PetroShale

Calgary • Denver

Management's Discussion & Analysis

As at June 30, 2017
and for the three and six months ended June 30, 2017 and 2016

MANAGEMENT'S DISCUSSION & ANALYSIS

The following Management's Discussion and Analysis (the "MD&A") has been prepared by management and reviewed and approved by the Board of Directors of PetroShale Inc. ("PetroShale" or the "Company") on August 17, 2017. This MD&A reports on the consolidated financial position and the consolidated results of operations of PetroShale for the three and six months ended June 30, 2017 and 2016 and should be read in conjunction with PetroShale's consolidated interim financial statements as at and for the three and six months ended June 30, 2017 and the consolidated financial statements as at and for the year ended December 31, 2016. The reader should be aware that historical results are not necessarily indicative of future performance.

The financial data presented below has been prepared in accordance with International Financial Reporting Standards ("IFRS"), unless otherwise indicated.

Frequently Used Terms:

Term	Description
Bbl	Barrel(s)
Boe	Barrel(s) of oil equivalent
Mboe	Thousand barrels of oil equivalent
Mcf	Thousand cubic feet
NGLs	Natural gas liquids
WTI	West Texas Intermediate, reference price paid in US$ for crude oil of standard grade
HH	Henry Hub, reference price paid in US$ for natural gas deliveries

Barrel of Oil Equivalent

Where amounts are expressed on a Boe basis, natural gas volumes have been converted to Boe using a ratio of 6,000 cubic feet of natural gas to one barrel of oil (6 Mcf : 1 Bbl). This Boe conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The value ratio between the commodities, based on the current price of crude oil compared to natural gas, is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, and therefore utilizing this conversion ratio may be misleading as an indication of value.

Presentation of Volumes and Currency

Production volumes and per Boe calculations are presented on a gross working interest basis, before royalty interests, unless otherwise stated. PetroShale's reporting and measurement currency is the Canadian dollar. Amounts in this MD&A are in Canadian dollars unless otherwise stated. The functional currency of PetroShale's US subsidiary is the US dollar, and the US subsidiary's results and balance sheet are translated to Canadian dollars for purposes of consolidation in PetroShale's financial statements, in accordance with the Company's foreign currency translation accounting policy.

Non-IFRS Measurements

The MD&A contains the terms "funds flow from operations," "operating netback" and "EBITDA" which are not defined by IFRS and therefore may not be comparable to performance measures presented by others. Funds flow from operations represents cash flow from operating activities prior to change in non-cash working capital and decommissioning expenditures. Operating netback represents revenue and realized gain or loss on financial derivatives, less royalties, production taxes and operating costs and has been presented on a per Boe basis. EBITDA means net income (loss) before taxes, depletion and depreciation expense, exploration and evaluation expense, any impairments, finance expense, foreign exchange gain or loss, any gain or loss on property dispositions, share-based compensation expense and unrealized gain or loss on financial derivatives. Management believes that in addition to net income (loss) and cash flow from (used in) operating activities, funds flow from operations, operating netback and EBITDA are useful supplemental measures as they assist in the determination of the Company's operating performance, leverage and liquidity. Investors should be cautioned, however, that these measures should not be construed as an alternative to either net income (loss) or cash flow from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

The reconciliation between funds flow from operations and EBITDA and cash flow from operating activities and net loss, respectively can be found later within this MD&A. Please refer to note 2 to the consolidated interim financial statements which describes a change in accounting policy, effective June 30, 2017, affecting cash flows from operating activities under IFRS, and as a result, funds flow from operations.

MANAGEMENT'S DISCUSSION & ANALYSIS

Forward Looking Statements

This MD&A contains forward looking statements and forward-looking information (collectively, "forward looking statements") within the meaning of applicable Canadian securities laws. Management's assessment of future plans and operations, drilling plans and the timing thereof, plans for the tie-in and completion of wells and the timing thereof, capital expenditures, timing of capital expenditures and methods of financing capital expenditures and the ability to fund financial liabilities, use of proceeds from any equity offering, production estimates, expected commodity mix and prices, reserve estimates, future operating costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds flow from operations and the timing of and impact of implementing new accounting policies, estimates regarding its undeveloped land position, expected changes to amounts and terms of available debt financing and estimated future drilling, recompletion or reactivation activities and anticipated impact upon PetroShale's forecasts in respect of production and cash flow for the remainder of 2017 and the resulting fiscal year end net debt may constitute forward looking statements and necessarily involve risks including, without limitation, risks associated with oil and gas development, exploitation, production, marketing and transportation of oil and natural gas, loss of markets, volatility of commodity prices, currency fluctuations, inability to transport or process natural gas at economic rates or at all, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services at reasonable costs or at all, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions or drilling operations, risks associated with PetroShale's non-operated status on some of its properties, production delays resulting from an inability to obtain required regulatory approvals or the tie-in of associated natural gas production and an inability to access sufficient capital from internal and external sources.

