's Turkish operations is the TL. Foreign exchange gains and losses are the result of translation of accounts denominated in currencies other than the functional currencies of Valeura and its subsidiaries, and settling transactions denominated in currencies other than the functional currency of the entity.

The Company's petroleum and natural gas sales are conducted in Turkey and are denominated in TL. As such, the Company is exposed to any fluctuations in the TL to CAD and USD exchange rates. A decrease in the value of the TL against the CAD or USD will result in a decrease in revenues, royalty expense and operating costs. Correspondingly, an increase in the value of the TL against the CAD and USD will result in an increase in revenues, royalty expense and operating costs. Changes in the value of the TL against the CAD and USD could also impact reserve values.

The recent negative volatility in the value of the TL may impair the ability of the Company to effectively manage foreign exchange exposure. Continued devaluation of the TL, without a corresponding increase in the natural gas reference price, will have a negative impact on adjusted funds flow and could affect the ability of the Company to fund its capital programme in the future. Historically, any devaluation in the TL has been followed by a legislated increase in the posted BOTAS Reference Price for natural gas.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Changes to the TL/CAD exchange rate would have had the following impact on revenues, royalties and production costs for the three months and year ended December 31, 2018:

+/- 1 percent change in realised TL/CAD exchange rate	Petroleum and natural gas revenues	Royalties	Production costs
Three months ended December 31, 2018	$ 35	$ 4	$ 9
Year ended December 31, 2018	$ 120	$ 16	$ 37

The Company's drilling and seismic operations and related contracts in Turkey are predominantly based in USD. Material changes in the value of the USD against the TL or CAD will impact the Company's capital costs.

Changes to the TL/USD exchange rate, which are impacted by the TL/CAD exchange rate upon conversion to the Company's CAD presentation currency, would have had the following impact on capital expenditures for the three months and year ended December 31, 2018:

+/- 1 percent change in realised TL/USD exchange rate, upon conversion to presentation currency	Capital expenditures
Three months ended December 31, 2018	$ 204
Year ended December 31, 2018	$ 320

Other Income

During Q4 2018 and the year ended December 31, 2018, the Company recorded other income of $0.8 million and $2.2 million, respectively, compared to $0.3 million and $1.4 million for the same periods in 2017. Other income is comprised of third party processing and marketing income and interest income related to cash on hand. The majority of the increase can be attributed to interest income as a result of higher average cash levels in 2018 in comparison to 2017. During Q4 2018 and the year ended December 31, 2018 the Company recorded third party processing and marketing income of $0.3 million and $0.9 million, respectively, and interest income of $0.5 million and $1.3 million, respectively.

Current Tax

Current tax for Q4 2018 and the year ended December 31, 2018 was a recovery of $0.2 million and an expense of $0.8 million, respectively, compared to an expense of $1.6 million and $2.4 million for the same periods in 2017.

In 2018, the Company elected to participate in a tax amnesty programme offered by the Government of Turkey, which allowed companies to pay an amount based on a pre-determined formula to close tax assessments for certain years between 2013 and 2017. In deciding to participate in the programme, the Company analysed the costs and risks involved in current tax positions, including those related to companies that were acquired during this time frame, versus the potential financial burden that would be incurred by not participating in the programme and then being unsuccessful in defending tax positions against multiple audits.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

The tax amnesty payment is included in current taxes along with current income taxes as follows:

	Three months ended December 31, 2018	Year ended December 31, 2018
Current income taxes (recovery)	$ (192)	$ 323
Tax amnesty payment	-	514
Current income taxes (recovery)	**$ (192)**	**$ 837**

Adjusted Funds Flow

Adjusted funds flow for Q4 2018 and the year ended December 31, 2018 was $3.1 million and $3.7 million, respectively, compared to an outflow of $0.4 million and an outflow of $1.2 million for the same periods in 2017. Adjusted funds flow in Q4 2018 increased due to higher realised prices and increased foreign exchange gains due to the strengthening of the TL. The increase in adjusted funds flow for 2018 was due to increased realised prices and absence of expenses related to the TBNG Acquisition and Banarli farm-in which negatively impacted 2017 results. The increase was partially offset by tax amnesty payments described above in the Current Tax section of this MD&A.

