PetroShale

Calgary • Denver

Third Quarter Report

As at September 30, 2019
and for the three and nine months ended September 30, 2019 and 2018

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(all $ amounts are presented in Canadian dollars)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
FINANCIAL *(in thousands, except per share and share data)*				
Petroleum and natural gas revenue	$ 52,887	$ 40,123	$ 104,689	$ 95,566
Cash flow from operating activities	$ 32,275	$ 20,112	$ 50,859	$ 49,702
Net income	$ 4,982	$ 10,449	$ 5,719	$ 19,074
Per share - diluted	$ 0.03	$ 0.06	$ 0.03	$ 0.11
Adjusted EBITDA [1]	$ 29,996	$ 22,018	$ 55,921	$ 53,253
Capital expenditures	$ 63,883	$ 89,795	$ 172,104	$ 167,606
Net debt[1]			$ 301,865	$ 150,281
Common shares outstanding			192,170,243	190,789,972
Weighted average - basic	192,168,550	175,322,589	192,014,140	164,068,659
Weighted average - diluted	197,273,567	179,017,367	197,191,551	167,820,840
OPERATING				
Number of Days	92	92	273	273
Daily production[2]				
Crude oil (Bbls)	8,427	4,784	5,504	4,116
Natural gas (Mcf)	8,974	6,257	6,127	4,101
NGLs (Bbls)	1,544	971	979	700
Barrels of oil equivalent (Boe)	11,467	6,797	7,504	5,500
Average realized price				
Crude oil ($/Bbl)	$ 69.90	$ 86.77	$ 70.43	$ 81.86
Natural gas ($/Mcf)	$ 1.93	$ 3.09	$ 2.49	$ 3.09
NGLs ($/Bbl)	$ 4.82	$ 29.19	$ 9.84	$ 25.24
Netback per Boe ($) [1]				
Revenue	$ 50.13	$ 64.16	$ 51.10	$ 63.64
Royalties	$ (10.08)	$ (13.01)	$ (10.15)	$ (12.50)
Realized loss on derivatives	$ -	$ (3.75)	$ -	$ (3.63)
Lease operating costs	$ (2.78)	$ (2.88)	$ (4.38)	$ (2.88)
Workover expense	$ (1.22)	$ (0.60)	$ (1.31)	$ (0.83)
Production taxes	$ (4.09)	$ (4.82)	$ (4.05)	$ (4.91)
Transportation expense	$ (2.55)	$ (1.57)	$ (2.30)	$ (1.22)
Operating netback[1]	$ 29.41	$ 37.53	$ 28.91	$ 37.67
Operating netback prior to hedging[1]	$ 29.41	$ 41.28	$ 28.91	$ 41.30

(1) Non-IFRS measure - See pages 2-3 and the tables under "Non-IFRS Measures" at the end of this MD&A for a reconcilliation 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 MD&A as we feel they are easily understood by users and consistent with disclosure of our peers.

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 19, 2019. 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, 2019 and 2018 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, 2019 and the consolidated financial statements for the year ended December 31, 2018. 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 decommissioning obligation, lease liabilities and any 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, and the calculation of net debt, can be found later within this MD&A.

Please note the Company adopted IFRS 16 effective January 1, 2019 with no retrospective effect, which provides a single recognition and measurement model for lessees to recognize assets and liabilities for contracts that are, or contain, a lease. This new accounting policy is described in Note 2 to the consolidated interim financial statements and in "New and Future Accounting Pronouncements" later in this MD&A.

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 year ended December 31, 2019 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, unforeseen challenges or circumstances in drilling, equipping and completing wells leading to higher capital costs than anticipated, 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, unfavorable weather, 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.

MANAGEMENT'S DISCUSSION & ANALYSIS

DESCRIPTION OF BUSINESS

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

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 interim 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,	
	2019	2018	2019	2018
Crude oil (Bbls per day)	8,427	4,784	5,504	4,116
Natural gas (Mcf per day)	8,974	6,257	6,127	4,101
NGLs (Bbls per day)	1,544	971	979	700
Total (Boe per day)	11,467	6,797	7,504	5,500
Liquids % of Production	87%	85%	86%	88%

During the third quarter of 2019, production of 11,467 Boe per day was 93% higher than the second quarter of 2019 average of 5,940 Boe per day due to 14 gross (5.5 net) wells brought online in the third quarter of 2019. Production of 7,504 Boe per day for the nine months ended September 30, 2019 was 36% higher than the 5,500 Boe per day in the comparable period in 2018, as a result of new wells that were brought online during 2019 , slightly offset by the natural decline on the wells that commenced production in 2018. Liquids as a percentage of total production remained consistent during the periods ended September 30, 2019. NGL yields from associated natural gas production averaged 172 bbls/mmcf in the third quarter relative to 155 bbls/mmcf in the comparative period of 2018, consistent with 160 bbls/mmcf and 171 bbls/mmcf in the nine month periods ended September 30, 2019 and 2018, respectively.

Pricing

Average benchmark prices	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Crude oil – WTI (US$ per Bbl)	$ 56.43	$ 69.50	$ 57.05	$ 67.10
Natural gas – HH (US$ per Mcf)	2.38	2.93	2.62	2.95
Exchange rate (US$ /CAD$)	1.32	1.31	1.32	1.29
Realized prices (CAD)[1]				
Crude oil ($ per Bbl)	$ 69.90	$ 86.77	$ 70.43	$ 81.86
Natural gas ($ per Mcf)	1.93	3.09	2.49	3.09
NGLs ($ per Bbl)	4.82	29.19	9.84	25.24
Realized prices (USD)[1]				
Crude oil ($ per Bbl)	$ 52.88	$ 66.39	$ 53.28	$ 63.61
Natural gas ($ per Mcf)	1.46	2.37	1.88	2.37
NGLs ($ per Bbl)	$ 3.65	$ 22.38	$ 7.40	$ 19.30

[1] Excluding transportation and processing costs

The Company realizes a differential on its oil prices relative to WTI, on its gas prices relative to Henry Hub and on its NGL prices relative to Conway.

