PetroShale

Calgary • Denver

Management's Discussion & Analysis

As at September 30, 2018
and for the three and nine months ended September 30, 2018 and 2017

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 November 28, 2018. This MD&A reports on the consolidated financial position and the consolidated results of operations of PetroShale for the three and nine month periods ended September 30, 2018 and 2017 and should be read in conjunction with PetroShale's consolidated interim financial statements as at and for the three and nine month periods ended September 30, 2018 and the consolidated financial statements as at and for the year ended December 31, 2017. 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
Bopd	Barrels of oil per day
Boepd	Barrels of oil equivalent per day
Mboe	Thousand barrels of oil equivalent
Mcf	Thousand cubic feet
Mmboe	Million barrels of oil equivalent
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
PV10	Present value, reflecting a 10% discount rate

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 and Changes in Accounting Policies

The MD&A contains the terms "operating netback", "operating netback prior to hedging", "net debt" and "adjusted EBITDA" which are not defined by IFRS and therefore may not be comparable to performance measures presented by others. Operating netback represents revenue, plus or minus any realized gain or loss on financial derivatives less royalties, production taxes, operating costs and transportation expense. The operating netback is then divided by the working interest production volumes to derive the operating netback on a per Boe basis. Operating netback prior to hedging represents operating netback prior to any realized gain or loss on financial derivatives. Net debt represents total liabilities, excluding any decommissioning obligation and financial derivative liability, less current assets. Adjusted EBITDA represents cash flow from operating activities prior to changes in non-cash working capital. The Company believes that adjusted EBITDA provides useful information to the reader in that it measures the Company's ability to generate funds to service its debt and other obligations and to fund its operations, without the impact of changes in non-cash working capital which can vary based solely on timing of settlement of accounts receivable and accounts payable. Management believes that in addition to net income (loss) and cash flow from operating activities, operating netback and adjusted EBITDA are useful supplemental measures as they assist in the determination of the Company's operating performance, leverage and liquidity. Operating netback is commonly used by investors to assess performance of oil and gas properties and the possible impact of future commodity price changes on energy producers. Investors should be cautioned, however, that these measures should not be construed as an alternative to either net income (loss) or cash flow from operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

The reconciliation between adjusted EBITDA and cash flow from operating activities can be found later within this MD&A.

Please note the adoption of IFRS 15 effective January 1, 2018 with retrospective effect, which has an effect on revenue and operating expenses as previously presented, and results in the separate presentation of transportation expense on the statement of operations. This new accounting policy is described in Note 2 to the interim consolidated financial statements.

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 financing, production estimates, expected commodity mix and prices, expectations as to differentials relative to benchmark commodity prices received for our production, reserve estimates, future operating and transportation costs, expected royalty rates, anticipated timing and impact of new gas transportation and processing facilities in North Dakota, expected general and administrative expenses, expected interest rates, debt levels, cash 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 2018 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 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 and transportation 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; differentials between benchmark commodity prices and those received by the Company for its production in the field; 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