The following table reconciles Valeura's cash provided by operating activities to adjusted funds flow:

	Three months ended		**Years ended**	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Cash provided by (used in) operating activities	**$ 5,309**	$ 7,484	**$ (584)**	$ 3,854
Decommissioning costs incurred	**134**	256	**531**	270
Change in non-cash working capital	**(2,364)**	(8,186)	**3,708**	(5,329)
Adjusted funds flow (used) [8]	**$ 3,079**	$ (446)	**$ 3,655**	$ (1,205)

Adjusted funds flow is a non-GAAP measure and is based on cash provided by operating activities before decommissioning costs incurred and changes in non-cash working capital. The Company considers adjusted funds flow a key measure as it demonstrates the ability of the Company's continuing operations to generate the cash flow necessary to fund future growth through capital investments. Certain non-cash charges and decommissioning costs have been excluded from the calculation of adjusted funds flow, as management believes the timing of collection, payment and incurrence is variable and by excluding them from the calculation management is able to provide a more meaningful measure of the Company's cash flow from continuing basis.

Non-cash Expenses:

Share-based Compensation

Share-based compensation is a non-cash expense associated with the stock options issued to directors, officers, employees and certain other service providers of the Company.

Share-based compensation expense for Q4 2018 and the year ended December 31, 2018 was $0.5 million and $1.5 million, respectively, compared to $0.1 million and $0.5 million for the same periods in 2017. During 2018, the Company granted 1,077,500 options at a weighted average exercise price of $4.62 per option.

[8] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Accretion on Decommissioning Liabilities

Accretion on decommissioning obligations for Q4 2018 and the year ended December 31, 2018 was $1.4 million and $2.9 million, respectively, compared to $0.5 million and $1.8 million for the same periods in 2017. The increase is due to high levels of inflation in Turkey during 2018 and the devaluation of the TL against the USD during the year.

Depletion and Depreciation

Depletion and depreciation for Q4 2018 and the year ended December 31, 2018 was $1.9 million and $7.3 million, respectively, compared to $2.5 million and $9.0 million for the same periods in 2017. The decrease in depletion and depreciation compared to 2017 was primarily due to lower production volumes and the weakening of the TL. Depletion is calculated on a unit-of-production basis utilising proved plus probable reserves.

On a per unit basis, depletion and depreciation for Q4 2018 and the year ended December 31, 2018 was $33.73/boe and $27.92/boe, respectively, compared to $26.28/boe and $25.97/boe for the same periods in 2017.

Deferred Tax

Deferred tax for Q4 2018 and the year ended December 31, 2018 was an expense of $1.0 million and $0.1 million, respectively, compared to a recovery of $2.4 million and $4.8 million for the same periods in 2017. Deferred tax relates to changes in the temporary difference between the net book value and the tax basis of the assets and liabilities in the Company's Turkish operations.

Currency Translation Adjustments

Translation of all assets and liabilities from their respective functional currencies to the reporting currency are performed using the rates prevailing at the statement of financial position date. The differences arising upon translation from the functional currency to the reporting currency are recorded as currency translation adjustments in accumulated other comprehensive income or loss ("AOCI") and are held within AOCI until a disposal or partial disposal of a subsidiary. A disposal or partial disposal will then give rise to a realised foreign exchange gain or loss which is recorded in net earnings.

The currency translation adjustment for Q4 2018 and the year ended December 31, 2018 was a gain of $6.7 million and a loss of $10.4 million, respectively, compared to a loss of $2.3 million and $6.0 million for the same periods in 2017 reflecting the fluctuation of the TL compared to the CAD in the respective periods.

Capital Expenditures

The following summarises the Company's capital spending:

	Three months ended		Years ended	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Geological and geophysical	**$ 83**	$ 142	**$ 229**	$ 932
Drilling & completions	**3,071**	785	**6,859**	8,830
Workovers & recompletions	**79**	894	**534**	2,287
Equipping, facilities & other	**49**	35	**401**	742
Total exploration and development capital programme	**3,282**	1,856	**8,023**	12,791
Acquisitions	**-**	-	**-**	21,450
Dispositions	**-**	-	**-**	(26,288)
Total net capital[9]	**$ 3,282**	$ 1,856	**$ 8,023**	$ 7,953

[9] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Net capital is a non-GAAP measure and is equal to cash flow used in investing activities, excluding changes in non-cash working capital and restricted cash. The Company considers net capital expenditures to be a useful measure of cash flow used for capital reinvestment.

The Company's capital spending for 2018 was $8.0 million, including $6.9 million for drilling and completions, $0.5 million for workovers and recompletions, $0.4 million for equipping, facilities and other and $0.2 million for geological and geophysical.

