

PetroShale Inc.
Management's Discussion & Analysis
For the three and nine months ended September 30, 2014 and 2013

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 14, 2014. This MD&A reports on the consolidated financial condition and the results of operations of PetroShale for the three and nine months ended September 30, 2014 and 2013, respectively 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, 2014 and the consolidated financial statements for the period ended December 31, 2013. The reader should be aware that historical results are not necessarily indicative of future performance.

The Company changed its financial year-end from June 30 to December 31 during 2013 in order to align its continuous disclosure reporting and shareholder meeting schedule with the majority of its oil and gas peer group, and facilitate peer comparisons. As a result of changing the Company's year-end, the current reporting period of the three and nine months ended September 30, 2014 has been presented with comparative information for the three and nine months ended September 30, 2013.

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

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. The term "Mboe" stands for thousands of barrels of oil equivalent.

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.

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 expenses 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, share-based compensation and other non-cash charges to income. 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) and cash flow from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

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

($ thousands)	Nine months ended September 30, 2014	20134
Cash flow from (used in) operating activities	$ (116)	$ 1,061
Decommissioning expenditures	84	-
Change in non-cash working capital	264	(340)
Funds flow from operations	$ 232	$ 721

The calculation of operating netback is found within this MD&A.

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

($ thousands)	Three Months Ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Net loss	$ (892)	$ (87)	$ (2,024)	$ (18,063)
Add back:				
Finance expense	862	120	1,833	257
Depletion and depreciation	540	432	1,449	1,070
Foreign exchange (gain) loss	(2)	(1)	-	191
Impairment of exploration and evaluation assets	-	-	-	13,965
Impairment of property, plant and equipment	-	-	-	3,262
Share-based compensation expense	141	153	419	488
EBITDA	$ 649	$ 617	$ 1,677	$ 1,170

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 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 fiscal year 2014 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, delays resulting from or inability to obtain required regulatory approvals 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 operator of the projects which the Company has an interest in to operate the field in a safe, efficient 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 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 a growing oil company engaged in the acquisition, development and consolidation of interests in the most prolific areas of the North Dakota Bakken.

SIGNIFICANT EVENTS

Oil and Gas Acquisitions and Development

During the nine months ended September 30, 2014, through a total of 21 transactions, the Company purchased oil and gas leases in McKenzie, Williams and Mountrail counties in North Dakota. This represents various working interests in existing and potential drilling units as well as Federal land, with associated proved undeveloped and probable reserves. For these mineral leases, the Company paid an aggregate amount of US$26.7 million, funded through a combination of credit facilities, existing cash resources and the issuance of 200,000 common shares. During the three months ended September 30, 2014, the Company paid US$13.3 million for mineral leases.

In addition to the oil and gas lease purchases described above, the Company also purchased working interests in wells, which were in the process of being drilled, and assumed capital obligations related to remaining drilling and completion of these wells for total consideration of US$1.3 million (US$0.2 million during the 3 months ended September 30, 2014) which includes assumption of decommissioning liabilities.

The assets acquired in the nine months ended September 30, 2014 are located within the Company's focus area in North Dakota. Drilling operations continued in our Stockyard area, and we commenced additional new wells in our other North Dakota properties, for a total development expenditure of US$10.7 million in the third quarter.

Reserves

The Company obtained an updated reserves report from its independent engineers, Netherland, Sewell, & Associates, on its US assets as at June 30, 2014. Reflecting acquisitions completed to that date, total proved plus probable US reserves increased from 656 Mboe as at December 31, 2013 (Net present value discounted at 10% ("PV10") –US$12.1 million) to 4,100 Mboe as at June 30, 2014 (PV10- US$63.5 million). These amounts do not reflect reserves associated with properties acquired in the third quarter.

Financing

In September 2014, the Company replaced its existing senior loan facility with a new senior credit facility from a Canadian bank. The new facility is a revolving credit facility with a borrowing base of US$10.0 million. The new facility is a demand facility, but has a renewal date of July 10, 2015, at which point, at the bank's option, it may be renewed on terms to be agreed upon at that time or converted to a non-revolving term facility.