	Three months ended September 30,		Nine months ended September 30,	
(all $ amounts are presented in Canadian dollars)	2018	2017	2018	2017
FINANCIAL *(in thousands, except per share and share data)*				
Oil and natural gas revenue	$ 40,123	$ 7,292	$ 95,566	$ 32,939
Cash flow from operating activities	$ 20,112	$ 3,627	$ 49,702	$ 16,937
Net income (loss)	$ 10,449	$ (854)	$ 19,074	$ (1,611)
Per share - diluted	$ 0.06	$ (0.01)	$ 0.11	$ (0.01)
Adjusted EBITDA (1)	$ 22,018	$ 2,954	$ 53,253	$ 15,535
Capital expenditures	$ 90,045	$ 14,959	$ 167,606	$ 32,578
Net debt(1)			$ 150,281	$ 60,417
Common shares outstanding			190,789,972	157,097,767
Weighted average - basic	175,322,589	156,990,553	164,068,659	111,872,688
Weighted average - diluted	179,017,367	156,990,553	167,820,840	111,872,688
OPERATING				
Number of Days	92	92	273	273
Daily production(2)				
Crude oil (Bbls)	4,784	1,411	4,116	1,988
Natural gas (Mcf)	6,257	1,211	4,101	1,759
NGLs (Bbls)	971	281	700	274
Barrels of oil equivalent (Boe)	6,797	1,894	5,500	2,555
Average realized price				
Crude oil ($/Bbl)	$ 86.77	$ 53.76	$ 81.86	$ 57.95
Natural gas ($/Mcf)	$ 1.09	$ 1.38	$ 1.14	$ 1.92
NGLs ($/Bbl)	$ 14.63	$ 6.06	$ 12.00	$ 7.37
Netback per Boe ($) (1)				
Revenue	$ 64.16	$ 41.85	$ 63.64	$ 47.23
Royalties	$ (13.01)	$ (8.92)	$ (12.50)	$ (9.95)
Realized loss on derivatives	$ (3.75)	$ -	$ (3.63)	$ -
Operating costs	$ (3.48)	$ (5.79)	$ (3.71)	$ (6.21)
Production taxes	$ (4.82)	$ (3.16)	$ (4.91)	$ (3.56)
Transportation expense	$ (1.57)	$ (1.20)	$ (1.22)	$ (1.10)
Operating netback(1)	$ 37.53	$ 22.78	$ 37.67	$ 26.41
Operating netback prior to hedging(1)	$ 41.28	$ 22.78	$ 41.30	$ 26.41

(1) Non-IFRS measure - See pages 2-3 and the table s under "Non-IFRS Measure" at the end of this MDA for a reconciliation of adjusted EBITDA and net debt.

(2) 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.

RECENT SIGNIFICANT EVENTS

Oil and Gas Lease Development

The Company drilled four (3.3 net) operated wells in its Horse Camp field in South Berthold and the Primus field in our core Antelope area during the third quarter of 2018. The Company also participated in four (1.6 net) non-operated wells, which commenced production in July 2018. In the fourth quarter, the Company commenced completion activities on the two (1.8 net) Horse Camp wells we drilled in the third quarter and also commenced drilling operations on three (1.5 net) wells in another operated field in South Berthold.

Acquisition

In August 2018, the Company closed an acquisition of high quality assets in our South Berthold focus area (the "Acquisition"). The assets include approximately 1,980 net acres in three drilling units which the Company plans to operate and develop, along with approximately 550 Boepd of low decline production. Total consideration for the Acquisition was US$51.7 million in cash and was settled with proceeds from the Equity Financings discussed below and a draw on our senior loan facility.

Financing Activity

Concurrent with the Acquisition, the Company completed a $46.0 million "bought deal" equity financing through a syndicate of underwriters and a concurrent equity private placement for gross proceeds of $12.5 million (the "Equity Financings"). The Equity Financings initially closed on August 14, 2018 with the issuance of 31.6 million subscription receipts at $1.85 per subscription receipt, which were converted to an equivalent number of common shares on closing of the Acquisition on August 17, 2018. The aggregate net proceeds of the Equity Financings and a draw under the Company's senior credit facility of US$10.5 million, were used to close the Acquisition.

Upon the closing of the Acquisition, the borrowing capacity of the Company's senior credit facility was further increased to US$92.0 million. Following the senior lenders' semi-annual review of the Company's borrowing base in November, they agreed to further increase the borrowing base capacity of the facility to US$125 million, leaving the Company with approximately US$81 million of undrawn capacity as at November 28, 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 daily production volumes for the relevant periods.