During 2018, the Company's focus was on the deep drilling programme. Valeura successfully recompleted the Yamalik-1 well to allow for a long-term production test. The Company's share of costs relating to the final completion and long term test was $2.5 million for 2018. Procurement and planning for a three well appraisal drilling and testing programme, including purchase of long lead items for wells to be drilled in 2019 was carried out during 2018 at a cost of $2.4 million to Valeura. In October 2018, the Company spud the first appraisal well, Inanli-1, which was drilled to a total depth of 4,885 metres. The well has been cased and is ready for completion fracking and production testing. Completion operations are planned to commence around the end of Q1 2019. Equinor will fund the drilling, completion and testing of the Inanli-1 well. In November 2018, site preparation commenced for the Devepinar-1 well, which spudded February 19, 2019.

In 2018, on the TBNG JV Lands, the Company drilled one well, Karanfiltepe-7 (Valeura has a 81.5% working interest). Karanfiltepe-7 was drilled to a measured depth of 1,454 metres and is currently on production. This well was strategically important as it fulfilled a license commitment at a low cost of $0.8 million for 2018. Valeura also completed workovers on five gross wells on the TBNG JV Lands.

2019 Planned Capital Programme

Valeura's 2019 capital programme will be almost entirely focused on the drilling and testing of wells to delineate and demonstrate commerciality of the unconventional BCGA play discovered by Yamalik-1 in 2017. Funds are also allocated for the tie-in of these wells to allow for production and sales of any discovered gas.

The plan for capital expenditures for the 2019 BCGA programme is as follows:

Operation	Net VLE Cost (in dollars)	Anticipated Timing
Test and complete Inanli-1 (Banarli)	$0	Q1 2019 – Q2 2019
Drill and Test Devepinar-1 (West Thrace)	$13,500,000	Q1 2019 – Q3 2019
Drill and Test a third planned BCGA appraisal well (Banarli)	$19,700,000	Q3 2019 – Q4 2019
Workovers and Production Testing of BCGA Wells	$3,750,000	2019
Facilities Capital and Tie-in for 4 wells	$2,300,000	2019
G&G and studies	$900,000	2019
Total:	**$40,150,000**	

The table above primarily outlines the deep BCGA programme. In support of its conventional, shallow production, Valeura also plans to spend approximately $1.5 million for workovers, abandonment and restoration and other facilities maintenance projects on the TBNG JV lands. The total capital budget for 2019 is approximately $41.7 million

The Company maintains considerable flexibility in managing its capital budget for 2019. Valeura expects to maintain operatorship of the deep rights on the Banarli Lands and West Thrace Lands for most of 2019 and through the drilling, completion and testing of the three well appraisal programme and will tightly manage all capital requirements and commitments. In addition, the drilling and workover capital spending on the TBNG JV Lands is only focused on fulfilling drilling commitments and mitigating natural gas production declines.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Share Capital

Common shares	Number of Shares	Amount
Balance, December 31, 2017	73,148,321	$ 146,694
Offering	10,527,000	55,409
Stock options exercised	2,557,667	3,218
Balance, December 31, 2018	**86,232,988**	**$ 205,321**

As at December 31, 2018, Valeura had 86,232,988 common shares outstanding and 4,598,667 outstanding options, for a total diluted number of shares outstanding of 90,831,655, assuming exercise of all options. On March 1, 2018, the Company closed a bought deal financing issuing 10,527,000 common shares at a price of $5.70 per common share for net proceeds (after share issue costs) of approximately $55.7 million. The total number of diluted shares outstanding at March 13, 2019 is 92,406,655 assuming exercise of all outstanding stock options.

Liquidity, Financing and Capital Resources

	Three months ended		**Years ended**	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
Opening cash position	**$ 56,522**	$ 2,968	**$ 11,108**	$ 1,987
Inflow of funds				
Share issuance – net of share issuance costs	**-**	-	**55,408**	10,108
West Thrace deep rights sales	**-**	-	**-**	18,841
Equinor farm-in proceeds	**-**	-	**-**	7,447
Adjusted funds flow[10]	**3,079**	-	**3,655**	-
Restricted cash	**2,059**	223	**2,899**	-
Proceeds from stock option exercises	**96**	-	**1,912**	-
Foreign exchange on cash	**937**	262	**2,375**	531
Changes in non-cash working capital[11]	**3,103**	10,213	**-**	11,083
	9,274	10,698	**66,249**	48,010
Outflow of funds				
Capital expenditures[12]	**(3,282)**	(1,856)	**(8,023)**	(12,791)
Decommissioning costs incurred	**(134)**	(256)	**(531)**	(270)
TBNG Acquisition	**-**	-	**-**	(21,450)

[10] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

[11] Includes the following captions from the consolidated statements of cash flows: changes in non-cash working capital from operating activities and changes in non-cash working capital from investing activities.