The Company's actual results may differ materially from those expressed in, or implied by, the forward looking statements. Forward looking statements or information is based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although PetroShale believes that the expectations reflected in such forward looking statements or information 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 document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic, regulatory and political environment in which PetroShale operates; the ability of the Company to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the Company and the operators of its non-operated properties to operate in the field in a safe, efficient, compliant and effective manner; PetroShale's ability to obtain financing on acceptable terms or at all; changes in the Company's various credit facilities including changes to borrowing capacity and maturity dates; receipt of regulatory approvals; field production rates and decline rates; the ability of the Company, and the operators of its non-operated properties, to tie-in associated natural gas production in an economic manner, or at all; the ability to manage operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the ability to convert non-producing proven or probable oil and natural gas reserves to producing reserves; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate transportation for commodity production; future petroleum and natural gas prices; currency exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; PetroShale's ability to successfully drill, complete and commence production at commercial rates from its operated well(s); and PetroShale's ability, or those of the operators of its non-operated properties, to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the System for Electronic Document Analysis and Retrieval ("SEDAR") website (www.sedar.com) or at the Company's website (www.petroshaleinc.com). Furthermore, the forward looking statements contained in this document are made as at the date of this document and the Company does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(all $ amounts are presented in Canadian dollars)	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
FINANCIAL *(in thousands, except per share and share data)*				
Oil and natural gas revenue	$ 10,786	$ 5,966	$ 25,964	$ 9,970
Funds flow from operations (1)	$ 4,551	$ 2,734	$ 12,581	$ 4,032
Net loss	$ (847)	$ (2,947)	$ (757)	$ (6,427)
Per share - basic and diluted	$ (0.01)	$ (0.09)	$ (0.01)	$ (0.19)
EBITDA (1)	$ 4,480	$ 2,594	$ 12,510	$ 3,512
Capital expenditures	$ 15,674	$ 7,089	$ 17,619	$ 13,315
Net debt(2)			$ 49,495	$ 126,177
Common shares outstanding			156,857,189	34,207,574
Weighted average - basic and diluted	143,070,672	34,207,574	88,939,850	34,207,574
OPERATING				
Number of Days	91	91	181	182
Daily production(4)				
Crude oil (Bbls)	1,910	1,228	2,281	1,211
Natural gas (Mcf)	3,964	2,832	3,658	2,098
Barrels of oil equivalent (Boe)	2,571	1,700	2,890	1,560
Average realized price (3)				
Crude oil ($/Bbl)	$ 56.87	$ 49.00	$ 58.26	$ 41.70
Natural gas ($/Mcf)	$ 2.49	$ 1.91	$ 2.89	$ 2.04
Netback per Boe ($) (1)(3)				
Revenue	$ 46.10	$ 38.58	$ 49.63	$ 35.10
Royalties	$ (9.53)	$ (7.82)	$ (10.30)	$ (7.15)
Operating costs	$ (9.01)	$ (6.68)	$ (8.01)	$ (7.86)
Production taxes	$ (3.42)	$ (2.97)	$ (3.69)	$ (2.71)
Operating netback	$ 24.14	$ 21.11	$ 27.63	$ 17.38
Operating netback, on a net of royalty basis	$ 30.40	$ 26.49	$ 34.86	$ 21.86

(1) Non-IFRS measure - See page 2 and the tables under "Non-IFRS Measures" at the end of this MDA.

(2) Total liabilities, excluding decommissioning obligation, less total current assets, excluding any unrealized value of financial derivative instruments.

(3) The Company had no realized gains or losses on hedge contracts in effect during these periods.

(4) Our oil and natural gas reserves have been categorized as Tight Oil and Shale Gas pursuant to National Instrument 51-101 and the required disclosure included in our Annual Information Form. We have used the terms "crude oil" and "natural gas" here and throughout this MDA as we feel they are easily understood by users and consistent with disclosure of our peers.

MANAGEMENT'S DISCUSSION & ANALYSIS

DESCRIPTION OF BUSINESS

PetroShale Inc. (the "Company") is an oil company engaged in the acquisition, development and consolidation of interests in the North Dakota Bakken/Three Forks.

SECOND QUARTER 2017 SIGNIFICANT EVENTS

Oil and Gas Lease Development

During the quarter, production increased, year over year, due to the completion of the Company's first operated well and three non-operated wells in December of 2016. Average production in the second quarter was 2,571 Boe per day, an increase of 38% from the fourth quarter of 2016 and an increase of 51% from the corresponding period in 2016.

In June, the Company closed an acquisition of significant undeveloped acreage and approximately 100 Boe per day of existing production in its core focus area. The acquisition also resulted in a second operated drilling unit for PetroShale.

Bank Facility Extension

Subsequent to June 2017, the Company's senior lender agreed to increase PetroShale's borrowing capacity under its senior credit facility from US$30.9 million to US$39.9 million after its year-end review of the Company's reserve report. In addition, the renewal date of the facility was extended to June 30, 2018 at which time the facility will either be further extended, or converted to a term facility with a term of 12 months.

Oil Prices

World oil prices weakened in the second quarter, with WTI averaging US$48. PetroShale generated a netback of $24.14 / Boe ($30.40 / Boe on a net of royalty basis) during the second quarter, an increase of 14% from $21.11 / Boe ($26.49 / Boe on a net of royalty basis) in the corresponding period of 2016.

Equity Offering

The Company completed a marketed equity offering of 122,265,000 common shares at $0.90 per share during the second quarter, generating net proceeds of approximately $106 million. Proceeds were used to fully repay previously deferred interest and fees on the subordinated loan and to initially repay principal amounts outstanding under both the subordinated loan and senior loan. Currently, the Company has approximately US$13.0million and US$67.1 million undrawn capacity under its senior loan and subordinated loans, respectively, and intends to use the undrawn capacity under these facilities to fund the Company's drilling and land acquisition program.