Realized oil prices for the three months ended September 30, 2019 decreased compared to the same period in 2018 due to weaker WTI prices. In the third quarter of 2019, WTI decreased US$13.07 relative to the same period in 2018 while the oil differential widened slightly to US$3.55 per Bbl on average, compared to US$3.11 per Bbl in the comparative period in 2018.

Henry Hub natural gas prices were lower in the third quarter of 2019 compared to the comparable period in 2018. Realized natural gas prices in the Bakken remain discounted to Henry Hub benchmark prices reflecting the shortage of takeaway and processing capacity in the area. The Company does not expect this differential to improve until new plant and gathering capacity is introduced. An additional 445 mmcf/day of natural gas transportation and processing capacity is expected near the end of 2019. NGL average prices declined significantly in the third quarter of 2019 relative to the comparable period in 2018 reflecting a decrease in benchmark prices at Conway due to oversupply in the market and the impact of transportation and marketing challenges associated with certain natural gas liquids in the US, particularly in the Williston basin.

Revenue

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Petroleum and natural gas	$ 52,887	$ 40,123	$ 104,689	$ 95,566

Revenues in the three and nine months ended September 30, 2019 increased 32% and 10%, respectively, compared to the corresponding 2018 periods. The increases are primarily due to increased production volumes from drilling activities, offset by lower realized commodity prices in 2019. Natural gas and natural gas liquids revenue are nominal in these periods. See further commentary above under “Pricing”.

Royalties

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Royalties (in thousands)	$ 10,638	$ 8,143	$ 20,791	$ 18,766
Royalties per Boe	$ 10.08	$ 13.01	$ 10.15	$ 12.50
Royalties as % of Revenue	20.1%	20.3%	19.9%	19.6%

Royalty expense as a percentage of revenues remained consistent with the comparative periods. Royalty expense is higher on an absolute dollar basis for the three and nine month periods ended September 30, 2019 compared to the same periods in 2018 due to higher overall production and revenues. The royalties per Boe amount is lower for the three and nine months ended September 30, 2019 as a result of lower realized oil, gas and NGL revenue per Boe compared to the same periods in 2018.

Operating Costs, Production Taxes and Transportation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Lease operating costs	$ 2,932	$ 1,802	$ 8,964	$ 4,317
Workover expense	1,288	376	2,685	1,250
Production taxes	4,314	3,013	8,291	7,370
Transportation expense	2,686	979	4,705	1,837
Total (in thousands)	$ 11,220	$ 6,170	$ 24,645	$ 14,774
Lease operating costs per Boe	$ 2.78	$ 2.88	$ 4.38	$ 2.88
Workover expense per Boe	1.22	0.60	1.31	0.83
Production taxes per Boe	4.09	4.82	4.05	4.91
Transportation expense per Boe	2.55	1.57	2.30	1.22

Lease operating costs

Operating costs per Boe for the three months ended September 30, 2019 were lower than the comparative period in 2018 due to substantially higher production in the third quarter of 2019. Operating costs per Boe for the nine months ended September 30, 2019 were higher than the comparative period of 2018 due to the impact of mature production from the acquisition that closed in the third quarter of 2018 and from higher fixed costs experienced in the first half of 2019 resulting from shutting in certain wells during that period for artificial lift and frac protect. Absolute lease operating costs were higher in 2019 due to an increased well count.

Workover expense

Workover expense per Boe for the three and nine months ended September 30, 2019 were higher than the comparative periods in 2018 due to increased workover activity on certain operated and non-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 and nine months ended September 30, 2019 reflect the impact of lower realized oil prices and

are consistent period over period as a percentage of revenue, net of royalties. 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 three and nine months ended September 30, 2019 reflecting a higher portion of our production being tied into pipelines and overall higher oil volumes. 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 resulting in lower wellhead pricing.

Operating Netback

	Three months ended September 30,		Nine months ended September 30,	
($ per Boe)	**2019**	**2018**	**2019**	**2018**
Revenue	$ 50.13	$ 64.16	$ 51.10	$ 63.64
Royalties	(10.08)	(13.01)	(10.15)	(12.50)
Realized loss on derivatives	-	(3.75)	-	(3.63)
Lease operating costs	(2.78)	(2.88)	(4.38)	(2.88)
Workover expense	(1.22)	(0.60)	(1.31)	(0.83)
Production taxes	(4.09)	(4.82)	(4.05)	(4.91)
Transportation expense	(2.55)	(1.57)	(2.30)	(1.22)
Operating netback	$ 29.41	$ 37.53	$ 28.91	$ 37.67
Operating netback prior to hedging	$ 29.41	$ 41.28	$ 28.91	$ 41.30

Operating netback decreased for the three and nine months ended September 30, 2019 compared to the corresponding prior period due to a decline in global oil prices and higher operating and transportation costs per Boe. The operating netback in the third quarter of 2019 declined relative to $32.22 in the second quarter of 2019, reflecting lower realized oil pricing quarter over quarter.

General and Administrative Expense

	Three months ended September 30,		Nine months ended September 30,	
	2019	**2018**	**2019**	**2018**
Gross general and administrative expense	$ 1,604	$ 1,696	$ 4,869	$ 4,346
Capitalization of internal development costs	(266)	(252)	(803)	(983)
Third party recoveries	(305)	-	(734)	(43)
Net general and administrative expense (in thousands)	$ 1,033	$ 1,444	$ 3,332	$ 3,320
General and administative expense per Boe	$ 0.98	$ 2.31	$ 1.63	$ 2.21

Gross general and administrative expense ("G&A") during the three month period ended September 30, 2019 was consistent with the comparable period but increased during the nine month period ended September 30, 2019 compared to the corresponding periods of 2018 due to the addition of senior personnel. G&A per Boe declined due to the significant increase in production in the third quarter of 2019.