[12] Includes the following captions from the consolidated statements of cash flows: exploration and evaluation expenditures and property and equipment expenditures.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Restricted cash	**-**	-	**-**	(3,173)
Changes in non-cash working capital[13]	**-**	-	**(6,423)**	-
Adjusted funds flow (used)	**-**	(446)	**-**	(1,205)
	(3,416)	(2,558)	**(14,977)**	(38,889)
Closing cash position	**$ 62,380**	$ 11,108	**$ 62,380**	$ 11,108

Capital Funding and Resources

As at December 31, 2018, Valeura's working capital[14] balance was $59.5 million (2017 - $3.4 million) including cash of $62.4 million. Valeura's 2018 opening cash position was $11.1 million. The increase in the working capital/cash position in 2018 was mainly due to the net proceeds of $55.4 million from the equity financing (net of share issuance costs) completed in Q1 2018 ("the 2018 Offering"). In 2018, the Company utilised this cash balance plus adjusted funds flow to fund an exploration and development capital programme of $8.0 million.

Financial Capacity

On March 1, 2018 the Company closed the 2018 Offering, issuing common shares for net proceeds of approximately $55.4 million, after share issue costs. Valeura intends to use the net proceeds from the 2018 Offering to fund its 2018 and 2019 capital programme (outlined above) and for general corporate purposes.

As at December 31, 2018 the Company's working capital[15] was $59.5 million.

Capital Management

The Company's objective when managing capital is to maintain a flexible capital structure which allows it to execute its growth strategy through expenditures on exploration and development activities while maintaining a strong financial position. The Company's capital structure includes working capital and shareholders' equity. Currently, total capital resources available include working capital and funds flow from operations.

The Company's capital expenditure includes expenditures in oil and gas activities which may or may not be successful. The Company makes adjustments to the capital structure in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. In order to maintain or adjust the capital structure, the Company may, from time to time, issue shares, adjust its capital spending or issue debt instruments. The Company is not currently subject to any externally imposed capital requirements while it maintains operatorship over all the lands in the Thrace Basin. An exception to this statement could occur in 2019, if Equinor completes its earning obligations under the Banarli Farm-in and thereby earns a 50 percent working interest in the deep rights at Banarli and subsequently exercises its option to take operatorship of the deep rights and propose a more significant drilling programme including a more extensive pilot project, for which the Company would have to contribute its 50 percent participating interest. Such a programme could result in a more significant capital commitment than currently forecast, and may necessitate the Company assessing alternatives including the availability of equity and debt capital to fund the programme.

The successful future operations of the Company are dependent on the ability of the Company to secure sufficient funds through operations, bank financing, equity offerings or other sources and there are no assurances that such

[13] Includes the following captions from the consolidated statements of cash flows: changes in non-cash working capital from operating activities and changes in non-cash working capital from investing activities.

[14] Working capital is current assets less current liabilities.

[15] Working capital is current assets less current liabilities.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

funding will be available when needed. Failure to obtain such funding on a timely basis could cause the Company to reduce capital spending and could lead to the loss of exploration licences due to failure to meet drilling deadlines.

Valeura has not utilised bank loans or debt capital to finance capital expenditures to date. In the future, if the Company establishes and borrows on a bank loan facility for capital expansion, the Company will monitor capital based on the ratio of net debt to annualised funds from operations. This ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant.

Credit Facilities

The Company has a general credit facility in the amount of US$0.3 million with a Turkish bank for the purpose of obtaining letters of credit required by the Turkish government. As at December 31, 2018, the Company has issued letters of credit totaling US$0.04 million (December 31, 2017 – US$0.04 million). The general credit facility is not secured by any of the Company's assets and interest rate terms have not been set as the purpose of this facility is for issuance of letters of credit only.

Effective June 22, 2018, the Company has available an Account Performance Security Guarantee ("APSG") from Export Development Canada ("EDC"). The APSG, which was issued to National Bank of Canada ("NBC") allows the Company to use the APSG as collateral for certain letters of credit issued by NBC. The facility is effective from May 16, 2018 to May 31, 2019 with a limit of US$2.5 million and can be renewed on an annual basis. The Company has issued US$2.5 million in letters of credit under the APSG facility at current exchange rates. This allowed the Company to release approximately US$2.0 million of restricted cash.