OUTLOOK

The Company is in the process of preparing to drill four gross (3.5 net) wells on its two operated drilling units in the latter half of 2017, and is also participating in eleven gross (1.7 net) non-operated wells. We anticipate these wells to be completed and placed into production between now and the end of the first quarter of 2018.

RESULTS OF OPERATIONS

Note: All $ amounts reflected throughout this management's discussion and analysis are in Canadian dollars, unless stated otherwise, consistent with the presentation of the Company's consolidated financial statements. All production volumes and per Boe amounts are on a working interest (gross of royalty) basis unless otherwise stated.

Production

The following table summarizes the Company's working interest daily production volumes for the relevant periods.

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Crude oil (Bbl per day)	1,910	1,228	2,281	1,211
Natural gas and NGLs (Mcf per day)	3,964	2,832	3,658	2,098
Total (Boe per day)	2,571	1,700	2,890	1,560
Liquids % of Production	84%	81%	88%	84%

Production for the quarter is up 51% from the same quarter in 2016 due to the Company's drilling program, the majority of which related to the operated and non-operated wells which commenced production in December 2016. We anticipate a decrease in production volumes in the third quarter of 2017 due to natural declines from these new wells. The Company's proportionate liquids production increased compared to previous periods as the Company's recently completed operated well has not yet been tied into natural gas capture and transportation facilities. We anticipate that will occur by the end of the year.

Pricing

Average benchmark prices	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Crude oil – WTI (US$ per Bbl)	$ 48.24	$ 45.46	$ 50.00	$ 39.55
Natural gas – HH (US$ per Mcf)	3.08	2.15	3.05	2.07
Exchange rate (US$ /CAD$)	1.35	1.29	1.33	1.33

Realized prices (CAD)				
Crude oil ($ per Bbl)	$ 56.87	$ 49.00	$ 58.26	$ 41.70
Natural gas and NGLs ($ per Mcf)	2.49	1.91	2.89	2.04
Per Boe	$ 46.10	$ 38.58	$ 49.63	$ 35.10

Realized prices (USD)				
Crude oil ($ per Bbl)	$ 42.27	$ 38.01	$ 43.71	$ 31.55
Natural gas and NGLs ($ per Mcf)	1.84	1.49	2.16	1.55
Per Boe	$ 34.23	$ 29.95	$ 37.22	$ 26.60

Management analyzes the basis differential between WTI and the actual realized price for the sale of our crude oil as WTI is a reasonable proxy for the market in which our oil is sold. The average differential between the Company's realized crude price to WTI during the three months ended June 30, 2017 was US$5.97 per Bbl, which has decreased from US$7.45 per Bbl in the same period in 2016 and from US$6.86 per Bbl in the first quarter of 2017. The Company believes that with the recent completion and commissioning of the Dakota Access Pipeline, Bakken oil price differentials have narrowed as takeaway capacity has increased. Realized oil prices in the three month period ended June 30, 2017 improved significantly compared to the same period in 2016 mainly due to higher WTI benchmark prices as well as improved differentials but have declined from the first quarter ($59.27 and US$44.76) mainly due to lower WTI prices. Realized natural gas prices have improved over the corresponding 2016 period, primarily due to improved benchmark market prices for natural gas and better natural gas products pricing in the regional market, but overall remain challenged given gas capture requirements and limited pipeline and processing accessibility.

The Company currently has no outstanding commodity price hedging contracts in place.

Royalties

	Three months ended June 30, 2017	Three months ended June 30, 2016	Six months ended June 30, 2017	Six months ended June 30, 2016
Royalties (in thousands)	$ 2,229	$ 1,209	$ 5,387	$ 2,031
Royalties per Boe	$ 9.53	$ 7.82	$ 10.30	$ 7.15
Royalties as % of Revenue	20.7%	20.3%	20.7%	20.4%

The average effective royalty rate has remained consistent quarter over quarter. The royalties per Boe amount is higher for the three and six months ended June 30, 2017 due to the higher realized revenue per Boe in the period. Royalty expense is higher, on an absolute dollar basis, in the second quarter compared to the same period in 2016, due to higher overall revenues. Management anticipates the average effective royalty rate to remain consistent in future periods.

Operating Costs and Production Taxes

	Three months ended June 30,		Six months ended June 30,	
	2017	**2016**	**2017**	**2016**
Operating costs	$ 2,108	$ 1,033	$ 4,190	$ 2,232
Production taxes	801	460	1,932	770
Operating costs and production taxes (in thousands)	$ 2,909	$ 1,493	$ 6,122	$ 3,002
Operating costs per Boe	$ 9.01	$ 6.68	$ 8.01	$ 7.86
Production taxes per Boe	3.42	2.97	3.69	2.71
Operating costs and production taxes per Boe	$ 12.43	$ 9.65	$ 11.70	$ 10.57

Operating costs

Operating costs per Boe for the quarter ended June 30, 2017 were higher than the first quarter of 2017 ($7.20 / Boe) and the comparative quarter in 2016 due to certain assets in our core area being shut-in temporarily for repair workovers and the costs of those workovers being spread over a smaller production volume.

Production taxes

North Dakota charges a 5% oil severance tax and a 5% oil extraction tax on net royalty volumes. Production taxes per Boe for the three months ended June 30, 2017 reflect the impact of higher realized prices and are consistent quarter over quarter as a percentage of revenue. Management anticipates production taxes to be consistent as a percentage of revenue on a go forward basis.