In 2014, the Company entered into a subordinated loan financing with its two largest shareholders providing a revolving line of credit. The amount available under this facility was recently increased to US$50.0 million and the maturity date was extended to January 1, 2016 on existing terms. The facility is intended to allow the Company to close additional acquisitions and/or fund drilling capital expenditures on our existing properties. At September 30, 2014, this facility was drawn US$29.5 million.

In June 2014, the Company closed a non-brokered private placement of 5 million voting common shares at $1.30 per share for gross proceeds of $6.5 million. Proceeds from this offering were used to repay debt as well as to fund capital expenditures and certain of the acquisitions described above.

OUTLOOK

The Company is continuing with its business model of acquiring and developing strategic assets in the Williston Basin, North Dakota, with significant capital expenditures in the third quarter. Opportunities continue for organic growth through the Company's strategic alliance with Slawson Exploration Company Inc. The Company continually searches for and reviews potential acquisitions which fit within its strategic parameters. The Company has continued its drilling program and has 26 gross wells (2.2 net wells) in progress currently and we anticipate drilling activity throughout the remainder of the year and in 2015 on existing assets. Depending on the timing of completion of some of these new wells, production is anticipated to remain consistent until these new wells are brought online, contributing to increased production in the first and second quarter of 2015.

RESULTS OF OPERATIONS

Production

The following table summarizes daily gross Company interest production volumes for the relevant periods.

	Three months ended September 30,		Nine months ended September 30,	
	2014	**2013**	**2014**	**2013**
Crude oil and natural gas liquids (Bbl per day)	240	172	228	147
Natural gas (Mcf per day)	47	146	60	78
Total (Boe per day)	248	196	238	160

(1) "Bbl" refers to barrels.
(2) "Mcf" refers to thousand cubic feet.

Daily production for the nine months ended September 30, 2014 increased compared to the nine months ended September 30, 2013 primarily as a result of the acquisition of Stockyard Creek in August of 2013. Production from the Company's non-core assets in Ontario, Canada has decreased compared to the prior periods due to natural declines. During the third quarter, three new wells (0.3 net to the Company) were brought on production, which was offset by the shutting-in of a substantial portion of the Company's Stockyard Creek production to accommodate incremental infill drilling in that field. Drilling and completion of an additional 2.2 net wells is currently underway, which we anticipate will lead to increased production in the first and second quarter of 2015.

The following table presents the Company's relative production by country:

Production Ratio

	Three months ended September 30,		Nine months ended September 30,	
	2014	**2013**	**2014**	**2013**
United States	92%	85%	91%	81%
Canada	8%	15%	9%	19%

The increase in the relative amount of US production in 2014 is due to the Company's continued focus on executing its strategy of acquiring and developing assets in the Williston Basin in North Dakota.

Pricing

Realized prices	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Crude oil and natural gas liquids ($ per Bbl)	$ 93.27	$ 102.87	$ 96.61	$ 96.20
Natural gas ($ per Mcf)	5.29	5.59	8.36	5.17
Boe ($ per Boe)	$ 91.40	$ 94.28	$ 94.72	$ 90.93

Average benchmark prices				
Crude oil – West Texas Intermediate (WTI US$ per Bbl)	$ 97.73	$ 105.82	$ 99.86	$ 98.12
Natural gas – Henry Hub (US$ per Mcf)	3.96	4.01	4.59	3.69
Exchange rate (US$ /CDN$)	1.09	1.04	1.10	1.02

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 of the Company's realized crude price to the Canadian dollar equivalent of WTI during the nine months ended September 30, 2014 increased $9.35 relative to the nine months ended September 30, 2013. Higher benchmark prices and the weakness of the Canadian dollar resulted in higher net realized prices in the current reporting period. The third quarter realized oil price is lower than the same period in 2013 due primarily to lower WTI prices. The realized natural gas price is higher than the benchmark mainly due to regional pricing and the high heat rate of the Company's natural gas, which is sold prior to extracting natural gas liquids.

