PetroShale
Calgary • Denver

Management's Discussion & Analysis

As at September 30, 2015
and for the three and nine months ended September 30, 2015 and 2014

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 12, 2015. This MD&A reports on the consolidated financial position and the consolidated results of operations of PetroShale for the three and nine months ended September 30, 2015 and 2014 and should be read in conjunction with PetroShale's consolidated interim financial statements as at and for the three and nine months ended September 30, 2015 and the consolidated financial statements for the year ended December 31, 2014. The reader should be aware that historical results are not necessarily indicative of future performance.

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

Frequently Used Terms:

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

Barrel of Oil Equivalent

Where amounts are expressed on a barrel of oil equivalent ("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. Given the value ratio, based on the current price of crude oil compared to natural gas, is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, 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 costs, 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 its results and balance sheet items are translated to Canadian dollars for purposes of consolidation in PetroShale's financial statements, in accordance with the Company's foreign currency translation accounting policy.

Non-IFRS Measurements

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

The reconciliation between these amounts and that defined by IFRS can be found later within 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, production estimates, expected commodity mix and prices, impact of hedges, future operating costs, expected royalty rates, expected general and administrative expenses, expected interest rates, debt levels, funds from operations and the timing of and impact of implementing new accounting policies, estimates regarding undeveloped land position and estimated future drilling, recompletion or reactivation locations and anticipated impact upon PetroShale's forecasts in respect of production and cash flow for the remainder of fiscal year 2015 and resulting fiscal year-end net debt may constitute forward looking statements and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, risks associated with PetroShale's non-operated status on the majority of its properties, production delays resulting from or inability to obtain required regulatory approvals or the tie-in of associated natural gas production and 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 and political environment in which PetroShale operates; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the respective operator of each project which the Company has an interest in to operate the field in a safe, efficient, compliant and effective manner; PetroShale's ability to obtain financing on acceptable terms; changes in the Company's various credit facilities; field production rates and decline rates; the ability to manage operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the ability to convert proven non-producing 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 product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; and PetroShale's ability, or those of the operators of its properties, to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive.

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

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(all $ amounts are presented in Canadian dollars)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
FINANCIAL *(in thousands, except per share and share data)*				
Oil and natural gas revenue	$ 7,482	$ 2,085	$ 17,358	$ 6,148
Funds flow from operations [1]	$ 1,002	$ (156)	$ 1,427	$ 232
Net loss	$ (3,042)	$ (892)	$ (7,404)	$ (2,024)
Per share - basic and diluted	$ (0.09)	$ (0.03)	$ (0.22)	$ (0.06)
EBITDA [1]	$ 3,292	$ 649	$ 7,432	$ 1,677
Capital expenditures	$ 18,466	$ 26,732	$ 36,793	$ 46,509
Net debt[2]			$ 109,879	$ 43,737
Common shares outstanding			34,207,574	34,207,574
Weighted average - basic and diluted	34,207,574	34,207,574	34,207,574	31,393,655
OPERATING				
Number of Days	92	92	273	273
Daily production				
Crude oil (Bbls)	1,566	240	1,176	228
Natural gas (Mcf)	1,339	47	737	60
Barrels of oil equivalent (Boe)	1,789	248	1,299	238
Average realized price [3]				
Crude oil ($/Bbl)	$ 49.14	$ 93.27	$ 51.87	$ 96.61
Natural gas ($/Mcf)	$ 3.27	$ 5.29	$ 3.49	$ 8.36
Netback per Boe ($) [1]				
Revenue	$ 45.45	$ 91.40	$ 48.94	$ 94.72
Royalties	$ (9.98)	$ (19.38)	$ (10.83)	$ (20.98)
Realized loss on hedge	$ -	$ (1.14)	$ -	$ (0.82)
Operating costs and production taxes	$ (11.44)	$ (18.59)	$ (11.59)	$ (18.30)
Operating netback	$ 24.03	$ 52.29	$ 26.52	$ 54.62
Operating netback prior to hedging	$ 24.03	$ 53.43	$ 26.52	$ 55.44
Operating netback prior to hedging, on a net of royalty basis	$ 30.88	$ 67.85	$ 34.10	$ 71.24

[1] *Non-IFRS measure - See page 2 and the tables on pages 18-19.*

[2] *Total liabilities, excluding decommissioning obligation and any liabilities related to financial derivatives, less total current assets, excluding any financial derivative assets.*

[3] *Before the effects of hedging.*

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.