Operating Netback

	Three months ended June 30,		Six months ended June 30,	
($ per Boe)	**2017**	**2016**	**2017**	**2016**
Revenue	$ 46.10	$ 38.58	$ 49.63	$ 35.10
Royalties	(9.53)	(7.82)	(10.30)	(7.15)
Operating costs	(9.01)	(6.68)	(8.01)	(7.86)
Production taxes	(3.42)	(2.97)	(3.69)	(2.71)
Operating netback	$ 24.14	$ 21.11	$ 27.63	$ 17.38
Operating netback on a net of royalty basis	$ 30.40	$ 26.49	$ 34.86	$ 21.86

Our operating netback increased substantially for the three months and six months ended June 30, 2017 compared to the corresponding prior period due to the improved pricing environment and lower oil price differential.

General and Administrative Expense

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Gross general and administrative expense	$ 1,231	$ 670	$ 2,009	$ 1,425
Capitalization of internal development costs	(62)	-	(62)	-
Costs charged to operated properties	(1)	-	(2)	-
Net general and administrative expense (in thousands)	$ 1,168	$ 670	$ 1,945	$ 1,425

General and administrative expense ("G&A") increased during the three months ended June 30, 2017 compared to the three months ended June 30, 2016 and March 31, 2017 ($777,000) due to one-time costs associated with personnel changes and higher transaction and legal costs associated with the land acquisition closed in June and the new senior loan agreement.

Depletion and Depreciation Expense

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Depletion and depreciation expense (in thousands)	$ 3,429	$ 2,391	$ 7,463	$ 4,378
Depletion and depreciation per Boe	$ 14.66	$ 15.46	$ 14.26	$ 15.42

Depletion and depreciation expense increased during the three and six months ended June 30, 2017 compared to the prior comparable periods, due to higher production volumes. The expense per Boe decreased in the three months ended June 30, 2017 compared to the corresponding prior period due to reserve additions in the Company's December 31, 2016 independent reserve report *(the "NSAI Report").*

Finance Expense

Finance expense reflects interest on the Company's senior and subordinated credit facilities, including the amortization of certain loan origination and other fees. Interest cost reflects both cash paid interest on the senior credit facility and deferred interest on the subordinated credit facility during the first three months of the year. Finance expense for the three months ended June 30, 2017 ($1.9 million) decreased over the comparative period in 2016 ($3.3 million) due to significant repayment of debt following completion of the Company's equity offering in April. Interest payments on the Company's subordinated credit facility had been deferred from April 1, 2015 through March 31, 2017 and reflected in accounts payable and accrued liabilities on the statements of financial position. Following completion of the equity financing, we have re-commenced cash interest payments on the subordinated credit facility starting in April 2017. Interest costs will likely increase in the third quarter due to the financing of the land acquisition completed in June.

Impairment

Management evaluates its developed and producing assets ("D&P") for impairment indicators that suggest the carrying value of a cash generating unit ("CGU") may not be recoverable. If such impairment indicators exist, any impairment is determined by comparing the carrying amount of the CGU to the greater of the CGU's value in use ("VIU") and its estimated fair value less selling costs. If the carrying amount is in excess of the estimated recoverable value, then the Company will record an impairment expense related to the CGU. During the three months ended June 30, 2017, management determined that no impairment indicators existed. Despite the current weakness in WTI prices, our recent production and reserves increases support a lack of impairment.

Share-based Compensation

Share-based compensation expense reflects the value ascribed to stock options provided to employees, consultants and directors of the Company, utilizing a fair value methodology, and amortization of those amounts over the anticipated period in which the options vest. Share-based compensation expense was $87,000 for the three months ended June 30, 2017 compared to $22,000 for the three months ended June 30, 2016. The increase in expense year over year is due to the grant of 1,350,000 stock options in July 2016.

Foreign Currency Gain and Translation Adjustment

The Company's consolidated financial statements are reported in Canadian dollars, which is the Company's presentation currency. Transactions of the Company's US subsidiary are recorded in US dollars, its functional currency, as this is the primary economic environment in which the subsidiary operates. The assets, liabilities and results of operations of the Company's US subsidiary are translated to Canadian dollars in the consolidated financial statements according to the Company's foreign currency translation policy, with any corresponding gain or loss reflected as currency translation adjustment in other comprehensive income. The Company experienced a small currency translation loss of $2.4 million for the three months ended June 30, 2017 due to the strengthening of the Canadian dollar to the US dollar from March 31, 2017 (US dollar / Canadian dollar 1.33) to June 30, 2017 (US dollar / Canadian dollar 1.30). The US dollar / Canadian dollar average exchange rate was 1.35 for the three months ended June 30, 2017 compared to the average exchange for the three months ended June 30, 2016 of 1.29.

Share Capital

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Weighted average common shares outstanding:				
Basic and diluted	143,070,672	34,207,574	88,939,850	34,207,574
Outstanding securities:				
Common shares, voting and non-voting			156,857,189	34,207,574
Stock options			2,736,736	2,295,205
Warrants (exercise price of $0.75)			2,000,000	2,000,000

As at August 17, 2017, we had 157,097,767 common shares, 2,496,158 stock options and 2,000,000 common share purchase warrants outstanding.