As at November 14, 2014, world oil prices have declined significantly from the average levels during the third quarter and will have a negative impact on realized prices for our oil production in the fourth quarter.

Royalties

	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Royalties (in thousands)	$ 442	$ 341	$ 1,362	$ 856
Royalties per Boe	$ 19.38	$ 18.87	$ 20.98	$ 19.60
Royalties as % of Revenue Per Boe	21.2%	20.0%	22.2%	21.6%

While the royalty rate remains stable, the royalties per Boe are slightly higher in 2014 due to the higher realized prices in the nine months ended September 30, 2014 compared to the same period in 2013.

Operating Costs and Production Taxes

	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Operating costs	$ 245	$ 173	$ 727	$ 544
Production taxes	179	89	461	162
Operating costs and production taxes (in thousands)	$ 424	$ 262	$1,188	$ 706
Operating costs per Boe	$ 10.74	$ 9.57	$ 11.20	$ 12.45
Production taxes per Boe	7.85	4.92	7.10	3.71
Operating costs and production taxes per Boe	$ 18.59	$ 14.49	$ 18.30	$ 16.16

Operating costs and production taxes are comprised of lease operating expenses, production taxes and transportation costs. Operating costs and production taxes for the three and nine months ended September 30, 2014 increased

$162,000 and $482,000 respectively compared to the corresponding periods in the prior year. The increase reflects the higher production tax rates due to expiring tax incentives and higher production volumes in the current period.

Operating costs

Currently, the Company operates in three main areas (two in the US and one in Canada). Each of these areas has different cost and production characteristics, which influence the operating cost per Boe. The Company's Canadian assets are mature and have been producing for several years. With the natural rate of decline and the fixed costs associated with the field, the costs per Boe increase over time. The Canadian assets only account for approximately 8% of current production and the related operating and production costs are not expected to influence the overall per Boe cost significantly in the future.

The Company has two main areas in the US: one is the Mondak area, which targets the upper Bakken shale formation; and the other, in North Dakota, targets the middle Bakken and Three Forks formations. Mondak has historically had higher operating costs per Boe due to high water cuts and single well operations. Operating costs per Boe increased for the three months ended September 30, 2014 compared to the same period in 2013 due to costs associated with the shut-in of existing producing wells in Stockyard Creek during offset and infill pad drilling. Operating costs per Boe decreased for the nine months ended September 30, 2014 over the prior period due to less production coming from our Mondak asset.

Production taxes and transportation costs

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 and in Montana, production taxes are 0.76% for the first 18 months of a well's production which then escalates to 9.3% thereafter. In previous years, there was a tax incentive in North Dakota for drilling certain new wells in the Melbby area, whereby the Company was not subject to the oil extraction tax for the first 60 months of production on several of its wells. For the three and nine months ended September 30, 2013, production taxes per Boe were lower due to the tax incentive for the oil extraction taxes in North Dakota along with Montana production making up a higher portion of total US production as compared to the current respective periods. The increase in the production taxes per Boe in the three and nine months ended September 30, 2014 are related to new wells subject to the full severance and oil production taxes.

Operating Netbacks

	Three months ended September 30,		Nine months ended September 30,	
($ per Boe)	**2014**	**2013**	**2014**	**2013**
Revenue	$ 91.40	$ 94.28	$ 94.72	$ 90.93
Royalties	(19.38)	(18.87)	(20.98)	(19.60)
Realized hedge (loss)	(1.14)	-	(0.82)	-
Operating costs	(10.74)	(9.57)	(11.20)	(12.45)
Production taxes	(7.85)	(4.92)	(7.10)	(3.71)
Operating netback	$ 52.29	$ 60.92	$ 54.62	$ 55.17
Operating netback prior to hedging	$ 53.43	$ 60.92	$ 55.44	$ 55.17
Operating netback prior to hedging, on a net of royalty basis	$ 67.85	$ 76.16	$ 71.24	$ 70.36

Operating netback per Boe, prior to hedging, increased during the nine months ended September 30, 2014 by $0.27 or 0.5% compared to the same period in the prior year. The higher operating netback can be attributed to higher realized prices, resulting from a weaker Canadian dollar, which was offset by the increase in royalties and production taxes. Operating netback in the quarter decreased $7.49 per Boe prior to hedging due to a decline in benchmark oil prices and higher operating costs and production taxes.