THIRD QUARTER 2015 SIGNIFICANT EVENTS

Oil and Gas Acquisitions and Development

During the quarter, the Company acquired 242 net acres and 9 gross (0.90 net) producing wells, of which 0.39 net wells were newly producing, in the core of PetroShale's focus area. Further, the Company participated in drilling and completing 1.25 net wells, of which the Company brought into production 0.14 net wells during the quarter. Total acquisitions and capital additions for the quarter were US$14.1 million.

Financing

The Company's senior lender re-affirmed the existing borrowing base under the senior loan, despite lower oil prices, reflecting increases in the Company's reserves and production levels.

Oil Prices

World oil prices decreased in the third quarter with WTI averaging in the mid $40's, and although slightly offset by improving differentials in the Company's operating area, this negatively impacted our realized pricing and operating netback. Despite low oil prices, our netback was $24.03 for the third quarter ($30.88 on a net of royalty basis), and EBITDA was positive at $3.3 million.

OUTLOOK

The Company continues to pursue additional land in our core focus area and we look forward to continuing to update our shareholders on our progress.

RESULTS OF OPERATIONS

Production

The following table summarizes the Company's working interest (gross of royalty) daily production volumes for the relevant periods.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Crude oil (Bbl per day)	1,566	240	1,176	228
Natural gas (Mcf per day)	1,339	47	737	60
Total (Boe per day)	1,789	248	1,299	238
Liquids % of Production	88%	97%	91%	96%

Daily production for the three months ended September 30, 2015 increased compared to the prior period ended September 30, 2014 through a combination of the Company's participation in drilling and completing new wells and the acquisition of producing wells. The Company's gas production as a percentage of total production has increased in 2015 as more wells are being tied in to gas infrastructure. The Company also acquired producing properties late in the fourth quarter of 2014 which had a positive impact on production in the nine months ended September 30, 2015.

Production increased 34% compared to the second quarter 2015 average of 1,340 Boe per day for the reasons noted above.

Pricing

Average benchmark prices	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Crude oil – WTI				
(US$ per Bbl)	$ 46.65	$ 97.73	$ 50.93	$ 99.86
Natural gas – HH				
(US$ per Mcf)	2.76	3.96	2.80	4.59
Exchange rate (US$ /CAD$)	$ 1.30	$ 1.09	$ 1.26	$ 1.10

Realized prices (CAD)				
Crude oil ($ per Bbl)	$ 49.14	$ 93.27	$ 51.87	$ 96.61
Natural gas ($ per Mcf)	3.27	5.29	3.49	8.36
Per Boe	$ 45.45	$ 91.40	$ 48.94	$ 94.72

Realized prices (USD)				
Crude oil ($ per Bbl)	$ 38.27	$ 85.32	$ 41.12	$ 87.59
Natural gas ($ per Mcf)	2.57	4.71	2.80	7.70
Per Boe	$ 35.41	$ 83.53	$ 38.79	$ 85.76

Management analyzes the basis differential between WTI and the actual realized price for the sale of its crude oil as WTI is a reasonable proxy for the market in which its oil is sold. The average differential between the Company's realized crude price to WTI during the three months ended September 30, 2015 was US$8.38, which has improved from US$12.41 in the same period in 2014 and US$10.05 in the second quarter of 2015. Although slightly offset by the weakness of the Canadian dollar, much lower benchmark prices resulted in lower Canadian dollar realized prices in the current reporting period. The realized natural gas price is lower than the corresponding prior period due to a decline in the benchmark Henry Hub price and the elimination of the positive differential to that benchmark. Due to the implementation of more strict gas conservation measures by the regulator in North Dakota, and associated higher processing and capture costs, net realized prices for natural gas have not been as favorable in 2015.

Royalties

	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Royalties (in thousands)	$ 1,643	$ 442	$ 3,841	$ 1,362
Royalties per Boe	$ 9.98	$ 19.38	$ 10.83	$ 20.98
Royalties as % of Revenue	22.0%	21.2%	22.1%	22.2%

The royalty rate has remained relatively stable; however the royalties per Boe are lower in 2015 due to the lower realized prices in the period. Management anticipates the royalty per Boe will remain low until commodity prices recover, but the percentage of revenue to remain consistent.