The following stock options are outstanding as at June 30, 2017:

Stock Options

Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Number of Outstanding Options	Number of Options Exercisable
$0.70	2.96	2,293,264	943,264
$1.50	0.17	443,472	443,472
$0.83	2.51	2,736,736	1,386,736

Capital Expenditures

The following table represents capital expenditures for the six months ended June 30, 2017:

(in thousands)	
Capital expenditures	
Acquisitions	$ 12,856
Drilling and completion	4,763
Total capital expenditures	$ 17,619

During the six months ended June 30, 2017, the Company participated in 54 gross (1.4 net) non-operated wells, which were in various stages of completion.

The Company has no commitments to make additional capital expenditures. We estimate future development costs of US$263.1 million related to our proven and probable reserves as at June 30, 2017.

Liquidity and Capital Resources

Capital expenditures of $17.6 million for acquisitions and drilling and completion activities for the six months ended June 30, 2017, were financed indirectly through proceeds from equity offerings, draws on the Company's subordinated credit facility, cash on hand and operating cashflow.

During our initial stages of growth, the Company is dependent on cash on hand, cash flows and equity and debt issuances to finance capital expenditures and property acquisitions. The Company will manage borrowings in relation to our credit capacity and our ability to generate future operating cash flows to service such debt.

The Company continuously monitors production, commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing its capital spending levels by not consenting to participate in additional drilling proposed by operators of its various properties or by selling PetroShale's interest in those wells to other parties. The operators of the Company's properties continue to evaluate their capital programs in light of current commodity prices. Although drilling activity remains low, completion activity has increased from their lows in mid-2016 as oil prices have steadied. The Company will monitor its financial capacity before proceeding with additional wells on its operated lands. Accounts payable and accrued liabilities consist of amounts relating to capital spending, field operating activities and general and administrative expenses. Management expects to be able to fully meet all current obligations when due with funding provided by a combination of accounts receivable collections, funds flow from operations and available capacity under our credit facilities.

The Company maintains a senior revolving credit facility which is referred to as the senior loan in the statements of financial position. The current capacity of this facility is US$39.9 million. The maturity date is currently June 30, 2018, at which point, the facility will either be extended or, at the option of the lender, converted to a non-revolving facility for a term of 12 months. The amount of the facility is subject to a borrowing base test performed on a periodic basis and at least twice annually by the lender, based primarily on producing oil and natural gas reserves and using commodity prices estimated by the lender as well as other factors. The next scheduled borrowing base review is scheduled to be completed before the end of October 2017. A decrease in the borrowing base determined by the senior lender could result in a reduction to the credit facility, which may require a repayment to the lender.

The senior loan facility is subject to certain financial and non-financial covenants. The financial covenants consist of: (i) a consolidated cash flow to interest expense ratio, as defined in the loan agreement, which is not to be less than 2.50 to 1 on a rolling four-quarter basis; and (ii) a requirement that the ratio of the senior loan amount to EBITDA, on a rolling four quarter basis, not exceed 3.0 to 1. The consolidated cash flow to interest expense ratio is calculated on the basis that interest expense reflects cash interest paid and excludes deferred and unpaid interest on the subordinated credit facility and other non-cash amortization expense included in finance expense on the company's statements of operations. Consolidated cash flow is defined as consolidated net income plus finance expense, taxes, and other non-cash expenses, adjusted to reflect the pro forma effects of asset acquisitions and dispositions, plus the proceeds of any equity issued by the Company. The consolidated cash flow to interest expense ratio at June 30, 2017 was 9.9 to 1, and the senior loan to EBITDA ratio was 0.6 to 1. As a result, the Company is in compliance with the financial covenants as at that date, and is also in compliance with all of the other covenants under the senior loan as at June 30, 2017. This facility was drawn to approximately US$8.8 million as at June 30, 2017.

The Company also has a secured, subordinated revolving credit facility. The facility is intended to allow the Company to close acquisitions and/or fund drilling and well completion capital expenditures. The credit facility bears interest at a rate of 12% per annum and includes a 2.5% origination fee. The credit facility is provided by two significant shareholders of the Company, one of whom is also the executive Chairman of the Board of Directors. The subordinated loan was drawn to US$30.9 million, as at June 30, 2017, of the current available capacity of US$80.0 million. The terms of the subordinated loan are similar to those which management believes could be negotiated with third parties.

The Company closed an equity offering in April 2017 which generated net proceeds of approximately $106 million, which was used to fully repay deferred interest on the subordinated loan and to partially repay principal amounts outstanding under both the subordinated loan and senior loan. Following completion of the equity offering, settlement of the deferred interest and a portion of the principal balances under both the senior and subordinated loan, the Company has re-commenced paying interest on the subordinated loan. The Company anticipates that it will be able to meet its financial covenants under the senior loan and meet its other financial obligations following completion of the equity offering and the recent increase in production and operating cash flows.

Contractual Obligations

The Company is, or will be, obligated to pay various costs associated with operations incurred in the normal course of business. These costs include royalties paid to governments or mineral rights owners, surface lease rentals and decommissioning obligations. These costs are highly dependent on the future operating environment and are subject to changes in commodity prices, ownership, production volumes and government policies.

Letter of Credit

The Company has an outstanding letter of credit in favor of the energy regulator in North Dakota in the amount of US$75,000. As security, the Company has set aside an equivalent amount in cash at the financial institution that issued the letter of credit. In addition, the Company has advanced funds to other regulatory agencies of US$125,000 as security in order to operate in North Dakota.