Depletion and Depreciation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Depletion and depreciation expense (in thousands)	$ 16,260	$ 9,855	$ 31,172	$ 23,195
Depletion and depreciation expense per Boe	$ 15.41	$ 15.76	$ 15.22	$ 15.45

Depletion and depreciation expense is calculated using proven and probable reserves. Depletion and depreciation expense increased during the three and nine months ended September 30, 2019 compared to the prior comparable periods, due to higher production volumes. The per Boe expense is consistent year over year. The calculation of depletion and depreciation expense for the quarter ended September 30, 2019 includes estimated future development costs of US$335 million (September 30, 2018 – US$367 million) related to our proven undeveloped and probable reserves as at September 30, 2019.

Finance Expense

Finance expense for the three and nine months ended September 30, 2019 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 senior debt levels in 2019 following the Company's significant drilling and acquisition programs during calendar years 2018 and 2019.

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 September 30, 2019, management determined that no impairment indicators existed. The stabilization in WTI prices in 2019, the overall increases in the Company's reserve volumes as well as values as reflected in our December 31, 2018 reserve report and the recent increase in our borrowing capacity under our senior credit facility support management's determination.

Deferred Tax

The Company recorded a deferred income tax expense of $3,525,000 for the three months ended September 30, 2019 (nil for the prior year comparative period) as the Company recognized a deferred tax liability during 2019 following several periods of increasing net income for accounting purposes.

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, 2019 of $427,000 is net of stock-based compensation costs of $111,000 capitalized to property, plant and equipment compared to $377,000 net of $166,000 capitalized to property, plant and equipment for the comparative prior year period. The increase in expense in the third quarter of 2019 over the comparative period is

due to the grant of additional restricted bonus awards and performance bonus awards in July 2019.

Foreign Currency Gain and Translation Adjustment

The Company's consolidated interim 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 a currency translation adjustment in other comprehensive income. The Company experienced a currency translation gain of $2.1 million for the three months ended September 30, 2019 (2018 – loss of $1.8 million), due to the weakening of the Canadian dollar relative to the US dollar from June 30, 2019 (US dollar / Canadian dollar 1.31) to September 30, 2019 (US dollar / Canadian dollar 1.32) 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,	
	2019	2018	2019	2018
Weighted average common shares outstanding:				
Basic	192,168,550	175,322,589	192,014,140	164,068,659
Diluted	197,273,567	179,017,367	197,191,551	167,820,840
Outstanding securities:				
Common shares, voting and non-voting			192,170,243	190,789,972
Preferred shares, convertible			75,000	75,000
Stock options			550,000	1,518,264
Restricted bonus awards			4,012,968	2,751,667
Performance bonus awards			1,090,200	-

As at November 19, 2019, we had 192,170,243 common shares, 550,000 stock options, 4,012,968 restricted bonus awards and 1,090,200 performance awards outstanding. The increase in common shares outstanding relative to 2018 primarily reflects restricted bonus awards that vested in April 2019 and were settled with common shares issued from treasury. The increase in restricted bonus awards and performance bonus awards reflects employee long term incentive (LTI) share grants in July 2019. The preferred shares are convertible into 39,308,176 common shares at the election of the holder. As of September 30, 2019, all of the Company's outstanding common shares are voting.

Dilutive Equity Components

The following reflects the outstanding stock options as at September 30, 2019:

Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Number of Outstanding Options	Number of Options Exercisable
$0.70	1.81	550,000	550,000

The Company has granted restricted share bonus awards and performance share bonus awards (collectively,"awards") to certain directors, officers and employees. These awards expire before the end of the third year from the date of grant and vest annually in three tranches following the date of issuance. Performance share bonus awards are also subject to performance vesting terms which result in a multiplier of between 0 and 2 times applied to the number originally granted, based on performance relative to certain measures established by the Company's Board of Directors. The awards may be settled by the Company, in its sole discretion, in cash and/or common shares of the Company.

Capital Expenditures

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Drilling and completion	$ 63,380	$ 40,043	$ 168,349	$ 93,520
Acquisitions	484	49,752	3,667	74,086
Other	19	-	88	-
Total capital expenditures (in thousands)	$ 63,883	$ 89,795	$ 172,104	$ 167,606

During the three months ended September 30, 2019, the Company participated in 34 gross (4.7 net) wells, which were in various stages of completion as at September 30.

The Company has commitments to make additional capital expenditures following the end of the third quarter of approximately US$48 million related to operated and non-operated wells which were partially completed at the end of the quarter.

Liquidity and Capital Resources

Capital expenditures for acquisitions and drilling and completion activities for the three and nine months ended September 30, 2019 were financed from draws on the Company's senior loan facility, operating cash flows and working capital.

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 managing its cash flows by not consenting to participate in additional drilling proposed by operators of its non-operated properties, by reducing its drilling and completion activity on its operated properties and by entering into commodity price contracts. 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. The Company experienced an increase in operating cash flows in the third quarter of 2019 following a significant increase in production and expects to be able to maintain existing production levels within operating cash flows provided WTI prices do not decline significantly. 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.

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 was US$140.0 million as at September 30, 2019. The maturity date is June 27, 2020, 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 27, 2021. 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. The senior lenders completed their mid-year review in October 2019 and given the 23 gross (12.97 net) wells that have come online since the last borrowing base redetermination, they increased the borrowing capacity to US$177.5 million providing additional liquidity. As at November 19, 2019, the facility is drawn approximately US$134 million ($177 million). The undrawn capacity of the senior credit facility is approximately US$43 million and will facilitate the Company's execution of its drilling and completion program.

The credit facility is subject to certain non-financial covenants and the Company is in compliance with all of the covenants under the senior loan as at September 30, 2019.

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$160,000 as security in order to operate in North Dakota.