Selected Quarterly Information

	Three months ended			
	December 31, 2018	**September 30, 2018**	**June 30, 2018**	**March 31, 2018**
Total daily production (boe/d)	623	655	736	859
Average wellhead price ($/boe)	$ 55.00	$ 39.83	$ 44.06	$ 44.87
Petroleum and natural gas sales	3,150	2,401	2,949	3,469
Adjusted funds flow (used) [16]	3,079	(430)	461	545
Per share, basic and diluted	0.04	(0.01)	0.01	0.01
Net loss	(634)	(2,647)	(1,404)	(2,435)
Per share, basic and diluted	$ (0.01)	$ (0.03)	$ (0.02)	$ (0.03)
	Three months ended			
	December 31, 2017	**September 30, 2017**	**June 30, 2017**	**March 31, 2017**
Total daily production (boe/d)	1,038	1,024	934	807
Average wellhead price ($/boe)	$ 40.03	$ 42.14	$ 44.28	$ 42.49
Petroleum and natural gas sales	3,824	3,970	3,764	3,088
Adjusted funds flow (used) [17]	(446)	1,165	959	(2,883)
Per share, basic and diluted	(0.01)	0.02	0.01	(0.04)
Net loss	(946)	(4,911)	(526)	(2,001)
Per share, basic and diluted	$ (0.01)	$ (0.07)	$ (0.01)	$ (0.03)

[16] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

[17] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

(tabular amounts in thousands of Canadian Dollars, except share, per share or per unit amounts)

Significant factors that have impacted the Company's results during the above periods include:

- Revenue is directly impacted by the Company's ability to mitigate natural production declines with production additions from an on-going capital expenditure programme and acquisitions.
- Valeura has benefited from relatively high natural gas prices and netbacks in Turkey compared to North America, although the weakening of the TL since 2016 reduced wellhead price realisations throughout 2017 and the first nine months of 2018. The 2018 increases to the BOTAS Reference Price combined with the strengthening of the TL in Q4 2018 has resulted in higher wellhead price realisation.
- With its revenues in TL, capital expenditures primarily in USD and reporting currency in CAD, Valeura has a high level of foreign exchange and currency translation exposure.

Fourth Quarter Review

During Q4 2018, petroleum and natural gas sales were up 31% from Q3 2018 due to the BOTAS Reference Price increase and the strengthening of the TL during the quarter. Petroleum and natural gas sales were down 18 percent from Q4 2017 due to natural declines on both the TBNG JV and Banarli Licenses. The Company spent $3.3 million on exploration and development capital which was funded by adjusted funds flow and the existing cash position. Net loss of $0.6 million was recorded in Q4 2018, which reflects recognition of $1.9 million of depletion and depreciation, $0.5 million of share-based compensation, $1.4 million of accretion on decommissioning liabilities and $1.0 million deferred tax expense.

Selected Annual Information

			Years Ended
	December 31, 2018	December 31, 2017	December 31, 2016
Petroleum and natural gas sales	$ 11,969	$ 14,646	$ 16,155
Cash provided by operations	(584)	3,854	6,294
Adjusted funds flow [18]	3,655	(1,205)	6,048
Per share, basic and diluted	0.04	(0.02)	0.10
Net loss	(7,120)	(8,384)	(6,086)
Per share, basic and diluted ($/share)	(0.09)	(0.12)	(0.10)
Daily production (boe/d)	717	952	799
Sales price ($/boe)	45.72	42.16	55.22
Cash	62,380	11,108	1,987
Total assets	128,323	89,872	75,890
Total long term liabilities	17,717	21,676	13,017
Net working capital[19]	$ 59,520	$ 3,170	$ 3,786

Valeura's petroleum and natural gas sales, cash provided by operations, adjusted funds flow and net loss are all impacted by production levels and commodity pricing. Daily production in 2018 decreased 18 percent from 2017 due to natural declines on both the TBNG JV and Banarli Licenses. Natural gas prices were strong in Turkey over the three year period but have been negatively impacted by the devaluation of the TL to the CAD. Total assets in 2017 and 2018 increased as a result of the TBNG Acquisition and 2018 Offering but were negatively impacted by the devaluation of the TL against the CAD.

[18] Non-GAAP measure that does not have any standardised meaning under IFRS and therefore may not be comparable to similar measures presented by other entities – see note regarding non-GAAP measures on page 1.

[19] Working capital is current assets less current liabilities.

New Accounting Pronouncements and Critical Accounting Policies

Use of Estimates and Judgments

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. The reader is referred to Valeura's December 31, 2018 audited consolidated financial statements for a description of estimates and judgments.