Related Party Transactions

Related party transactions are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The Company has a secured, subordinated, revolving credit facility which may be drawn in US dollars and which has a capacity of US$80.0 million and a maturity date of December 31, 2017. The credit facility is provided by two significant shareholders of the Company, one of whom is the executive Chairman of our Board of Directors. During the six months ended June 30, 2017, fees and the value of the warrants associated with this facility were amortized to finance expense in the amount of $367,000. Subsequent to completion of the equity financing, cash interest payments re-commenced on this facility after having been deferred since April 1, 2015. In May 2016, as partial consideration for extending the term of the subordinated loan, increasing the facility capacity and agreeing to continue to defer cash interest payments, the Company granted 2 million common share purchase warrants to the subordinated lenders, pro rata to their participation in the revised commitment amount. Each warrant entitles the holder to acquire one common share at $0.75 for a period of two years. These warrants were valued at $684,000 on the date of issuance and reflected in shareholders' equity on the statements of financial position.

Summary of Quarterly Results

Three month period ended (in thousands):	6/30/2017	3/31/2017	12/31/2016	9/30/2016	6/30/2016	3/31/2016	12/31/2015	9/30/2015
Oil and natural gas sales, net of royalties	$ 8,557	$ 12,020	$ 6,041	$ 4,497	$ 4,757	$ 3,182	$ 4,409	$ 5,839
Cash flow from operations	9,350	3,960	2,021	3,960	1,076	2,817	2,841	2,776
Net income (loss)	(847)	90	(3,048)	(3,387)	(2,947)	(3,480)	(1,543)	(3,042)
Net income (loss) per share –Basic and diluted	$ (0.01)	$ 0.00	$ (0.09)	$ (0.10)	$ (0.09)	$ (0.10)	$ (0.05)	$ (0.09)

Factors that influenced quarterly variations

Quarter over quarter fluctuations are attributable to the items discussed below. Stabilizing production on new wells and lower WTI prices resulted in the decreased sales in the three months ended June 30, 2017. Cash flow from operations increased due to a reduction in non-cash working capital and lower finance expense. The first quarter of 2017 saw significant increased production volumes which resulted in increased sales which, along with lower operating costs, produced positive net income for the quarter ended March 30, 2017 and an improvement in cash flow from operations. During the quarter ended December 31, 2016, higher production volumes, higher realized prices and lower general and administrative expenses were slightly offset by higher finance expense and higher depletion expense. Net loss for the quarter ended September 30, 2016 increased from the prior quarter due to lower production volumes and higher finance expense offset by lower depletion and general and administrative expenses. Net loss for the quarter ended June 30, 2016 decreased from the prior quarter due to increased production volumes and realized prices and lower operating costs. For the quarter ended March 31, 2016, net revenue decreased as production volumes declined combined with lower realized commodity prices. The production decline was due to the shut in of several previously producing wells adjacent to wells in the process of being completed. The net loss in that quarter reflects the impact of lower oil prices and higher finance expense. For the quarter ended December 31, 2015, net revenue decreased as production volumes declined combined with slightly lower realized commodity prices. The quarter ended September 30, 2015 reflected a larger loss arising from higher depletion and finance expenses and lower commodity prices.

Cash flow from operating activities generally increased or decreased during the periods presented in a manner consistent with changes in revenues, except in the quarters ended June 30 and December 31, 2016 and June 30, 2017 where the impact of changes in non-cash working capital offset the impact of changes in operating results.

Generally, the Company has made several acquisitions and participated in drilling programs which have generally increased production volumes over the past 24 months.

Critical Accounting Estimates

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. Estimates and underlying assumptions are reviewed on an ongoing basis. Actual results may differ from these estimates.

Reserves

The estimation of oil and natural gas reserves is critical to various accounting estimates. It requires various judgments based on available geophysical, geological, engineering and economic data. These estimates can change materially as information from ongoing exploratory, development and production activities becomes available. These estimates can also change as economic conditions impacting crude oil and natural gas prices, royalties and operating costs change. Reserve estimates can change net income (loss) through their impact on depletion expense, accretion expense from decommissioning obligations and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income (loss). The Company obtains an independent engineering report annually, with the latest being as at December 31, 2016.

Decommissioning obligation

The calculation of the decommissioning obligation in the statements of financial position is based on estimated costs to abandon and reclaim the Company's net ownership in all wells and facilities, the estimated timing of the costs to be incurred and economic inflation and discount rates. These estimates can be impacted by technological advances, changes in laws and regulations or economic conditions and can impact the amount of the decommissioning obligation and net income (loss) through depletion and depreciation expense and accretion reflected as finance expense in the statement of operations.

Business combinations

In accounting for an acquisition, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired. The amounts allocated to PP&E and decommissioning obligations can have an impact on depletion and depreciation expense, future impairments (if any) and accretion expense.

Share-based compensation

The calculation of share-based compensation expense includes estimates of future interest rates, forfeiture rates, stock price volatility and the expected timing of exercise of stock options. These estimates can impact net income (loss) and contributed surplus.

Warrants

In accounting for warrants issued, management is required to make estimates of future interest rates and stock price volatility. These estimates can change the amount recorded to warrants in the statement of financial position as well as finance expense and net income (loss) in the statement of operations.

Deferred income taxes

The calculation of deferred income taxes includes estimates of timing of reversal of temporary differences, tax rates substantively enacted and likelihood of assets being realized. These estimates can impact net income (loss) and deferred tax assets and liabilities.