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
Crude oil (Bbls per day)	4,784	1,411	4,116	1,988
Natural gas (Mcf per day)	6,257	1,211	4,101	1,759
NGLs (Bbls per day)	971	281	700	274
Total (Boe per day)	6,797	1,894	5,500	2,555
Liquids % of Production	85%	89%	88%	89%

Production was 7% higher than the second quarter 2018 average of 6,350 Boe per day and 259% higher than the third quarter of 2017. The large increase in production in the third quarter of 2018 over the third quarter of 2017 reflects a full three months of production from our four (3.7 net) operated wells which were put into production during the first quarter and the recommencement of production from our first operated well following a workover completed at the end of March. Production from these new wells are following a natural decline which was partially offset by the impact of four (1.6 net) non-operated wells placed on production in July 2018 and the addition of one and a half months of production from the new wells acquired in the Acquisition which closed in mid-August. Year over year, production is 115% higher as a result of each of the factors described above.

We are currently completing the two (1.8 net) Horse Camp wells we drilled in the third quarter and which we anticipate will be placed into production in December of 2018.

Pricing

Average benchmark prices	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Crude oil – WTI (US$ per Bbl)	$ 69.50	$ 48.17	$ 67.10	$ 49.39
Natural gas – HH (US$ per Mcf)	2.93	2.92	2.95	3.00
Exchange rate (US$ /CAD$)	1.307	1.253	1.287	1.307
Realized prices (CAD)				
Crude oil ($ per Bbl)	$ 86.77	$ 53.76	$ 81.86	$ 57.95
Natural gas ($ per Mcf)	1.09	1.38	1.14	1.92
NGLs ($ per Bbl)	14.63	6.06	12.00	7.37
Per Boe	$ 64.16	$ 41.85	$ 63.64	$ 47.23
Realized prices (USD)				
Crude oil ($ per Bbl)	$ 66.39	$ 42.91	$ 63.61	$ 45.27
Natural gas ($ per Mcf)	0.83	1.10	0.90	1.50
NGLs ($ per Bbl)	11.20	4.83	9.33	5.76
Per Boe	$ 49.09	$ 33.39	$ 49.45	$ 36.90

Realized oil prices in the three month and nine month periods ended September 30, 2018 improved significantly compared to the same periods in 2017 mainly due to higher WTI benchmark prices as well as improved differentials. Realized natural gas prices remain discounted to Henry Hub benchmark prices reflecting the high demand for gas capture pipeline and processing capacity in the area. The Company does not expect this differential to improve until new plant and gathering capacity is introduced, which is not anticipated until 2019. NGL average prices have increased relative to the comparable periods in 2017 reflecting an increase in oil prices.

The Company realizes a differential on its oil production relative to WTI. In the third quarter of 2018, that differential was US$3.11 per BbL on average, compared to US$5.26 per Bbl in the comparative period in 2017 and US$4.40 per Bbl in the second quarter of 2018. Subsequent to the end of the third quarter, a number of factors have resulted in a widening of the differential paid for Bakken oil production relative to WTI which, absent an offsetting change to WTI, will result in a reduction to realized prices from the third quarter.

The Company has several oil price derivative contracts in place for the remainder of the calendar year 2018. See "Business Conditions and Risks" later in this MD&A. The impact of these hedges was felt in the third quarter with a realized loss from financial derivatives of $3.75 per Boe as oil prices have increased significantly since these hedges were put in place in September of 2017.

Royalties

	Three months ended September 30		Nine months ended September 30,	
	2018	2017	2018	2017
Royalties (in thousands)	$ 8,143	$ 1,554	$ 18,766	$ 6,941
Royalties per Boe	$ 13.01	$ 8.92	$ 12.50	$ 9.95
Royalties as % of Revenue	20.3%	21.3%	19.6%	21.1%

Royalty expense as a percentage of revenues has decreased in the third quarter of 2018 relative to the comparative period in 2017 due to an increase in production from Company operated wells with a lower royalty interest compared to the Company's historical production. The royalties per Boe amount is higher for the three months ended September 30, 2018 due to the higher realized revenue per Boe, compared to the third quarter of 2017. Royalty expense is higher, on an absolute dollar basis, in the third quarter of 2018 compared to the same period in 2017, due to higher overall production and revenues.