Operating Costs and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Operating costs	$ 1,251	$ 245	$ 2,742	$ 727
Production taxes	632	179	1,369	461
Operating costs and production taxes (in thousands)	$ 1,883	$ 424	$ 4,111	$ 1,188
Operating costs per Boe	$ 7.60	$ 10.74	$ 7.73	$ 11.20
Production taxes per Boe	3.84	7.85	3.86	7.10
Operating costs and production taxes per Boe	$ 11.44	$ 18.59	$ 11.59	$ 18.30

Operating costs

The Company operates primarily in two main areas in the US: one is the Mondak area, which targets the upper Bakken shale formation; and the other is our core operating area in North Dakota, which targets the middle Bakken and Three Forks formations. Operating costs per Boe decreased for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 due to a larger portion of the production coming from our core North Dakota assets which have lower average operating expenses per Boe. Our North Dakota wells are typically organized as pad operations, which are more efficient. Total operating cost dollars have increased period over period consistent with increasing production volumes.

Production taxes

Production taxes are related to the Company's US properties. Currently, in North Dakota there is a 5% severance tax and a 6.5% oil extraction tax. North Dakota recently passed new tax legislation, effective January 1, 2016 reducing the extraction tax to 5% unless the average monthly WTI price is above $90 for three consecutive months at which time the rate would increase to 5.5%. As a result, we anticipate a decline in production taxes as a percentage of revenue in 2016.

Production taxes as a percentage of oil and natural gas revenues have been stable in the nine months ended September 30, 2015, compared to the prior period. Production taxes per Boe are significantly lower than the corresponding prior period due to lower realized prices.

Operating Netback

($ per Boe)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Revenue	$ 45.45	$ 91.40	$ 48.94	$ 94.72
Royalties	(9.98)	(19.38)	(10.83)	(20.98)
Realized hedge loss	-	(1.14)	-	(0.82)
Operating costs	(7.60)	(10.74)	(7.73)	(11.20)
Production taxes	(3.84)	(7.85)	(3.86)	(7.10)
Operating netback	$ 24.03	$ 52.29	$ 26.52	$ 54.62
Operating netback prior to hedging	$ 24.03	$ 53.43	$ 26.52	$ 55.44
Operating netback prior to hedging, on a net of royalty basis	$ 30.88	$ 67.85	$ 34.10	$ 71.24

Operating netbacks decreased during the three and nine month periods ended September 30, 2015 compared to the prior periods primarily due to the decline in world oil prices, which was partially offset by the corresponding reduction in royalty expense and production taxes, and a decline in operating costs.

General and Administrative Expense

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
General and administrative expense (in thousands)	$ 663	$ 627	$ 1,970	$ 1,851

General and administrative expense ("G&A") was consistent with the prior period.

Share-based Compensation

Share-based compensation expense reflects the value ascribed to stock options provided to employees and directors of the Company, and are calculated utilizing a fair value assessment methodology. The Company issued 20,000 stock options to employees in the nine months ended September 30, 2015. Share-based compensation was $181,000 for the nine months ended September 30, 2015 compared to $419,000 for the nine months ended September 30, 2014. This decrease was due to the completion of vesting periods of certain option grants prior to January 1, 2015 and during the nine months ended September 30, 2015.

Depletion and Depreciation Expense

	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Depletion and depreciation expense (in thousands)	$ 3,697	$ 540	$ 7,857	$ 1,449
Depletion and depreciation per Boe	$ 22.46	$ 23.67	$ 22.15	$ 22.30

Depletion and depreciation expense increased substantially during the three and nine month periods ended September 30, 2015 compared to the prior periods due to the corresponding increase in production volumes. The expense per Boe has remained consistent as reserves have increased consistent with production.

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. As at September 30, 2015 management determined that impairment indicators existed as a result of a further decline in oil and natural gas commodity prices. The Company performed an impairment test on its U.S. CGU which has a book value recorded in property, plant and equipment (the Company’s core North Dakota middle Bakken CGU) and determined no impairment was necessary.