General and Administrative Expense

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
General and administrative expense (in thousands)	$ 627	$ 493	$ 1,851	$ 1,249

General and administrative expense ("G&A") increased approximately $134,000 and $602,000 during the three months and nine months ended September 30, 2014, respectively compared to the same periods in the prior year. This increase can be attributed to additional land acquisition and other personnel and increased legal and accounting fees associated with the Company's acquisitions during the period, which are required to be expensed for accounting purposes under IFRS.

Share-based Compensation

Share-based compensation expense reflects the value ascribed to stock options provided to employees and directors of the Company, and were calculated utilizing a fair value assessment methodology. The Company issued 275,000 stock options to employees in the nine months ended September 30, 2014. Share-based compensation was $419,000 for the nine months ended September 30, 2014 compared to $488,000 for the nine months ended September 30, 2013. This decrease is partially due to the vesting and the cancellation of certain stock options in late 2013.

Depletion and Depreciation Expense

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Depletion and depreciation expense (in thousands)	$ 540	$ 432	$ 1,449	$ 1,070
Depletion and depreciation per Boe	$ 23.67	$ 23.90	$ 22.32	$ 24.50

Depletion and depreciation expense increased during the three and nine months ended September 30, 2014 compared to the same periods in the prior year. The increase is related to increased production volumes and an increase in the depletable asset base associated with the acquisitions described elsewhere in this MD&A. The per Boe rate of depletion and depreciation expense year to date decreased as certain assets' book values have been reduced due to impairments recorded in 2013.

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. This evaluation for 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 cost basis is in excess of the estimated recoverable value, then the Company will record an impairment expense related to the CGU. During the nine months ended September 30, 2014 management determined that there were no impairment indicators. During the nine months ended September 30, 2013, management determined that there were impairment indicators which resulted in an impairment of property, plant and equipment for that period of $3.3 million.

Exploration and evaluation ("E&E") assets are evaluated for impairment when facts and circumstances of impairment exist and also at the time that the assets are transferred to D&P assets. Factors that may indicate an impairment of assets include, but are not limited to, the rights to explore in an area have expired or will expire in the near future without renewal, there are no future plans for additional exploration or evaluation, or a decision to discontinue exploration and evaluation in an area was made because of the absence of commercial reserves and sufficient data indicates the book value of the assets will not be recovered from future production. For the nine months ended September 30, 2014, management determined that there were no impairment indicators. For the nine months ended

September 30, 2013, the Company recorded impairment expense of $14.0 million against its exploration and evaluation assets. The entire impairment expense for that period is related to acreage and wells in the Mondak area.

Financial Derivative Instruments

The Company's commodity derivative contracts as at June 30, 2014 were settled with the counterparty during the three month period ended September 30, 2014 with a net payment of $19,000. As at September 30, 2014, the Company has no outstanding derivative contracts.

Finance Expense

Under IFRS, non-cash accretion expense related to decommissioning obligations is presented as part of finance expense.

Finance expense for the nine months ending September 30, 2014 reflected interest for the Company's senior loans, note payable and subordinated loan, including the amortization of certain loan origination fees. Finance expense for the three and nine months ended September 30, 2014 increased over the three and nine months ended September 30, 2013 due to financing the acquisitions and capital expenditures described herein primarily with debt. As at September 30, 2014, the Company has increased its debt level to fund the acquisitions described above and capital expenditures, and as a result, finance expense will increase for the remainder of the year.

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, as this is the primary economic environment in which the subsidiary operates. The US subsidiary has a US dollar functional currency. The assets, liabilities and results of operations of the Company's US subsidiary is 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, 2014, this was a gain due to the strengthening of the US dollar against the Canadian dollar during the period.