Operating Costs, Production Taxes and Transportation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Operating costs	$ 2,178	$ 1,009	$ 5,567	$ 4,332
Production taxes	3,013	550	7,370	2,482
Transportation expense	979	209	1,837	759
Total (in thousands)	$ 6,170	$ 1,768	$ 14,774	$ 7,573
Operating costs per Boe	$ 3.48	$ 5.79	$ 3.71	$ 6.21
Production taxes per Boe	4.82	3.16	4.91	3.56
Transportation expense per Boe	1.57	1.20	1.22	1.10
Total per Boe	$ 9.87	$ 10.15	$ 9.84	$ 10.87

Operating costs

Operating costs per Boe for the three months ended September 30, 2018 were lower than the comparative period in 2017 due to a portion of these costs being fixed per well and averaged over high initial production from our new operated wells.

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 September 30, 2018 reflect the impact of higher realized prices and are consistent period over period as a percentage of revenue. Management anticipates production taxes in the future to continue to reflect the oil composition of the Company's production.

Transportation expense

Transportation expense reflects costs associated with a certain portion of our oil production transported by pipeline. These costs are higher in the third quarter of 2018 reflecting a higher portion of our production being tied into pipelines. Previously, the majority of our operated oil production was sold at the wellhead and transportation expense was reflected in the net price received from the purchaser.

Operating Netback

	Three months ended September 30,		Nine Months Ended September 30,	
($ per Boe)	**2018**	**2017**	**2018**	**2017**
Revenue	$ 64.16	$ 41.85	$ 63.64	$ 47.23
Royalties	(13.01)	(8.92)	(12.50)	(9.95)
Realized loss on derivatives	(3.75)	-	(3.63)	-
Operating costs	(3.48)	(5.79)	(3.71)	(6.21)
Production taxes	(4.82)	(3.16)	(4.91)	(3.56)
Transportation expense	(1.57)	(1.20)	(1.22)	(1.10)
Operating netback	$ 37.53	$ 22.78	$ 37.67	$ 26.41
Operating netback prior to hedging	$ 41.28	$ 22.78	$ 41.30	$ 26.41

Our operating netback increased for the three and nine months ended September 30, 2018 compared to the corresponding prior periods due to the improved commodity price environment and lower oil price differential slightly offset by the realized hedge losses in 2018, and higher production taxes.

General and Administrative Expense

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
Gross general and administrative expense	$ 1,696	$ 1,120	$ 4,346	$ 3,129
Capitalization of internal development costs	(252)	(101)	(983)	(163)
Third party recoveries	-	(3)	(43)	(5)
Net general and administrative expense (in thousands)	$ 1,444	$ 1,016	$ 3,320	$ 2,961

Gross general and administrative expense ("G&A") increased during the three months ended September 30, 2018 compared to the same period in the prior year due to higher legal and other costs associated with recent acquisitions and the addition of senior personnel. Capitalization of G&A expenses was lower in the third quarter compared to the first quarter due to a reduction in operated capital activities, but was higher than the comparative period of 2017 due to limited capital activities in the comparative period.

Depletion and Depreciation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Depletion and depreciation expense (in thousands)	$ 9,855	$ 2,333	$ 23,195	$ 9,796
Depletion and depreciation per Boe	$ 15.76	$ 13.39	$ 15.45	$ 14.04

Depletion and depreciation expense is calculated using proven and probable reserves. Depletion and depreciation expense increased during the periods ended September 30, 2018 compared to the prior comparable periods, due to higher production volumes. The depletion and depreciation expense per Boe is higher year over year due to a higher finding and development cost per Boe reflected in the December 31, 2017 reserves evaluation.