Recent Accounting Standards and Interpretations

In January 2016, the IASB issued the complete IFRS 16 Leases ("IFRS 16") which replaces IAS 17, Leases. The effective date of IFRS 16 is for annual periods beginning on or after January 1, 2019 and early adoption is permitted. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The Company is in the final stages of analysing identified contracts, developing business and accounting processes, making applicable changes to the Company's internal controls and calculating the impact that the adoption of this standard will have on its financial statements. Valeura has elected to use the modified retrospective approach upon adoption and elected to apply the optional exemptions for short-term and low-value leases. The actual full impact of adoption will depend on the Company's incremental borrowing rate, lease liabilities, and practical expedients applied. However, the Company anticipates that the most significant impact of adopting IFRS 16 will be the recognition of the right-of-use ("ROU") assets and corresponding lease liabilities on its operating leases for office space and surface leases for facilities.

Upon adoption of IFRS 16, the Company will recognise ROU assets and lease liabilities for all leases identified except for optional exemptions taken. The lease liability will be measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate as at January 1, 2019. The ROU asset will be measured at the amount equal to the lease liability on January 1, 2019 with no impact on retained earnings.

Adoption of IFRS 16 will also result in an increase to depletion, depreciation and amortisation expense due to the recognition of the ROU assets, increase in interest and financing charges, and a decrease to general and administrative and operating expenses, as applicable. Cash flow from operating activities will increase as a result of the decrease in general and administrative and operating expenses, as applicable, partially offset by interest and financing charges. Cash flow from financing activities will decrease due to the addition of principal payments included in lease payments for former operating leases.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") for Valeura. DC&P, as defined in National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarised and reported within the time periods specified under Canadian securities law and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. The CEO and CFO of Valeura evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the officers concluded that Valeura's DC&P were effective as at December 31, 2018.

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company; (ii) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the Company are being made in accordance with authorisations of management and Directors of the Company; and (iii) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorised acquisition, use, or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

The CEO and CFO are responsible for establishing and maintaining ICFR for Valeura. They have, as at the financial year ended December 31, 2018, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Under the supervision of the CEO and CFO, Valeura conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2018 and concluded that as of December 31, 2018, ICFR was effective. The Company uses the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") – Integrated Framework ("2013 Framework"). Valeura has designed its internal controls over financial reporting based on the 2013 framework. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Off Balance Sheet Arrangements

The Company had no off balance sheet arrangements outstanding as at December 31, 2018 other than those previously disclosed in this MD&A.

Financial Instruments

Financial instruments of the Company include cash, accounts receivable, accounts payable and accrued liabilities. The carrying values of the financial instruments approximate their fair values due to their relatively short periods to maturity.

Business Risks and Uncertainties

The reader is referred to the 2018 AIF for a more complete description of business risks and uncertainties.

Political Risks

As discussed previously, the political environment in Turkey has been impacted by recent events. The Company will continue to monitor conditions including the safety of personnel and operations, the security situation generally, impact on the TL and banking facilities, the functioning of the Republic of Turkey's General Directorate of Petroleum Affairs ("GDPA"), impact on our joint venture partners and any changes in offtakes by our natural gas customers.

Variations in Foreign Exchange Rates and Interest Rates

The Company's functional currency in its subsidiary operations in Turkey is the TL. The revenue stream in Turkey is based on Turkish Lira revenue for natural gas sales and USD based revenue for crude oil translated into Turkish Lira. Decreases in the value of the TL could therefore result in decreases in revenue. The Company's drilling operations in Turkey and related contracts are based primarily in USD. Operating costs in Turkey are based primarily in TL. Material increases in the value of the USD compared to the CAD will negatively impact the Company's costs of seismic and drilling and completions activity. Increases in the value of the TL could result in increases in operating costs. Future CAD/USD and USD/TL exchange rates could also impact the future value of the Company's reserves as determined by independent evaluators.

The recent volatility and weakness in the value of the TL may impair the ability of the Company to manage this exposure. Continued devaluation of the TL without a corresponding increase in the natural gas reference price will have a negative impact on adjusted funds flow and could affect the ability of the Company to fund its capital programme in the future.

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. The Company is in the process of specifically assessing its exposure to the TL and any possibilities that may exist to mitigate such exposure.

Foreign Operations

The Company pursues operations outside of Canada. As such, the Company's operations will be subject to a number of 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, working conditions, rates of exchange, exchange control, exploration licensing, petroleum and export licensing and export duties as well as government control over domestic oil and gas pricing. Problems may also arise due to the quality or failure of locally obtained equipment or technical support, which could result in failure to achieve expected target dates for exploration operations or result in a requirement for greater expenditure.