New and Future Accounting Pronouncements

IFRS 9 – "Financial Instruments" is the result of the first phase of the IASB's project to replace IAS 39 – "Financial Instruments: Recognition and Measurements". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. This standard will come into effect on January 1, 2018 with early adoption permitted. The extent of the impact of the adoption of IFRS 9 is not expected to be material.

IFRS 15 – "Revenue from Contracts with Customers" was issued in May 2014 to replace IAS11 – "Construction Contracts" and IAS 18 – "Revenue" and related interpretive guidance. IFRS 15 provides a single, principles based model to be applied to all contracts with customers as well as new disclosure requirements with the objective of a more structured approach, improving comparability across entities and industries. Under IFRS 15, an entity will recognize revenue at the amount to which it expects to be entitled in exchange for goods or services on their transfer. IFRS 15 is effective for annual periods beginning on or after January 1, 2018 with earlier adoption permitted and is to be applied retrospectively. The extent of the impact of the adoption of IFRS 15 on the Company has not been fully assessed at this time.

IFRS 16 – "Leases" is effective for annual periods beginning on or after January 1, 2019 with earlier adoption permitted, and is to be applied retrospectively. The extent of the impact of adoption of this new standard on the Company has not been fully assessed at this time.

IAS 38 – amends the existing standard "Clarification of Acceptable Methods of Depreciation and Amortization" and is effective for periods beginning January 1, 2018. The extent of the impact of the implementation of these changes is not anticipated to be material.

Business Conditions and Risks

The Company is engaged in the acquisition, exploration, development and production of crude oil and natural gas. The Company's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates, and the ability to access debt and equity financing at a reasonable cost, or at all. Operational risks include the performance of the Company's properties, competition for land and services, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns, and reliance on the operators of a portion of the Company's properties.

When acquiring land, the Company uses technical and industry knowledge to evaluate potential hydrocarbon plays in order to pay what it believes are economically sound prices that will benefit PetroShale's shareholders. The Company's focus is on areas in which the prospects are understood by management.

The Company minimizes operational risks by participating with well-established operators of our non-operated properties, and by engaging experienced service providers on our operated properties. Because we do not operate a portion of our existing US properties we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of the Company's non-operated properties to adequately perform operations, an operator's breach of the applicable agreements or regulations or an operator's failure to act in ways that are in the Company's best interests could reduce production and revenues or could create a liability for the Company for the operator's failure to properly maintain wells and facilities or to adhere to applicable safety and environmental standards. With respect to properties that the Company does not operate:

- The operator could refuse to initiate exploration or development projects;
- If the Company proceeded with any of those projects the operator has refused to initiate, PetroShale may not receive any funding from the operator with respect to that project and thus bear all the risk;
- The operator may initiate exploration or development projects on a different schedule than the Company would prefer, possibly resulting in lease expirations.
- The operator may propose greater capital expenditures, or on a different schedule than the Company anticipated, including expenditures to drill more wells or build more facilities on a project than the Company has funds for, which may mean that the Company cannot participate in those projects or participate in a substantial amount of the revenues from those projects; and
- The operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect anticipated exploration and development activities carried out on its properties which the Company does not operate, and the results of those activities.

PetroShale's focus is on areas and geological formations in which the prospects are understood by management. Technological tools are regularly used to reduce risk and increase the probability of success.

PetroShale relies on appropriate sources of funding to support the various stages of the Company's business strategy. There is no guarantee that external sources of financing will be available in the future, on favorable terms or at all. The various sources of funding include:

- Internally-generated cash flow from production;
- New equity, if available on favorable terms, may be utilized to fund acquisitions, to expand capital programs when appropriate and to repay any outstanding debt; and
- Debt, in the form of traditional oil and gas borrowing base bank facilities, and/or subordinated debt such as the Company's subordinated loan which typically has a higher cost than bank debt.

The Company is exposed to commodity price and market risk for our principal products of crude oil and natural gas. Commodity prices are influenced by a wide variety of factors, most of which are beyond PetroShale's control. To manage this risk, from time to time, the Company may enter into financial derivative contracts for hedging purposes. These derivative contracts may relate to crude oil and natural gas prices, as well as foreign exchange and interest rates. The Company may also, from time to time, enter into fixed physical contracts. The Company monitors the cost and associated benefit of these instruments and contracts as well as any debt levels and utilization rates on debt lines, and utilizes these derivatives and contracts when warranted. Although the Company's intent in entering into such derivative contracts is to manage its exposure to fluctuations in commodity prices, such contracts may limit the Company's ability to fully realize the benefits of higher market prices.

Risk of inflation subjects the Company to potential erosion of product netbacks, and returns from well drilling and completion activities. For example, increasing costs of oil and natural gas production equipment and services can inflate operating costs and/or drilling and well completion expenditures. In addition, increasing prices for undeveloped land can inflate costs of both asset and corporate acquisitions.

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a reasonable cost and produce them in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. The Company and the operators of its non-operated properties attempt to mitigate this risk by developing long-term relationships with suppliers and contractors and maintaining an appropriate inventory of production equipment.