Summary of Quarterly Results

Three month period ended (in thousands, except per share amounts):	9/30/2019	6/30/2019	3/31/2019	12/31/2018	9/30/2018	6/30/2018	3/31/2018	12/31/2017
Oil and natural gas sales, net of royalties	$ 42,249	$ 24,419	$ 17,230	$ 20,899	$ 31,980	$ 29,246	$ 15,574	$ 8,171
Adjusted EBITDA	$ 29,996	$ 16,344	$ 9,581	$ 11,684	$ 22,018	$ 20,325	$ 10,910	$ 5,700
Cash flow from operating activities[1]	$ 32,275	$ (1,626)	$ 20,210	$ 19,810	$ 20,112	$ 21,734	$ 7,856	$ 2,333
Net income (loss)	$ 4,982	$ 1,733	$ (996)	$ 7,982	$ 10,449	$ 6,274	$ 2,351	$ (1,482)

[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 in the third quarter of 2019 increased substantially compared to the second quarter of 2019 due to a 93% increase in production, partially offset by lower realized commodity prices. The same factors led to significant increases in adjusted EBITDA, cash flow from operations and net income in the third quarter of 2019. Revenue in the second quarter of 2019 increased compared to the first quarter due to a 18% increase in production volumes and higher realized oil prices. This increase in revenue also resulted in net income in the second quarter of 2019 compared to a net loss in the first quarter of 2019. Cash flow from operations decreased in the second quarter of 2019 compared to the first quarter as a result of an increase in accounts receivable. Revenue in the first quarter of 2019 declined compared to the fourth quarter of 2018 due to lower production volumes as well as lower benchmark commodity prices. Despite a reduction in revenues, cash flow from operations increased due to a large decrease in working capital. Net income moved to a small loss in the first quarter of 2019 following the reduction in revenues and a large deferred tax recovery in the fourth quarter of 2018. Revenue in the fourth quarter of 2018 declined compared to the third quarter due to lower production volumes and both weaker benchmark commodity prices and wider Bakken oil differentials. Net income decreased over the period as a result of the aforementioned factors. 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 and acquisitions. 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.

The Company has made several acquisitions and participated in drilling programs which have generally increased production volumes since 2017.

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 changes in economic conditions impact crude oil and natural gas prices, royalties and operating costs. 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 report prepared as at December 31, 2018. The Company performed an internal review of its reserves as at August 31, 2019 reflecting recently acquired assets and production which was utilized in determining the depletion and depreciation expense in the third quarter of 2019.

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 necessitates 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 16 – *Leases*
The Company adopted IFRS 16, Leases, on January 1, 2019. IFRS 16 introduces a single lease accounting model for leases which requires a right-of-use asset and lease obligation to be recognized on the balance sheet for contracts that are, or contain, a lease. The Company used the modified retrospective adoption approach to adopt the new standard. The modified retrospective approach does not require restatement of prior period financial information as it applies the standard prospectively.

On initial adoption, the Company has elected to recognize right-of-use assets based on the corresponding lease obligation. Right-of-use assets and lease obligations of $0.3 million were recorded as of January 1, 2019, with no impact on retained earnings. When measuring the present value of lease obligations, the Company discounted remaining lease payments using its incremental borrowing rate at January 1, 2019, which was a weighted-average rate of 6.5%. The recognition of the present value of the lease obligations, which were previously classified as operating leases, resulted in increases to assets, liabilities, depletion and depreciation and finance costs and decreases to operating and general and administrative costs.

The right-of-use assets and lease obligations recognized primarily relate to the Company's office lease.

The Company has elected to apply practical expedients to not recognize right-of-use assets and lease obligations for short term leases that have a lease term of 12 months or less, and leases of low-value assets.

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, safety and performance risks associated with drilling and well completion activities, 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. There is risk that the Company may not realize the anticipated benefits of acquired properties or future development thereof.

The Company minimizes operational risks by engaging experienced service providers on our operated properties and by participating with well-established operators of our non-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 common or preferred 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.

As at September 30, 2019 the Company had no outstanding commodity price hedges.

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 above mentioned 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 or fixed price physical contracts 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 regulatory 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:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Cash flow from operating activities	$ 32,275	$ 20,112	$ 50,859	$ 49,702
Change in non-cash working capital	(2,279)	1,906	5,062	3,551
Adjusted EBITDA	$ 29,996	$ 22,018	$ 55,921	$ 53,253

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

(in thousands)	September 30, 2019	September 30, 2018
Total liabilities	$ 359,603	$ 185,255
Decommissioning obligation	(5,540)	(4,685)
Financial derivative liability	-	(2,966)
Lease Liability	(159)	- -
Current assets	(52,039)	(27,323)
Net debt	$ 301,865	$ 150,281

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.

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CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION
(UNAUDITED)

As at (thousands of Canadian dollars)	NOTE	September 30, 2019	December 31, 2018
ASSETS			
Current assets			
Cash and cash equivalents		$ 1,256	$ 491
Accounts receivable		50,091	26,677
Prepaid expenses and deposits		692	213
		52,039	27,381
Non-current assets			
Restricted cash	12	312	273
Deferred income tax asset		-	3,305
Right-of-use asset	3	152	-
Property, plant and equipment	4	502,966	373,063
		503,430	376,641
		$ 555,469	$ 404,022
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		$ 99,065	$ 44,049
Lease liability	6	159	-
		99,224	44,049
Non-current liabilities			
Senior loan	7	165,157	71,398
Deferred income tax liability		1,501	-
Preferred share obligation	8	88,181	88,912
Decommissioning obligation	5	5,540	4,934
		260,379	165,244
Total liabilities		359,603	209,293
SHAREHOLDERS' EQUITY			
Common shares	9	201,139	200,651
Preferred share equity component	8	7,510	7,510
Contributed surplus	9	5,928	5,444
Deficit		(22,294)	(28,013)
Accumulated other comprehensive income		3,583	9,137
		195,866	194,729
Commitments	12		
Subsequent events	16		
		$ 555,469	$ 404,022

See accompanying notes to the consolidated interim financial statements.