Finance Expense

Finance expense in the comparable 2017 period reflects interest on the Company's senior and subordinated credit facilities, including the amortization of certain loan origination and other fees. Finance expense for the three months ended September 30, 2018 reflects costs primarily associated with the Company's senior credit facility and the preferred shares, which were issued in January 2018 and are treated as a financial liability for accounting purposes. Finance expense was higher year over year reflecting higher debt levels in 2018 following the Company's significant drilling and acquisition programs during the fourth quarter of 2017 and to date in 2018. Although debt levels are higher in 2018 on an absolute basis, they are lower relative to cash flow from operating activities.

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 first nine months of 2018, management determined that no impairment indicators existed. The increase in WTI prices in 2018, and overall increases in the Company's reserve volumes as reflected in our December 31, 2017 reserve report, support management's determination.

Share-based Compensation

Share-based compensation expense reflects the value ascribed to equity-based compensation 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 such equity awards will vest. The expense for the three months ended September 30, 2018 is net of stock-based compensation costs of $166,000 capitalized to property, plant and equipment (2017 - $0) and the expense for the nine months ended September 30, 2018 is net of $243,000 capitalized to property, plant and equipment (2017 - $7,000). The increase in expense year over year is due to the grant of 2,625,000 restricted bonus awards in November 2017 and the grant of 235,000 restricted bonus awards in 2018.

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 currency translation gain of $3.6 million for the nine months ended September 30, 2018, due to the weakening of the Canadian dollar relative to the US dollar from December 31, 2017 (US dollar / Canadian dollar 1.26) to September 30, 2018 (US dollar / Canadian dollar 1.30) and the fact that the Company's US dollar-denominated assets exceed its liabilities.

Share Capital

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Weighted average common shares outstanding:				
Basic	175,322,589	156,990,553	164,068,659	111,872,688
Diluted	179,017,367	156,990,553	167,820,840	111,872,688
Outstanding securities:				
Common shares, voting and non-voting			190,789,972	157,097,767
Preferred shares, convertible			75,000	-
Restricted bonus awards			2,751,667	-
Stock options			1,518,264	1,718,264
Warrants			-	2,000,000

As at November 28, 2018, we had 190,789,972 common shares, 1,518,264 stock options and 2,751,667 restricted bonus awards outstanding. The increase in common shares outstanding in 2018 primarily reflects the Equity Financings completed in August. In March 2018, the holders of the warrants exercised their right to acquire 2 million common shares for net proceeds to the Company of $1.5 million. The preferred shares are convertible into 39,308,176 common shares at the election of the holder. As of September 30, 2018, all of the Company's common shares are voting.

The following reflects the outstanding stock options as at September 30, 2018:

Stock Options

Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Number of Outstanding Options	Number of Options Exercisable
$0.70	1.12	1,518,264	1,388,263

The restricted bonus awards expire before the third year from the date of grant and vest in equal annual tranches following the date of issuance.

Capital Expenditures

The following table represents capital expenditures for the nine months ended September 30, 2018:

(in thousands)	
Capital expenditures	
Acquisitions	$ 93,520
Drilling and completion	74,086
Total capital expenditures	$ 167,606

During the nine months ended September 30, 2018, the Company participated in 77 gross (10.4 net) wells, which were in various stages of completion.

The Company has no commitments to make additional capital expenditures following the end of the period, with the exception of approximately US$5 million related to operated and non-operated wells which were partially completed at the end of the quarter. We estimate future development costs of US$367 million related to our proven undeveloped and probable reserves as at September 30, 2018.

Liquidity and Capital Resources

Capital expenditures of $167.6 million for acquisitions and drilling and completion activities for the nine months ended September 30, 2018 were financed indirectly through proceeds from sale of common shares, from draws on the Company's senior loan facility, issuance of preferred shares and operating cash flows.

The Company is dependent on cash on hand, operating 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 the outlook for future cash flow be impacted in a negative way, the Company is capable of reducing its capital spending levels by not consenting to participate in additional drilling proposed by operators of its non-operated properties or by reducing its drilling and completion activity on its operated properties. 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 funds flow from operations and available capacity under our senior credit facility.