The oil and natural gas industry has various environmental risks subject to regulation by various governmental bodies. Environmental legislation includes, but is not limited to, operational controls, site restoration and abandonment requirements and restrictions on emissions of various substances related to the production of oil and natural gas. The North Dakota Industrial Commission ("NDIC") has adopted rules requiring operators to have a gas capture plan for new wells and placing production restrictions to reduce gas flaring. Compliance with this legislation may require additional costs and a failure to comply may result in fines and penalties, and/or a requirement to shut-in production. This may also result in delays to commencement of production from oil wells where associated gas production may not yet be tied in to gathering and processing facilities. Additionally, an increase in demand for gas gathering infrastructure and supply of natural gas could increase related processing costs and decrease realized prices, negatively impacting realizations from production.

Demand for crude oil, natural gas liquids ("NGLs") and natural gas produced by the Company exists within Canada and the United States; however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are currently primarily affected by factors restricted to the North American market. Demand for natural gas liquids is influenced mainly by the demand for petrochemicals in North American and off-shore markets.

PetroShale mitigates these risks as follows:

- PetroShale and the operators of certain of our properties attempt to explore for and produce crude oil that is high quality (light, sweet), mitigating the Company's exposure to adverse quality differentials;
- Natural gas production will generally be connected to established pipeline infrastructure or other uses for the natural gas may be found;
- Sale arrangements will vary in term and pricing structure creating a diverse portfolio that minimizes risk of exposure to any one market; and
- Financial derivative instruments may be used where appropriate to manage commodity price volatility.

PetroShale drilled and completed its first operated well in the fourth quarter of 2016, and intends to drill and complete additional operated wells during the remainder of this year and going forward. Previously, the Company relied on third parties to operate production and drill wells on our land. Conducting operations will expose the Company to additional risks in terms of engaging service suppliers and drilling contractors, the normal oilfield risks of dangerous operations and the potential for discharge of hazardous substances into the environment, arranging for marketing of the Company's oil and natural gas production, as well as financing the costs of completing the well and recovering a share of those costs from our non-operating partners. The Company has and will continue to engage appropriate resources to ensure these risks are managed to the extent possible.

PetroShale owns leases from individual mineral owners (Fee Leases), the State of North Dakota acting by and through the Board of University and School Lands (State Leases), individual Indians with approval from the Secretary of the Interior of the Bureau of Indian Affairs (Allotted or BIA Leases), and the Bureau of Land Management (Federal Leases). PetroShale adheres to the National Environmental Policy Act in its operations and is under the regulatory authority of the North Dakota Industrial Commission, the Bureau of Indian Affairs (BIA), the Bureau of Land Management and the Department of the Interior's Office of Natural Resources Revenue. The Allotted leases are held in trust by the United States for the benefit of individual Indians and are subject to restrictions against alienation or encumbrance without approval of the Secretary of the Interior. All of the Company's Allotted Leases are located within the boundaries of the Fort Berthold Indian Reservation (FBIR) which makes the Company subject to unique regulations that are not applicable to lands outside the FBIR. The Company mitigates this risk by maintaining good relationships with the BIA and staying abreast of current regulations. PetroShale's ability to execute projects and realize the benefits therefrom is subject to factors beyond our control, including changes to regulations promulgated by any of the above entities.

PetroShale owns interests in certain oil and natural gas leases beneath the Missouri River in North Dakota. In late 2013, the North Dakota Supreme Court upheld that the State of North Dakota owns the mineral rights under the navigable portions of the Missouri River up to the delineated high water mark. PetroShale had purchased interests in certain leases which were negatively impacted by the decision, although not materially. There is ongoing litigation as to the proper delineation of the high water mark which could further impact PetroShale's interest in these leases, positively or negatively.

Like most companies of our size, PetroShale has a limited number of accounting and finance personnel, and therefore it is difficult to create strong segregation of duties which is normally a feature of a company's internal control structure. The Company mitigates this risk through management's performance of analytical review on operating and financial results.

Non-IFRS Measures

The reconciliation between funds flow from operations, as defined herein, and cash flow from operating activities, as defined by IFRS, is as follows:

	Three months ended June 30,		Six months ended June 30,	
(in thousands)	2017	2016	2017	2016
Cash flow from operating activities	$ 9,350	$ 1,076	$ 13,310	$ 3,893
Change in non-cash working capital	(4,799)	1,658	(729)	139
Funds flow from operations	$ 4,551	$ 2,734	$ 12,581	$ 4,032

The reconciliation between net loss and EBITDA, as defined herein, is as follows:

	Three months ended June 30,		Three months ended March 31,	
(in thousands)	2017	2016	2017	2016
Net loss	$ (847)	$ (2,947)	$ (757)	$ (6,427)
Add back:				
Depletion and depreciation expense	3,429	2,391	7,463	4,378
Finance expense	1,882	3,268	5,753	6,031
Foreign exchange gain	(71)	(140)	(71)	(520)
Share-based compensation expense	87	22	183	50
Unrealized gain on financial derivatives	-	-	(61)	-
EBITDA	$ 4,480	$ 2,594	$ 12,510	$ 3,512

Off Balance Sheet Arrangements

PetroShale is not involved with any contractual arrangement under which a non-consolidated entity may have an obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to a non-consolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. PetroShale has no obligation under financial instruments or a variable interest in a non-consolidated entity that provides financing, liquidity, market risk or credit risk support to the Company.

Additional Information

Additional information can be obtained by contacting the Company at PetroShale Inc., Suite 3900, 350-7th Avenue SW, Calgary, Alberta T2P 3N9 or by email at info@petroshaleinc.com. Additional information is also available on www.sedar.com or www.petroshaleinc.com.