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CONSOLIDATED INTERIM STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(UNAUDITED)

(thousands of Canadian dollars, except per share amounts)	NOTE	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Revenue					
Petroleum and natural gas	10	$ 52,887	$40,123	$ 104,689	$95,566
Royalties		(10,638)	(8,143)	(20,791)	(18,766)
		42,249	31,980	83,898	76,800
Other income and loss					
Realized loss on financial derivatives		-	(2,348)	-	(5,453)
Unrealized gain on financial derivatives		-	2,222	-	350
		-	(126)	-	(5,103)
		42,249	31,854	83,898	71,697
Expenses					
Production and operating		8,534	5,191	19,940	12,937
Transportation		2,686	979	4,705	1,837
General and administrative		1,033	1,444	3,332	3,320
Depletion and depreciation	3,4	16,260	9,855	31,172	23,195
Finance	13	4,802	3,559	13,136	9,784
Share-based compensation	9	427	377	1,180	1,550
		33,742	21,405	73,465	52,623
Net income before income taxes		8,507	10,449	10,433	19,074
Deferred income tax expense		(3,525)	-	(4,714)	-
Net income		4,982	10,449	5,719	19,074
Currency translation adjustment		2,104	(1,808)	(5,554)	3,581
Comprehensive income for the period		$ 7,086	$ 8,641	$ 165	$22,655
Net income per common share, basic	11	$ 0.03	$ 0.06	$ 0.03	$ 0.12
Net income per common share, diluted	11	$ 0.03	$ 0.06	$ 0.03	$ 0.11

See accompanying notes to the consolidated interim financial statements.

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CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(UNAUDITED)

For the nine months ended September 30, 2019 and 2018

(thousands of Canadian dollars, except share amounts)

	Voting Common Shares			Preferred Share Equity Component			Accumulated Other Comprehensive Income (Loss)	
	Shares	Amount	Warrants		Contributed Surplus	Deficit		Shareholders' Equity
Balances, December 31, 2017	157,137,767	$ 142,379	$ 684	$ -	$ 3,547	$ (55,069)	$ (2,892)	$ 88,649
Issuance of voting common shares by prospectus, net of issue costs	24,865,300	42,455	-	-	-	-	-	42,455
Issuance of voting common shares by private placement, net of issue costs	6,756,905	12,460	-	-	-	-	-	12,460
Issuance of Preferred shares - equity component	-	-	-	10,041	-	-	-	10,041
Exercise of warrants to purchase common shares for cash	2,000,000	2,184	(684)	-	-	-	-	1,500
Exercise of options to purchase common shares for cash	30,000	36	-	-	(15)	-	-	21
Share-based compensation, gross	-	-	-	-	1,793	-	-	1,793
Net income	-	-	-	-	-	19,074	-	19,074
Other comprehensive income	-	-	-	-	-	-	3,581	3,581
Balances, September 30, 2018	190,789,972	$ 199,514	$ -	$ 10,041	$ 5,325	$ (35,995)	$ 689	$ 179,574
Balances, December 31, 2018	191,758,236	$ 200,651	$ -	$ 7,510	$ 5,444	$ (28,013)	$ 9,137	$ 194,729
Purchase of common shares for cancellation	(90,000)	(86)	-	-	-	-	-	(86)
Settlement of RSUs	502,007	574	-	-	(1,031)	-	-	(457)
Share-based compensation, gross	-	-	-	-	1,515	-	-	1,515
Net income	-	-	-	-	-	5,719	-	5,719
Other comprehensive loss	-	-	-	-	-	-	(5,554)	(5,554)
Balances, September 30, 2019	192,170,243	$ 201,139	$ -	$ 7,510	$ 5,928	$ (22,294)	$ 3,583	$ 195,866

See accompanying notes to the consolidated interim financial statements.

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CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS
(UNAUDITED)

(thousands of Canadian dollars)	NOTE	Nine Months ended September 30, 2019	2018
Operating Activities			
Net income		$ 5,719	$ 19,074
Operating items not affecting cash:			
Depletion and depreciation		31,172	23,195
Deferred income tax		4,714	-
Unrealized gain on financial derivatives		-	(350)
Share-based compensation		1,180	1,550
Finance		13,136	9,784
Change in non-cash working capital	14	(5,062)	(3,551)
		50,859	49,702
Investing Activities			
Acquisition of property, plant and equipment	4	(3,667)	(92,090)
Additions to property, plant and equipment	4	(167,471)	(73,201)
Change in non-cash working capital	14	38,209	(18,084)
		(132,929)	(183,375)
Financing Activities			
Proceeds from convertible preferred share issuance, net	8	-	89,990
Proceeds from share issuances, net	9	-	54,915
Proceeds from exercise of warrants		-	1,500
Proceeds from exercise of options		-	21
Payment of lease liabilities		(144)	-
Purchase of common shares for cancellation		(86)	-
Settlement of RSUs		(457)	-
Repayment of subordinated loan, net		-	(30,993)
Proceeds from senior loan, net	7	96,312	9,401
Payment of interest and preferred dividends	13,14	(11,134)	(5,944)
		84,491	118,890
Change in cash and cash equivalents		2,421	(14,783)
Effect of foreign exchange rate changes		(1,656)	1,656
Cash and cash equivalents, beginning of period		491	18,421
Cash and cash equivalents, end of period		$ 1,256	$ 5,294

See accompanying notes to the consolidated interim financial statements.

1. BUSINESS AND NATURE OF OPERATIONS

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

The Company's Corporate head office is located at Suite 3230, 421 - 7th Avenue SW, Calgary, Alberta. The Company's US head office is located at 303 E. 17th Avenue, Suite 940, Denver, CO.

2. BASIS OF PREPARATION

These consolidated interim financial statements and the notes thereto should be read in conjunction with the Company's audited consolidated financial statements as at and for the year ended December 31, 2018 and do not include all the information required for full annual financial statements.

These consolidated interim financial statements are unaudited and have been prepared in accordance with IAS 34 – "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC").

These consolidated interim financial statements have been prepared using the historical cost basis, except for financial derivative instruments which are measured at fair value.