Share Capital

	Three months ended September 30,		Nine months ended September 30,	
	2014	**2013**	**2014**	**2013**
Weighted average common shares outstanding:				
Basic and diluted	34,207,552	29,007,552	31,393,633	28,945,706
Outstanding securities:				
Common shares, voting and non-voting			34,207,552	29,007,552
Stock options			2,275,205	1,983,014
Warrants			-	15,674,996

The weighted average exercise price of stock options outstanding as at September 30, 2014 is $1.16. As at November 14, 2014, 34,207,552 common shares and 2,275,205 stock options are outstanding.

Capital Expenditures

The following table represents capital expenditures for the nine months ended September 30, 2014:

(in thousands)	Property, Plant and Equipment	Exploration and Evaluation Assets	Total
Acquisitions	$ 30,659	$ -	$ 30,659
Capital expenditures			
Drilling and completion	15,772	-	15,772
Other	19	59	78
Total capital expenditures	$ 46,450	$ 59	$ 46,509

During the nine months ended September 30, 2014, the Company completed 11 gross wells (1.0 net well) and spud 20 gross wells (2.0 net wells) which are drilling or awaiting completion as at September 30, 2014.

The Company has no commitments to make additional capital expenditures. The Company's reserve report prepared by its independent engineers as at June 30, 2014 included estimated future development cost of US$57.1 million. With the new senior loan and enhanced capacity under the subordinated loan facility described elsewhere in this MD&A, the Company believes it has sufficient liquidity to meet its anticipated capital expenditures for the next 12 months.

Liquidity and Capital Resources

Capital expenditures for acquisitions and drilling and completion activities for the nine months ended September 30, 2014, as described above, were financed through the Company's senior loans, subordinated loan facility, and equity financing as described below.

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/or property acquisitions. The Company will manage its borrowings in relation to its credit capacity and its ability to generate future operating cash flows.

The Company manages the pace of its capital spending related to drilling operations by continuously monitoring 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. 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 office 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.

During the third quarter, the Company entered into a new revolving credit facility with a renewal date of July 10, 2015. This facility is referred to as the senior loan under current liabilities in the statements of financial position. The initial borrowing base is US$10.0 million secured by all of the assets of the Company. 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 facility is subject to certain financial and non-financial covenants, which the Company was in full compliance with at September 30, 2014. This facility was drawn by approximately US$3.0 million at September 30, 2014. The next review to be performed by the bank will be completed based upon the receipt of an updated independent reserves report as at December 31, 2014. Management anticipates that the yearend reserve report will facilitate an increase in the borrowing base and the capacity of the senior credit facility.

In 2014, the Company entered into a secured, subordinated revolving credit facility with its two largest shareholders

providing a US$30.0 million revolving line of credit with a maturity date of January 1, 2016. The facility is intended to allow the Company to close additional acquisitions and/or fund drilling 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 Company has drawn approximately US$29.5 million under the subordinated loan as at September 30, 2014. Recently, the Company extended the capacity of the facility to US$50.0 million. The purpose of the subordinated loan is to provide additional financial flexibility to the Company during its initial period of growth. The terms of the subordinated loan are similar to those which management believes could be negotiated with third parties.

In June 2014, the Company closed a private placement of 5 million common voting shares at a price of $1.30 per share for gross proceeds of up to $6.5 million. Approximately 3.4 million shares were purchased by directors and officers of the Company. Proceeds from this offering were used to repay debt as well as to fund capital expenditures and certain of the acquisitions described above.

The incremental liquidity provided by proceeds from the private placement and the extension of the subordinated loan, in both amount and maturity date, will assist the Company with meeting its capital needs in the upcoming quarters, including financing the working capital deficit of $11.2 million as at September 30, 2014. 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 with its recently updated reserve report and future drilling activities, it will be able to support a larger borrowing base under its senior loan facility in the future. Similarly, should the Company require the subordinated loan beyond its current January 1, 2016 maturity date, it anticipates an ability to extend the term of that facility.

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, 2014 and the expected timing of the settlement of these obligations.