In August 2018, the Company closed two subscription receipt offerings, a public offering underwritten by a syndicate of dealers for $46.0 million and a private placement of $12.5 million (the "Equity Financings"). $10.0 million of the private placement was provided by our Executive Chairman and First Reserve, the holder of our outstanding preferred shares. The subscription receipts issued on closing of the Equity Financings were exchanged for common shares of the Company on closing of the Acquisition. The net proceeds from the Equity Financings totaled approximately $55 million and, along with a draw on the Company's senior credit facility of US$10.5 million, was used to close the Acquisition. As of the date of this MD&A, the Company is drawn approximately US$44 million on its senior credit facility leaving US$48 million of undrawn capacity, as described below.

The Company maintains a senior revolving credit facility which is referred to as the senior loan in the statement of financial position. The capacity of this facility is US$92.0 million as at September 30, 2018. The maturity date is June 30, 2019, at which point, the facility can be extended at the option of the lenders, or if not extended, the facility would be converted to a non-revolving facility with a term maturing on June 30, 2020. The amount of the facility is subject to a borrowing base test performed on a periodic basis and at least twice annually by the lenders, based primarily on producing oil and natural gas reserves and using commodity prices estimated by the lender as well as other factors. A decrease in the borrowing base determined by the senior lenders in the future could result in a reduction to the credit facility, which may require a repayment to the lenders. Following their semi-annual review of the Company's borrowing base in November, the senior lenders agreed to further increase the borrowing base capacity of the facility to US$125 million ($162.5 million). As at November 28, 2018, the facility is drawn approximately US$44 million ($57 million). The undrawn capacity of the senior credit facility is approximately US$81 million which will facilitate the Company's execution of its drilling and completion program.

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 2.5 to 1 on a rolling four-quarter basis; and (ii) a requirement that the ratio of the senior loan amount to Bank 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 (relevant in 2017) and other non-cash amortization expense included in finance expense on the company's statement of operations. Consolidated cash flow is defined as consolidated net income (loss) 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. Bank EBITDA is defined as consolidated cash flow under the senior loan facility without adjustment for any equity proceeds. The consolidated cash flow to interest expense ratio at September 30, 2018 was 23 to 1, and the senior loan to Bank EBITDA ratio was 0.9 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.

Previously the Company had a secured, subordinated revolving credit facility. The facility was intended to allow the Company to close acquisitions and/or fund drilling and well completion capital expenditures. The credit facility bore interest at a rate of 12% per annum and included a 2.5% origination fee. The credit facility was 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$24.5 million, as at December 31, 2017, of the then-available capacity of US$80.0 million. The subordinated loan facility was settled with the proceeds of the preferred share financing completed in January 2018 (described below), and as a condition of that financing, the subordinated loan facility was terminated.

The Company closed a common share 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.

On January 25, 2018, the Company closed a preferred equity financing with a private investor (the "Investor") for gross proceeds of US$75 million. The preferred shares were issued by the Company's US subsidiary and are convertible, at the Investor's option, to common shares of the Company at a fixed price of $2.40 per share, subject to certain conditions. The preferred shares have a term of five years (subject to extension for an additional year at the election of the Investor) and entitle the Investor to a cumulative annual dividend of 9% per annum (except that no dividends shall be payable for the extension year, if any), payable quarterly. As part of the financing, the Investor also acquired voting preferred shares of the Company which entitle the Investor to the "as-exchanged" voting rights of the subsidiary preferred shares.

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 two recent equity offerings 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.

The following reflect the contractual maturities of the Company's debt obligations and anticipated timing of settlements of its other financial liabilities as at September 30, 2018, including estimated interest payments:

(in thousands)	Contractual Cash Flow	Less than 1 Year	1-2 Years	3-5 Years	Thereafter
Accounts payable and accrued liabilities	$ 31,638	$ 31,638	$ -	$ -	$ -
Senior loan [1]	$ 66,330	2,710	63,620	-	-
Preferred share obligation[2]	135,829	8,802	8,802	118,225	-
Total	$ 233,797	$ 43,150	$72,422	$ 118,225	$ -

[1]Includes future interest expense at the rate of 4.4% being the rate applicable at September 30, 2018 to the current maturity date of June 30, 2020.