These consolidated interim financial statements include the accounts of the Company and its wholly-owned subsidiary, PetroShale (US), Inc. The Company's presentation and functional currency is the Canadian dollar. The functional currency of the Company's US subsidiary is the US dollar, and its results and balance sheet items are translated to Canadian dollars, for purposes of these consolidated financial statements, in accordance with the Company's foreign currency translation accounting policy.

These consolidated interim financial statements were approved by the Company's Board of Directors on November 19, 2019.

The accounting policies applied for the consolidated interim financial statements as at and for the three and nine months ended September 30, 2019 are consistent with those applied for the financial statements as at and for the most recent audited period, except as follows.

Adoption of IFRS 16 – *Leases*

In January 2016 the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases* and IFRIC 4 *Determining Whether an Arrangement Contains a Lea*se. The Company adopted the new standard on January 1, 2019 which provides a single recognition and measurement model for lessees to recognize assets and liabilities for contracts that are, or contain, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The Company recognizes a right-of-use asset (''ROU") and a lease liability at the lease commencement date. The ROU asset and lease liability recognized relate to the Company's head office lease in Denver. The ROU asset is initially measured at cost based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date. The assets are depreciated to the earlier of the end of the useful life of the ROU asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. PetroShale presents ROU as its own line item on the consolidated statement of financial position. In addition, the ROU is periodically reduced by

impairment losses, if any, and adjusted for certain re-measurements of the lease liability. The average depreciation term is 0.8 years.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is re-measured in this way, a corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in profit or loss if the carrying amount of the ROU asset has been reduced to zero. Lease payments are applied against the lease obligation, with a portion reflected as interest expense using the effective interest rate method. PetroShale presents the lease liability as its own line item on the consolidated statement of financial position.

PetroShale has used the modified retrospective approach, which does not require restatement of prior period financial information as it applies the standard prospectively. The effect of initially applying the standard was an $0.3 million increase to ROU assets, with a corresponding lease liability recorded. The ROU asset was measured at the amount equal to the lease liability on January 1, 2019 with no impact on deficit. The lease liability was measured at the present value of the remaining lease payments, discounted using PetroShale's incremental borrowing rate as at January 1, 2019. The weighted average incremental borrowing rate used to determine the lease obligation on adoption was approximately 6.5 percent based on the Company's total cost of debt and preferred share financing.

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions related to the application of IFRS 16 include

- Incremental borrowing rate: The incremental borrowing rate is based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease obligation, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term.

The Company has elected to apply practical expedients to not recognize right-of-use assets and lease obligations for short term leases that have a lease term of 12 months or less, and leases of low-value assets are not considered material at September 30, 2019.

3. RIGHT-OF-USE-ASSET

The following table reflects the Company's right-of-use asset:

Balance at January 1, 2019	$ 298
Depreciation	(138)
Effect of foreign exchange rate changes	(8)
Balance as at September 30, 2019	$ 152

See note 2 for more information on IFRS 16 and our accounting policy regarding leases and right-of-use assets.

4. PROPERTY, PLANT AND EQUIPMENT

	Developed and Producing Assets	Other	Total
Balances as at December 31, 2017	$ 184,081	$ 91	$ 184,172
Acquisitions	93,520	-	93,520
Additions	101,532	160	101,692
Depletion and depreciation	(30,977)	(59)	(31,036)
Effect of foreign exchange rate changes	24,696	19	24,715
Balances as at December 31, 2018	372,852	211	373,063
Acquisitions	3,667	-	3,667
Additions	168,349	88	168,437
Depletion and depreciation	(30,886)	(148)	(31,034)
Effect of foreign exchange rate changes	(11,160)	(7)	(11,167)
Balances as at September 30, 2019	$ 502,822	$ 144	$ 502,966

Acquisitions

For the nine months ended September 30, 2019 the Company acquired $3.7 million of non-producing properties.

Depletion, Depreciation, and Future Development Costs

For the nine months ended September 30, 2019 and 2018, the Company recorded $31.0 million and $23.2 million, respectively, of depletion and depreciation expense in relation to property, plant and equipment, which reflected an estimated US$335 million and US$367 million, respectively of future development costs associated with proven plus probable reserves.

Impairment Charges

As at September 30, 2019 there were no facts or circumstances which suggested there is a trigger for impairment of the Company's Developed and Producing Assets. Therefore an impairment test was not required.

Capitalized Overhead

During the nine months ended September 30, 2019, the Company capitalized $803,000 of general and administrative costs and $335,000 of share-based compensation, which are directly attributable to the acquisition and exploitation activities of certain of its personnel in relation to the Company's operated properties ($983,000 and $243,000, respectively for the nine months ended September 30, 2018).

5. DECOMMISSIONING OBLIGATION

Balance as at December 31, 2017	$	2,473
Acquisition of petroleum and natural gas properties		1,429
Additions		570
Revisions of estimated cash flows		76
Accretion		73
Effect of foreign exchange rate changes		313
Balance as at December 31, 2018		4,934
Acquisitions of petroleum and natural gas properties		275
Additions		379
Accretion		100
Effect of foreign exchange rate changes		(148)
Balance as at September 30, 2019	$	5,540

The Company's decommissioning obligation consists of remediation obligations resulting from its ownership interests in petroleum and natural gas assets. The total obligation is estimated based on the Company's net working interest in wells and related facilities, estimated costs to return these sites to their original condition, costs to plug and abandon wells and the estimated timing of the costs to be incurred in future years.

The total undiscounted amount of estimated future cash flows required to settle the obligation as at September 30, 2019 is $11.2 million (December 31, 2018 – $9.7 million) which includes an annual inflation factor of 2.4% (December 31, 2018 – 2.4%) applied to the estimated future costs of decommissioning and assumes that the liabilities are settled over approximately the next 40 years in accordance with estimates prepared by independent engineers. The estimated future cash flows as at September 30, 2019 have been discounted at the risk-free interest rate of 3.1% (December 31, 2018 – 3.1%).