Finance Expense

Finance expense reflects interest on the Company’s senior loan and subordinated loan, including the amortization of certain loan origination fees. Finance expense for the three and nine months ended September 30, 2015 increased over the comparative periods ended September 30, 2014 due to financing the acquisitions and capital expenditures undertaken in 2014 and the first nine months of 2015 primarily with debt. Additionally, the weakening of the Canadian dollar resulted in an increase in the interest expense on the US dollar based loan facilities. Finance expense will be higher in the fourth quarter than the third quarter as the senior loan balance increased from $18.8 million at June 30, 2015 to $26.7 million at September 30, 2015 and the subordinated loan balance increased from$61.3 million at June 30, 2015 to $71.1 million at September 30, 2015. Interest payments on the Company’s subordinated loan remain deferred during the period that the interest coverage covenant is waived under the senior loan.

Foreign Currency 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. For the three months ended September 30, 2015, the Company recognized a currency translation gain in other comprehensive income due to the weakening of the Canadian dollar against the US dollar during the period and the excess of U.S. dollar denominated assets over liabilities.

Share Capital

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Weighted average commonshares outstanding:				
Basic and diluted	34,207,574	34,207,574	34,207,574	31,393,655
Outstanding securities:				
Common shares, voting and non-voting			34,207,574	34,207,574
Stock options			2,295,205	2,275,205

As at November 12, 2015, 34,207,574 common shares and 2,295,205 stock options are outstanding.

The following stock options are outstanding as at September 30, 2015:

Stock Options

Exercise Prices	Weighted Average Remaining Contractual Term	Number of Outstanding Options	Number of Options Exercisable	Weighted Average Exercise Price
$0.70	3.15	943,264	314,419	$0.70
$1.11	4.01	20,000	-	$1.11
$1.40	3.45	275,000	91,666	$1.40
$1.50	1.47	1,056,941	1,056,941	$1.50
	2.42	2,295,205	1,463,026	$1.16

Capital Expenditures

The following table represents capital expenditures for the nine months ended September 30, 2015:

(in thousands)	
Acquisitions	$ 20,869
Capital expenditures	
Drilling and completion	15,453
Other	471
Total capital expenditures	$ 36,793

During the nine months ended September 30, 2015, the Company participated in 107 gross (2.50 net) wells, which were in various stages of completion.

The Company has no commitments to make additional capital expenditures. The Company's reserve report prepared by its independent engineers as at December 31, 2014, as updated by the Company's internal engineer to reflect new properties acquired during 2015, includes estimated future development costs of US$136.0 million for proven and probable reserves.

Liquidity and Capital Resources

Capital expenditures of $36.8 million for acquisitions and drilling and completion activities for the nine months ended September 30, 2015, as described above, were primarily financed through draws on the Company's senior loan and subordinated loan facilities. In addition, debt increased during the period as a result of the reduction of accounts payable balances, slightly offset by positive funds flow and proceeds from disposition of assets of $1.2 million.

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

The Company continuously monitors production, commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing its capital spending levels by not consenting to participate in additional drilling proposed by operators of its various properties or by selling its interest in those wells to other parties, as we did in the second quarter of 2015. The operators of the Company's properties are evaluating their capital programs in light of current commodity prices, and drilling activity has been and likely will continue to be deferred to some extent until oil prices recover. Accounts payable and accrued liabilities consist of amounts payable to operators of our properties relating to capital spending and field operating activities and suppliers relating to general and administrative expenses. Management expects to be able to fully meet all current obligations when due with funding provided by a combination of accounts receivable collections, funds from operations and available capacity under its credit facilities.

The Company maintains a senior revolving credit facility of US$22.5 million which is referred to as the senior loan under current liabilities in the statements of financial position. The maturity date is July 16, 2016. The amount of the facility is subject to a borrowing base test performed on a periodic basis and at least twice annually by the lender, based primarily on producing oil and natural gas reserves and using commodity prices estimated by the lender as well as other factors. A decrease in the producing reserves could result in a reduction to the credit facility, which may require a repayment to the lender. The lender recently completed its semi-annual review as at June 30, 2015 and re-affirmed the existing borrowing base.