[2]The amount differs from that presented on the statement of financial position due, in part, to the unamortized portion of issuance costs (which are offset against the loan principal on the statement of financial position), the preferred share equity component (which is presented separately under Shareholders' Equity) and finance cost at the coupon rate of 9.0% per annum. The table reflects the full interest obligation to the maturity date of January 25, 2023. These preferred shares may be converted to common shares at the option of the investor.

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.

During 2017, the Company had a secured, subordinated, revolving credit facility which was available to be drawn in US dollars and which had a capacity of US$80.0 million and a maturity date of January 15, 2019. The credit facility was provided by two significant shareholders of the Company, one of whom is the Executive Chairman of our Board of Directors. This facility was repaid and terminated following completion of the preferred share financing in January 2018. 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 at the time, 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 entitled 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 statement of financial position. These warrants were all exercised in March 2018 for net proceeds to the Company of $1.5 million.

Summary of Quarterly Results

Three month period ended (in thousands):	9/30/2018	6/30/2018	3/31/2018	12/31/2017	9/30/2017	6/30/2017	3/31/2017	12/31/2016
Oil and natural gas sales, net of royalties	$ 31,980	$ 29,246	$ 15,574	$ 8,171	$ 5,738	$ 8,357	$ 11,903	$ 5,951
Cash flow from operations(1)	20,112	21,734	7,856	2,333	3,627	9,350	3,960	2,021
Net income (loss)	10,449	6,274	2,351	(1,482)	(854)	(847)	90	(3,048)
Net income (loss) per share - basic and diluted	$ 0.06	$ 0.04	$ 0.01	$ (0.01)	$ (0.01)	$ (0.01)	$ 0.00	$ (0.09)

(1)See Note 2 to the consolidated financial statements for the year ended December 31, 2017 which describes the impact of a change in classification of finance expense in the statement of cash flows.

Factors that influenced quarterly variations

Quarter over quarter fluctuations are attributable to the items discussed below. Revenue, cash flow from operations and net income saw significant growth in the second and third quarters of 2018 compared to prior periods due to increased production volumes resulting from the Company's operated drilling program. The first quarter of 2018 also saw significantly increased production volumes and improved oil pricing which resulted in net income, higher revenue and improved cash flow from operations. Revenues in the fourth quarter of 2017 increased compared to the third quarter due to higher production volumes from new wells and a stronger commodity price environment. Despite the increase in revenues in the fourth quarter of 2017, an unrealized loss on financial derivatives resulted in a larger net loss in this period than the third quarter of 2017. Stabilizing production on new wells and lower WTI prices resulted in the decreased sales revenue in the three months ended September 30, 2017 and the three months ended June 30, 2017. Cash flow from operations in the third quarter of 2017 decreased relative to the second quarter of 2017 due to a large reduction in non-cash working capital in the second quarter of 2017. The first quarter of 2017 saw increased production volumes which resulted in increased sales which, along with lower operating costs, produced positive net income for that quarter 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.

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 December 31, 2016, June 30 and December 31, 2017, and September 30, 2018 where the impact of changes in non-cash working capital offset the impact of changes in operating results.

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 become 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, 2017.

Decommissioning obligation

The calculation of the decommissioning obligation in the statement 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 and share awards. These estimates can impact net income (loss) and contributed surplus.

Preferred Shares

The preferred shares are a compound financial instrument given they have both debt and equity features. This necessitated an estimation of the fair value of the debt component of the preferred shares, requiring judgement in determining equivalent terms of a debt instrument without an equity conversion feature. These estimates can impact net income (loss) and the amounts reflected as preferred share obligation and preferred share equity component on the statement of financial position.