The Company will operate in such a manner as to minimise and mitigate its exposure to these risks. However, there can be no assurance that the Company will be successful in protecting itself from the impact of all of these risks.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company in Turkey will be affected by numerous factors beyond its control. The Company's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company 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. The Company'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.

The Company'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 the Company. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries ("OPEC"), governmental regulation, political stability 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. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The CAD/USD and CAD/TL exchange rates also affect the profitability of the Company.

The BOTAS price is a reference price fixed by the Turkish government. The natural gas reference price is correlated to contract prices for natural gas imports into Turkey. Any reduction to the price of imported gas would allow the Turkish government to reduce natural gas subsidies and pay down debt and may not result in a pass-through reduction in the reference price. Weakening of the TL/USD exchange rate has the potential to cause the government gas subsidy to increase. Considering the high natural gas prices in the surrounding region, and the devaluation of the TL against the United States Dollar throughout 2018, the current level of natural gas pricing in Turkey is not expected to decline any further in the near term. There is potential for some of the larger regional natural gas producers such as Iran and Russia to renegotiate more favorable USD priced contracts with the Turkish government. As a result of natural gas infrastructure restrictions and the lack of gas-on-gas competition in Turkey, Valeura does not have the same susceptibility that other producers have to fluctuations in global commodity prices.

Volatility of Commodity Prices

Prices for oil and natural gas fluctuate in response to changes in the supply of and demand for petroleum and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Company’s control. Oil prices are determined by international supply and demand. Factors which affect oil prices include the actions of OPEC, non-OPEC supply growth, world economic conditions, government regulation, political stability throughout the world, the availability of alternative fuel sources and weather conditions. World oil prices are quoted in United States dollars and the price received by the Company is affected by the CAD/USD exchange rate, which will fluctuate over time. Natural gas prices internationally are affected by supply and demand, weather conditions and by prices of alternative sources of energy. Turkish natural gas prices are quoted in TL and the price received by the Company is affected by the CAD/TL exchange rate, which fluctuates over time. Material increases in the value of the CAD may negatively impact production revenues. Such increases may also negatively impact the future value of reserves as determined by independent evaluators.

The impact on the oil and gas industry, in general, from commodity price volatility is significant. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increases in cost during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline. This volatility causes significant variation in net production revenue for the Company from period to period. In an environment of low prices, certain wells or other projects may become uneconomic and the Company may elect not to produce from certain wells, leading to a reduction in development opportunities and the volume and value of reserves.

Volatile oil and gas prices make it difficult to estimate the acquisition value of producing properties and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value.

Capital Requirements

The impact on capital markets caused by investor uncertainty in the global economy has a significant impact on the Company’s business model. The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. There can be no assurance that debt or equity financing will be available or that cash generated by operations will be sufficient to make these expenditures. If debt or equity financing is available, it may not be on terms acceptable to the Company. Failure to obtain such financing on a timely basis could cause the Company to reduce capital spending which would result in reduced production and the potential loss of exploration licences due to a failure to meet drilling deadlines.

Third Party Credit Risk

The Company must successfully market its oil and natural gas to prospective buyers. The Company may be exposed to third party credit risk through its contractual arrangements with its current or future marketers of its oil and natural gas production. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material impact on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital programme, potentially delaying the programme and the results of such programme unless sole risk provisions are available under the joint venture agreements.

Exploration, Development and Production

The long-term commercial success of the Company will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisition or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and 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 wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximising production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, the invasion of water into producing formations, blow-outs, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programmes. Exploration risks are managed by hiring experienced technical professionals and by concentrating the exploration activity on specific core regions that have multi-zone potential where the Company has experience and expertise. The Company is not always able to control these risks when it is a non-operator.

Uncertainty of Reserve Estimates

The process of estimating oil and gas reserves is complex and involves a significant number of assumptions in evaluating available geological, geophysical, engineering and economic data; therefore, reserves estimates are inherently uncertain. To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, many factors and assumptions are incorporated such as expected reservoir characteristics based on geological, geophysical and engineering assessments, future production rates based on historical performance and expected future operating and investment activities, future oil and gas prices and quality differentials, future development and operating costs and assumed effects of regulation by government agencies.