The facility is subject to certain financial and non-financial covenants. The financial covenants consist of: (i) a consolidated cash flow to interest expense ratio, as defined in the loan agreement, which is not to be less than 2.50 to 1 on a rolling four-quarter basis, with any equity injections included in the calculation of consolidated cash flow and interest expense excluded from the definition of consolidated cash flow; and (ii) a requirement that total debt not exceed the borrowing base by more than 133%, while excluding the subordinated loan from the definition of total debt. The consolidated cash flow to interest expense ratio was 2.70 at the end of the third quarter. The Company obtained a waiver from this covenant in April (see below). The Company is in compliance with its other covenants. This facility was drawn to US$20.0 million as at September 30, 2015.

The Company also has a secured, subordinated revolving credit facility with its two largest shareholders. The maturity date on this facility is December 31, 2016. The facility is intended to allow the Company to close acquisitions and/or fund drilling and well completion capital expenditures. The credit facility bears interest at a rate of 12% per annum, with interest payments due monthly, and includes a 2.5% origination fee. The credit facility is provided by two significant shareholders of the Company, one of whom is also a Director and the CEO. The subordinated loan was drawn to US$53.4 million of the available capacity of $60.0 million as at September 30, 2015. The terms of the subordinated loan are similar to those which management believes could be negotiated with third parties.

Management has obtained a waiver from the consolidated cash flow to interest expense covenant under its senior revolving facility on the condition that interest payments under the subordinated loan are deferred until such time as the covenant is back in compliance, or until April 1, 2016, whichever is earlier. Interest payments under the subordinated loan have been deferred commencing April 1, 2015 and $4.3 million has been included in accounts payable. If the Company is successful in raising equity capital later in the year, proceeds therefrom can be added to cash flow for purposes of this covenant, which may allow interest payments on the subordinated loan to recommence at that time. A deferral of interest payments as a condition of the covenant waiver under the senior loan would normally result in an increase in the accrued interest rate under the subordinated loan of 5% per annum during the period that interest payments are deferred. However, the subordinated lenders have agreed to waive the interest rate increase in this circumstance, and for the period the interest deferral is required under the senior loan agreement.

The incremental liquidity provided by the undrawn capacity under the senior loan and the subordinated loan will assist the Company with meeting its capital needs in the upcoming quarters. The fact that the lenders to the subordinated loan facility are the Company's largest shareholders also affords incremental flexibility for the Company. The Company anticipates that future drilling activities on the Company's existing land base will support a larger borrowing base under its senior loan facility as its significant proven undeveloped and probable reserves are developed.

The Company retains the ability to carry out one or more equity financings to raise additional cash to fund future acquisitions, capital expenditures and/or repay outstanding debt. The Company's ability to complete an equity offering is dependent on market conditions.

Contractual Obligations

The following table lists the Company's contractual obligations as at September 30, 2015 and the expected timing of the settlement of these obligations.

(in thousands)	Contractual Cash Flow	Less than 1 Year	1-2 Years	3-5 Years	Thereafter
Accounts payable and accrued liabilities [1]	$ 18,161	$ 18,161	$ -	$ -	$ -
Operating leases (office rent)	231	120	111	-	-
Subordinated loan [2]	82,221	8,550	73,671	-	-
Senior loan[3]	27,531	27,531	-	-	-
Total	$ 128,144	$ 54,362	$ 73,782	$ -	$ -

(1)The amount includes deferred interest and fees payable of $4.3 million on the subordinated loan reflected in the financial statements.

(2)The amount differs from that presented on the statement of financial position due, in part, to the unamortized portion of loan origination fees and future interest expense at the fixed rate of 12.0% as at September 30, 2015. Although interest expense on this loan is currently deferred, the table reflects the full interest obligation related to the periods shown.

(3)Includes interest expense at the rate of 4.0% being the rate applicable at September 30, 2015.

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.

Letters 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 institutions that issued the letters of credit.