6. LEASE LIABILITY

At September 30, 2019 the Company had future commitments relating to a lease liability as follows:

Total lease payments	$ 164
Discounting interest	(5)
Present value of lease payments	$ 159

As the future lease payments are all due within the next 12 months, the lease liability is presented as a current liability on the statement of financial position. Cash flow from financing activities for the nine months ended September 30, 2019 was $0.1M lower due to the deduction of the lease payments related to the Company's lease liabilitywhile cash flow from operating activities increased $0.1M.

See note 2 for more information on IFRS 16 and our accounting policy regarding leases and right-of-use assets.

7. DEBT

	Senior Loan	Subordinated Loan	Total Debt
Balances as at December 31, 2017	$ 49,891	$ 30,640	$ 80,531
Proceeds from (repayment of) loans, net	16,492	(30,993)	(14,501)
Net change in unamortized fees	-	108	108
Effect of foreign exchange rate changes	5,015	245	5,260
Balances as at December 31, 2018	71,398	-	71,398
Proceeds from loans, net	96,312	-	96,312
Effect of foreign exchange rate changes	(2,553)	-	(2,553)
Balances as at September 30, 2019	$ 165,157	$ -	$ 165,157

Senior Loan

The Company's senior loan is a revolving credit facility, which as at September 30, 2019 had a borrowing base of US$140.0 million ($185 million). The facility terms out on June 27, 2020, at which point, the facility can be extended at the option of the lenders, or if not extended, the facility would be converted to a non-revolving facility with a term maturing on June 27, 2021. This facility is secured by all of the Company's assets. The facility bears interest at the bank's prime lending rate, bankers' acceptance rates or US$ LIBOR rates plus a margin which is determined by the Company's senior debt to EBITDA ratio. EBITDA used for determining this ratio is defined in our senior loan agreement ("bank EBITDA") and may be different from that measurement referred to in the Company's other disclosures including its Management's Discussion & Analysis. During the three months ended September 30, 2019, the effective interest rate for the Company's LIBOR borrowings was 4.3% per annum (4.2% - December 31, 2018).

The borrowing base capacity of the senior loan facility is subject to a review performed at least twice annually by the lenders, based on reserve reports associated with the Company's U.S. petroleum and natural gas

properties. A decrease in the borrowing base could result in the requirement to make a repayment to the lenders. The senior lenders completed their review of the Company's year end 2018 reserves and agreed to increase the borrowing base capacity of the facility from US$125 million to US$140 million in June 2019. The senior lenders completed their review of mid-year reserves in October 2019, and increased the borrowing base capacity of the facility to US$177.5 million (see Note 16). All other terms and conditions of the Company's credit facility remain unchanged.

The credit facility is subject to certain non-financial covenants and the Company is in compliance with all of the covenants under the senior loan as at September 30, 2019.

The facility was drawn approximately US$124.7 million as at September 30, 2019 (December 31, 2018 – US$52.4 million).

8. PREFERRED SHARES

	Number of Preferred Shares	Liability Component	Equity Component
Balances as at December 31, 2017			
Issuance of preferred shares	75,000	$ 79,949	$ 10,041
Accretion	-	2,099	-
Effect of foreign exchange rate changes	-	6,864	-
Deferred tax liability	-	-	(2,531)
Balances as at December 31, 2018	75,000	$ 88,912	$ 7,510
Accretion	-	1,890	-
Effect of foreign exchange rate changes	-	(2,621)	-
Balances as at September 30, 2019	75,000	$ 88,181	$ 7,510

The preferred shares have a maturity date of January 25, 2023, which may be extended at the option of the Investor by one year. The preferred shares entitle the Investor to a cumulative annual dividend of 9.0% per annum, payable quarterly, except that no dividends shall be payable for the extension year, if any. The Company may elect to defer up to two quarterly dividend payments per twelve month period, subject to a cumulative limit of six quarterly dividend payments over the term of the preferred shares and only following the first anniversary of the issuance date. Any deferred dividend payments accrue at a rate of 12.0% per annum and are added to the issuance amount of the preferred shares to determine the redemption obligation at maturity or the amount which may be converted to common shares at the option of the Investor. The preferred shares may be converted by the Investor, in whole or in part, into common voting shares of the Company at a price of $2.40 per share and using an exchange rate of C$1.00 = US$0.795, following the first anniversary of the issuance date. As part of the financing, the Investor acquired voting preferred shares of the Company which entitle the Investor to the "as-exchanged" voting rights of the preferred shares. The Company may elect to redeem the preferred shares prior to the maturity date, by making a "make-whole" premium payment in addition to the maturity redemption amount otherwise determined. The make-whole premium is 5% of the redemption amount otherwise determined if redemption occurs prior to the third anniversary of the issuance date, 2.5% if made after the third anniversary date but before the fourth anniversary date, and is nil if made after the fourth anniversary. The Company's ability to exercise this early

redemption right is conditional on the Company's common shares having a certain minimum price and minimum amount of trading liquidity in the thirty days preceding the optional redemption date.

9. SHARE CAPITAL

a) Share capital

The following table reflects the Company's outstanding common shares as at September 30, 2019:

Balance as at December 31, 2017	157,137,767	$ 142,379
Issuance of common shares by prospectus, net of issue costs	24,865,300	42,451
Issuance of common shares by private placement, net of issue costs	6,756,905	12,460
Exercise of warrants to purchase common shares	2,000,000	2,184
Exercise of options to purchase common shares	998,264	1,177
Balance as at December 31, 2018	191,758,236	$ 200,651
Purchase of common shares for cancellation	(90,000)	(86)
Settlement of RSUs	502,007	574
Balance as at September 30, 2019	192,170,243	$ 201,139

b) Normal course issuer bid:

On February 7, 2019, the Company announced that the TSX Venture Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 9,839,663 voting common shares of the Company between February 8, 2019 and February 8, 2020. During the nine months ended September 30, 2019, the Company purchased and cancelled 90,000 shares at an average price of $0.96 per Common Share for a total repurchase cost of $86 thousand.

c) Stock options

The following table presents stock option activity :