Properties will, over a period of time, actually deliver oil and natural gas in quantities different than originally estimated due to changes in reservoir performance. The timing of future capital expenditures is subject to uncertainty. Projected future commodity prices and the operating and capital cost structure are subject to significant management judgment and currently, highly volatile. Actions by foreign governments to alter their respective royalty and tax regimes may have a significant and unpredictable impact.

Environment, Health and Safety

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 federal, provincial and local laws and regulations. In international jurisdictions, 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. 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 of applicable environmental legislation 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 the Company to incur costs to remedy such discharge. There are potential risks to the environment inherent in the business activities of the Company.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively 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 the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company 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 any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Short Production Test Rates

The short production test rates disclosed in this MD&A 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 has been measured. Initial on-stream production rates are not necessarily indicative of long-term performance or ultimate recovery. To date, Valeura's shallow gas conventional wells and fracked unconventional tight gas wells have exhibited relatively high decline rates at more than 50% and 75%, respectively, in their first year of production.

There is currently no long-term flow information for the deep, unconventional BCGA. While the same geological formations that are producing gas in the shallow are being targeted in the deep, unconventional play, they are in a different depth and pressure environment and the type curves are not expected to be indicative of deep, unconventional well production rates. A pressure transient analysis or well-test interpretation has not been carried out in respect of the production tests on the Yamalik-1 well. All natural gas rates and volumes are presented net of any load fluids.

Forward-looking Statements

Certain information included in this MD&A constitutes forward-looking information under applicable securities legislation. Such forward-looking information is for the purpose of explaining management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", "target" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this MD&A includes, but is not limited to: the 2019 work programme and capital budget; the timeliness and costs for the deep drilling programme in 2019; the identification and finalisation of locations for the third well of the deep programme; the ability to determine the source of water production from Yamalik-1; testing results from Inanli-1 and the timing of completion operations with respect thereto; the timing of the delineation drilling campaign; the timing of fracking and testing Inanli-1, the timing of fracking and testing operations for Devepinar-1; the assessment of resources in the test formations; the potential of a basin-centered gas play in the Thrace Basin; management's belief regarding the potential of the Company's deep basin-centred gas play and shallow gas business in the Thrace Basin; the Company's belief in the pervasiveness of over-pressured gas across the Company's Thrace Basin lands; the Company's expectation that it will maintain operatorship of the deep rights on the Banarli Lands and West Thrace Lands during most of 2019 and through the drilling, completion and testing of the three well appraisal program; the Company's commitment to safety, environmentally responsible practices and optimising operational and administrative functions; the Company's business strategy and outlook, operational plans, and expected capital expenditures; and the availability of operating cash flow and the ability to finance development through 2020 from existing working capital and operating cash flow.

Forward-looking information is based on management's current expectations and assumptions regarding, among other things: political stability of the areas in which the Company is operating and completing transactions, and in particular the period of political change and uncertainty in Turkey from 2016 to 2018; continued safety of operations and ability to proceed in a timely manner; continued operations of and approvals forthcoming from the Turkish government in a manner consistent with past conduct; future seismic and drilling activity on the expected timelines; the prospectivity of the TBNG JV Lands and Banarli Licenses, including the deep potential; the continued favourable pricing and operating netbacks in Turkey; future production rates and associated operating netbacks and cash flow; decline rates; future sources of funding; future economic conditions; future currency exchange rates; the ability to meet drilling deadlines and other requirements under licences and leases; and the Company's continued ability to obtain and retain qualified staff and equipment in a timely and cost efficient manner. In addition, the Company's work programmes and budgets are in part based upon expected agreement among joint venture partners and associated exploration, development and marketing plans and anticipated costs and sales prices, which are subject to change based on, among other things, the actual results of drilling and related activity, availability of drilling, fracking and other specialised oilfield equipment and service providers, changes in partners' plans and unexpected delays and changes in market conditions. Although the Company believes the expectations and assumptions reflected in such forward-looking information are reasonable, they may prove to be incorrect.

Forward-looking information involves significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a 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 of currency fluctuations; changes in gas prices and netbacks in Turkey; uncertainty regarding the contemplated timelines and costs for the deep evaluation; 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 or civil unrest in Turkey; potential changes in laws and regulations, the uncertainty regarding government and other approvals; counterparty risk; risks associated with weather delays and natural disasters; and the risk associated with international activity. The forward-looking information included in this news release is expressly qualified in its entirety by this cautionary statement. The forward-looking information included herein is made as of the date hereof and Valeura assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law. See the 2018 AIF for a detailed discussion of the risk factors.

The forward-looking information contained in this MD&A is made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward looking information contained in this MD&A is expressly qualified by this cautionary statement.