Summary of Quarterly Results

Three month period ended (in thousands):	9/30/2015	6/30/2015	3/31/2015	12/31/2014	9/30/2014	6/30/2014	3/31/2014	12/31/2013
Oil and natural gas sales, net of royalties	$ 5,839	$ 5,349	$ 2,329	$ 2,448	$ 1,643	$ 2,089	$ 1,054	$ 1,067
Net loss	(3,042)	(1,824)	(2,538)	(3,030)	(892)	(578)	(554)	(2,597)
Net loss per share –Basic and diluted	$ (0.09)	$ (0.05)	$ (0.07)	$ (0.09)	$ (0.03)	$ (0.02)	$ (0.02)	$ (0.09)

Factors that influenced quarterly variations

Quarter over quarter fluctuations are attributable to the items discussed below. For the quarter ended September 30, 2015, net revenue increased as increased production volumes were somewhat offset by declines in commodity prices. The net loss in this quarter reflects the impact of current oil prices and higher finance and depletion expenses. For the quarter ended June 30, 2015, net revenue increased from the quarter ended March 31, 2015 due to an increase in production and higher realized oil prices.

The loss in the quarter ended December 31, 2014 reflects impairments booked in that period. In the quarter ended September 30, 2014, revenue decreased over the prior quarter despite three new wells being completed and put on production during the quarter as this was more than offset by temporary field shut-ins of existing wells to accommodate completion operations on adjacent wells, plus the negative impact of weaker oil prices.

In the quarter ended December 31, 2013, the net loss reflects an impairment expense recognized of $1.9 million.

Generally, the Company acquired several projects over time and participated in drilling programs which have increased production and revenue.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Estimates and underlying assumptions are reviewed on an ongoing basis. Actual results may differ from these estimates.

Reserves

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

Decommissioning obligation

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

Business combinations

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

Share-based compensation

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

Deferred income taxes

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

New and Future Accounting Pronouncements

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

IFRS 11 – "Accounting for Acquisitions of Interests in Joint Operations" has been amended to provide guidance on accounting for acquisitions of an interest in a joint operation that constitutes a business. IFRS 11 is effective for annual periods beginning on or after January 1, 2016 with early adoption permitted. The impact of this amended accounting standard has not yet been determined.

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

Business Conditions and Risks

The Company is engaged in the acquisition, exploration, development and production of crude oil and natural gas assets. 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. Operational risks include the performance of the operators of the Company's properties, competition for land and services, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

During its start-up and land accumulation phase, 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.

During its operational phase, the Company minimizes its business risks by participating with well-established operators of its properties. Because it does not currently operate any of its existing US properties it has 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 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, it 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, 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 its business strategy. There is no guarantee that external sources of financing will be available in the future, on favorable terms or at all. The various sources of funding include:

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

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

Inflation risks subject the Company to potential erosion of product netbacks. 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's operators attempt to mitigate this risk by developing long-term relationships with suppliers and contractors and maintaining an appropriate inventory of production equipment.

The oil and natural gas industry has various environmental risks subject to regulation by various governmental bodies. Environmental legislation includes, but is not limited to, operational controls, site restoration and abandonment requirements and restrictions on emissions of various substances related to the production of oil and natural gas. The North Dakota Industrial Commission recently adopted new 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.

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:

- The operators of PetroShale's properties attempt to explore for and produce crude oil that is of high quality (light, sweet), mitigating its exposure to adverse quality differentials;
- Natural gas production will generally be connected to established pipeline infrastructure that operates with minimal interruptions;
- Sale arrangements are handled by individual operators, and will vary in term and pricing structure creating a diverse portfolio that minimizes risk of exposure to any one market; and
- Financial derivative instruments may be used where appropriate to manage commodity price volatility.

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

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

Non-IFRS Measures

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

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2015	2014	2015	2014
Cash flow from (used in) operating activities	$ 628	$ 446	$ 710	$ (116)
Decommissioning expenditures	-	84	2	84
Change in non-cash working capital	374	(686)	715	264
Funds flow from operations	$ 1,002	$ (156)	$ 1,427	$ 232

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

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2015	2014	2015	2014
Net loss	$ (3,042)	$ (892)	$ (7,404)	$ (2,024)
Add back:				
Finance expense	2,583	862	6,798	1,833
Depletion and depreciation	3,697	540	7,857	1,449
Foreign exchange (gain)	-	(2)	-	-
Share-based compensation	54	141	181	419
EBITDA	$ 3,292	$ 649	$ 7,432	$ 1,677

Off Balance Sheet Arrangements

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

Additional Information

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