	Number of Options		Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)
Balance as at December 31, 2017	1,548,264	$	0.70	2.13
Exercised	(998,264)		(0.70)	(1.28)
Balance as at December 31, 2018 and September 30, 2019	550,000	$	0.70	1.81

As at September 30, 2019, all of the outstanding options were exercisable.

d) Restricted awards

The Company has granted restricted share bonus awards and performance share bonus awards (collectively,"awards") to certain directors, officers and employees. These awards expire before the end of the third year from the date of grant and vest annually in three tranches following the date of issuance. Performance share bonus awards are also subject to performance vesting terms which result in a multiplier of between 0 and 2 times applied to the number originally granted, based on performance relative to certain measures established by the Company's Board of Directors. The awards may be settled by the Company, in its sole discretion, in cash and/or common shares of the Company. The estimated fair value of the awards is determined based on the current market value of the Company's common shares at the dates of grant and giving consideration to anticipated forfeiture rates. A charge to income is reflected as share based compensation expense in the statement of operations over the vesting period with a corresponding increase to contributed surplus.

	Number of Awards		Estimated Fair Value Price
Balance as at December 31, 2017	2,625,000	$	1.80
Granted	710,000		1.58
Settled	(41,667)		(1.80)
Forfeited and expired	(108,333)		(1.80)
Balance as at December 31, 2018	3,185,000	$	1.75
Granted	2,821,500		0.75
Settled	(903,332)		(1.82)
Balance as at September 30, 2019	5,103,168	$	1.19

As at September 30, 2019, 4,012,968 awards were restricted share bonus awards and 1,090,200 were performance share bonus awards.

10. REVENUE

The following reflects our oil and natural gas revenue, before royalties:

	Three months ended September 30,		Nine months ended September 30,	
Revenue	**2019**	**2018**	**2019**	**2018**
Petroleum and natural gas	$ 52,887	$ 40,123	$104,689	$95,566

The Company has a number of different commodity sales as well as transportation and processing contracts related to production from its properties. To the extent control of the relevant commodity is transferred to the purchaser prior to transportation or processing, fees incurred are netted against the relevant revenue in the statement of operations. To the extent control of the relevant commodity is transferred to a purchaser after transportation or processing, fees incurred are reflected as transportation expense and as operating

expense, respectively in the statement of operations. Natural gas and natural gas liquids revenue are nominal in these periods.

The Company sells its production pursuant to variable-priced contracts. The transaction price is based on the relevant commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Commodity prices are based on market indices that are determined on a monthly or daily basis.

11. NET INCOME PER COMMON SHARE

The following table presents the Company's net income per common share:

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except for share and per share data)	**2019**	**2018**	**2019**	**2018**
Net income	$ 4,982	$ 10,449	$ 5,719	$19,074
Weighted average number of basic common shares	192,168,550	175,322,589	192,014,140	164,068,659
Weighted average number of basic and diluted common shares	197,273,567	179,017,367	197,191,551	167,820,840
Net income per weighted average basic common share	$ 0.03	$ 0.06	$ 0.03	$ 0.12
Net income per weighted average diluted common share	$ 0.03	$ 0.06	$ 0.03	$ 0.11

12. COMMITMENTS

The Company has an outstanding letter of credit in favor of an 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 in the amount of US$160,000 as security in order to operate in North Dakota.

The Company is committed to monthly rental payments for office space of $16,000 through July 2020 and monthly rental payments for compressor leases of $74,000 for a minimum of twelve months.

13. FINANCE

Nine months ended September 30	2019	2018
Interest - senior debt	$ 4,404	$ 1,958
Interest - subordinated loan	-	244
Dividends - Preferred Shares	6,730	5,948
Accretion of Preferred Shares	1,890	1,481
Operating lease interest	12	-
Accretion of decommissioning obligation	100	45
Other finance expense	-	108
Finance Expense	$ 13,136	$ 9,784

14. SUPPLEMENTAL CASH FLOW DISCLOSURES

Changes in non-cash working capital are comprised of:

	Nine months ended September 30, 2019	2018
Source / (use) of cash:		
Accounts receivable	$ (23,414)	$ (11,613)
Prepaid expenses and deposits	(479)	(17)
Accounts payable and accrued liabilities	55,016	(6,809)
	$ 31,123	$ (18,439)
Related to operating activities	$ (5,062)	$ (3,551)
Related to investing activities	38,209	(18,084)
Accrued and unpaid dividends on preferred shares	-	2,206
Difference due to foreign exchange	(2,024)	990
	$ 31,123	$ (18,439)
Interest and preferred dividends paid	$ 11,134	$ 5,944
Income taxes paid	nil	nil

15. SEGMENT DISCLOSURES

The Company operates in one industry segment, the production of petroleum and natural gas and development of oil and natural gas properties.

The Company and its subsidiary operated in two geographical segments during the periods reported below, being Canada and the United States.

	Three months ended September 30,		Nine months ended September 30,	
	2019	**2018**	**2019**	**2018**
Revenue, net of royalties				
United States	$ 42,232	$ 31,964	$ 83,848	$ 76,752
Canada	17	16	50	48
	$ 42,249	$ 31,980	$ 83,898	$ 76,800
Net income (loss)				
United States	$ 5,614	$ 10,958	$ 7,165	$ 21,175
Canada	(632)	(509)	(1,446)	(2,101)
	$ 4,982	$ 10,449	$ 5,719	$ 19,074

As at	**September 30, 2019**	**December 31, 2018**
Property, plant and equipment		
United States	$ 502,423	$ 372,493
Canada	543	570
	$ 502,966	$ 373,063

16. SUBSEQUENT EVENTS

In October 2019, the lenders to the senior loan facility agreed to increase the borrowing base capacity of the facility from US$140 million to US$177.5 million ($234 million). As at the date of these financial statements, the facility is drawn US$134 million ($177 million). The Company also closed a small acquisition in October 2019, which adds 3.5 net drilling locations that are expected to come online over the course of 2020.