(in thousands)	Total	Less than 1 year	1-2 years	3-5 years	Thereafter
Accounts payable and accrued liabilities	$ 12,066	$ 12,066	$ -	$ -	$ -
Operating leases (office rent)	305	110	102	93	-
Subordinated loan [(1)]	33,011	-	33,011	-	-
Senior loan	3,265	3,265	-	-	-
Total	$ 48,647	$ 15,441	$ 33,113	$ 93	$ -

[(1)]The amount differs from that presented on the statement of financial position due the unamortized portion of loan origination fees.

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 outstanding two letters of credit in favor of the energy regulators in its operating areas in the amount of $58,000 and US$75,000. As security for these letter of credit, the Company has set aside these amounts in cash at the financial institutions that issued the letters of credit.

Related Party Transactions

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

The Company's subordinated loan is provided by two significant shareholders of the Company, one of whom is also a director and the CEO. The terms of the subordinated loan are similar to those which management and the Board believe could be negotiated with third parties. The Company paid origination fees of US$0.8 million and interest expense of US$1.2 million in the nine months ended September 30, 2014.

Certain of the Company's directors and officers participated in the Company's private placement in the amount of 3.4 million shares of the 5.0 million issued in aggregate.

Summary of Quarterly Results

Three month period ended (in thousands):	9/30/2014	6/30/2014	3/31/2014	12/31/2013	9/30/2013	06/30/2013	03/31/2013	12/31/2012
Oil and natural gas sales, net of royalties	$ 1,643	$ 2,089	$ 1,054	$ 1,067	$ 1,363	$ 1,038	$ 715	$ 680
Net loss	(892)	(578)	(554)	(2,597)	(87)	(605)	(17,371)	(1,548)
Net loss per share –Basic and diluted	$(0.03)	$(0.02)	$(0.02)	$ (0.09)	$ (0.00)	$ (0.02)	$ (0.60)	$ (0.05)

Factors that influenced quarterly variations

Quarter over quarter fluctuations are attributable to the items discussed below. In the quarter ended September 30, 2014, revenue decreased over the prior quarter due to three new wells being completed and put on production during the quarter which was 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 increased over the prior quarter due mainly to an impairment expense recognized of $1.9 million and an increase in general and administrative expenses.

The Company acquired several projects in October 2012, May 2013 and August 2013 and participated in drilling programs which have increased production and revenue over the quarters.

The initial wells drilled in the Mondak project did not meet expected production rates. As a result, the Company recognized approximately $16.7 million of impairment expense in the quarter ended March 31, 2013, which is the

primary cause for the ($0.60) net loss per share. An additional $0.5 million of impairment expense was recognized in the quarter ended June 30, 2013 in Mondak.

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 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, depreciation 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.

Financial derivatives

By their very nature, the estimated fair value of financial derivative instruments resulting in financial derivative assets and liabilities in the statements of financial position and the recognition of unrealized gain (loss) on financial derivatives in the statements of operations are subject to measurement uncertainty as they are derived from estimates of future commodity prices during the remaining term of the respective contracts.

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

On January 1, 2014, the Company adopted amendments to "Offsetting Financial Assets and Financial Liabilities" addressed within IAS 32 – "Financial Instruments: Presentation", which provides guidance regarding when it is appropriate and permissible for an entity to disclose offsetting financial assets and financial liabilities on a net basis. The Company also adopted IFRIC 21 – "Levies", which establishes guidelines for the recognition and accounting treatment of a liability relating to a levy imposed by a government. The adoption of these standards had no impact on the amounts recorded in the financial statements as at January 1, 2014 or on the comparative periods.

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.

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 the 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 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; currently, all of its US properties are non-operated. Because it does not 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 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 and 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;
- 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 of new wells to meet gas capture goals within ninety days of commencement of production. 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.

PetroShale, along with its operators, is committed to minimizing the environmental impact from its operations through an environmental program which includes stakeholder communication, resource conservation and site restoration.

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

PetroShale mitigates these risks as follows:

- PetroShale's operators 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 the operator, 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.

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.