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" was adopted effective January 1, 2018. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and by contractual cash flow characteristics.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" model. The new impairment model applies to financial assets measured at amortized cost, and contract assets and debt investments at FVOCI. Under IFRS 9, credit losses are recognized earlier than under IAS 39. There was no impact on the Company's financial statements on adoption of this pronouncement.

Cash and cash equivalents and trade and other receivables continue to be measured at amortized cost and are now classified as "amortized cost". The Company's financial liabilities continue to be measured at amortized cost. The Company has not designated any financial instruments as FVOCI or FVTPL, nor does the Company use hedge accounting for any of its commodity financial derivatives.

IFRS 15 – "Revenue from Contracts with Customers" was issued in May 2014 to replace IAS 11 – "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. Effective January 1, 2018, the Company adopted IFRS 15 using the retrospective effect method. The new standard did not have a material impact on net income in the statement of operations. However, the Company has provided enhanced disclosures related to its Revenue which are reflected in Note 10 to the consolidated interim financial statements.

The Company's revenue recognition accounting policy, as revised with the adoption of IFRS 15, is as follows:

Revenues associated with the production and sale of petroleum products owned by the Company are recognized at the point in which control of the products is transferred to the buyer, which may be when the production enters that party's pipeline or processing facility. Processing or transportation fees costs associated with petroleum production are netted against the related revenue if they are incurred following the transfer of control to the entity which has purchased the commodity. If transportation or processing costs are incurred prior to the sale of the relevant commodity, such costs are reflected separately as an expense in the statement of operations.

In addition, the Company is required to evaluate its arrangements with its joint venture partners to determine if the Company acts as the principal or as an agent in respect of the sale of the partner's interest in production. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the products, having the ability to establish prices or assuming inventory risk. In the Company's case, it is acting in the capacity of an agent rather than as a principal in commodity sales transactions on its operated properties, and the revenue is recognized on a net basis.

IFRS 16 – "Leases" is a new standard which introduces a single lessee accounting model with required recognition of assets and liabilities for most leases. It 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 is not expected 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, 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. On our non-operated 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 operations;
- New equity, if available on acceptable 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 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. In addition, the Company is exposed to fluctuations in the differentials between market price benchmarks and what is received in our geographic area of operation for our production. To manage this risk, 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.

To reduce the anticipated impact of future volatility in commodity prices, the Company has entered into the following oil commodity price hedges.

Term	Type	Volumes	Price (per Bbl $US)	Reference
Oct 1, 2018 to December 31, 2018	Collar	500 Bopd	$45.00 - $55.70	WTI
Oct 1, 2018 to December 31, 2018	Collar	500 Bopd	$45.00 - $57.00	WTI
Oct 1, 2018 to December 31, 2018	Collar	500 Bopd	$47.00 - $56.75	WTI

Risk of cost 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.

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; and
- Financial derivative instruments may be used where appropriate to manage commodity price volatility.

The Company is exposed to operational 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 wells 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 native owners 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 native owners 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 material to PetroShale in aggregate. 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. Management mitigates this risk through performance of analytical review on operating and financial results.

Non-IFRS Measures

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

(in thousands)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Cash flow from operating activities	$ 20,112	$ 3,627	$ 49,702	$ 16,937
Change in non-cash working capital	1,906	(673)	3,551	(1,402)
Adjusted EBITDA	$ 22,018	$ 2,954	$ 53,253	$ 15,535

The reconciliation of net debt as defined herein is as follows:

(in thousands)	September 30, 2018	September 30, 2017
Total liabilities	$ 185,255	$ 69,922
Decommissioning obligation	(4,685)	(2,070)
Financial derivative liability	(2,966)	(181)
Current assets	(27,323)	(7,254)
Net debt	$ 150,281	$ 60,417

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 3230, 421-7th Avenue SW, Calgary, Alberta T2P 4K9 or by email at info@petroshaleinc.com. Additional information is also available on www.sedar.com or www.petroshaleinc.com.