PetroShale

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Management's Discussion & Analysis

For the year ended December 31, 2014, the six months ended December 31, 2013
and the year ended June 30, 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 March 27, 2015. This MD&A reports on the consolidated financial position and the consolidated results of operations of PetroShale for the year ended December 31, 2014, the six months ended December 31, 2013, and the year ended June 30, 2013 and should be read in conjunction with PetroShale's consolidated financial statements as at and for the year ended December 31, 2014. 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 year ended December 31, 2014 has been presented with comparative information for the six months ended December 30, 2013 and the year ended June 30, 2013.

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, 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 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 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 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 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.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
FINANCIAL					
Oil and natural gas revenue	$3,116	$1,361	$9,264	$3,065	$3,712
Funds flow from (used in) operations [1]	($193)	($227)	$39	$264	$207
Net loss	($3,030)	($2,597)	($5,054)	($2,684)	($21,129)
Per share - basic and diluted	($0.09)	($0.09)	($0.16)	($0.09)	($0.73)
EBITDA [1]	$970	($116)	$2,647	$501	$737
Capital expenditures	$17,952	$2,248	$64,461	$3,465	$9,518
Net debt and working capital deficit			($64,018)	($3,000)	($662)
Common shares outstanding					
Weighted average - basic and diluted	34,207,552	29,007,552	32,102,895	29,007,552	28,893,744
OPERATING					
Number of Days	92	92	365	184	365
Daily production					
Crude oil (Bbls)	489	158	294	165	118
Natural gas (Mcf)	179	101	90	124	29
Barrels of oil equivalent (Boe)	519	175	309	185	122
Average realized price [2]					
Crude oil ($/Bbl)	$66.73	$89.58	$84.08	$96.52	$85.18
Natural gas ($/Mcf)	$6.88	$8.20	$7.62	$7.48	$4.79
Netback per Boe ($) [1]					
Revenue	$65.27	$84.76	$82.21	$89.80	$83.02
Royalties	($13.98)	($18.31)	($18.01)	($18.61)	($18.59)
Realized (gain) loss on hedge	$ -	$0.50	($0.47)	$0.23	$ -
Operating costs and production taxes	($13.04)	($14.38)	($16.07)	($14.44)	($16.75)
Operating netback	$38.25	$52.57	$47.66	$56.98	$47.68
Operating netback prior to hedging	$38.25	$52.07	$48.13	$56.75	$47.68
Operating netback prior to hedging, on a net of royalty basis	$48.76	$66.41	$61.68	$71.62	$61.44

[1] *Non-IFRS measure - See page 2 and the tables on pages 22 and 23.*

[2] *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.

2014 SIGNIFICANT EVENTS

Oil and Gas Acquisitions and Development

During the year ended December 31, 2014, the Company purchased 2,442 net acres of oil and gas leases and producing properties with approximately 140 Boe per day of production. All of the transactions were in our core areas within North Dakota. The Company paid US$32.8 million to complete these transactions which were funded by a combination of cash, credit facilities, and the issuance of 5,200,000 common shares. In addition, the Company participated in drilling 43 gross (3.3 net) wells in 2014 for a total capital expenditure of US$25.0 million; of these 43 wells, 17 gross (2.2 net) wells were either tested or brought on production during 2014. Several of these wells were just flowing back at year end or in early January 2015 and had yet to have significant sales as of December 31, 2014. Some of these wells will be brought on production once associated gas is tied in to sales infrastructure in the second quarter of 2015.

For the three months ended December 31, 2014 the Company completed four transactions for US$4.8 million including undeveloped acreage and the producing properties noted above.

Reserves Update

The Company obtained a US asset reserves report from its independent engineers, Netherland, Sewell, & Associates, as at December 31, 2014. Reflecting activity to that date as described above, all reserve categories were enhanced with total proved plus probable US reserves increasing from 656 Mboe as at December 31, 2013 (Net present value discounted at 10% ("PV10") –US$12.1 million) to 10,260 Mboe as at December 31, 2014 (PV10- US$142 million).

Despite the significant decline in oil prices at year end and the reduction in forecast prices used to calculate ending reserve values, the Company avoided an impairment on its core US assets due to the strong reserve additions booked in 2014.

Gross Company Interest Reserves (US$)

	December 31, 2014 MBOE	December 31, 2013 MBOE	December 31, 2014 PV10% ($M)*	December 31, 2013 PV10% ($M)*
Proved Developed Producing	1,962	299	$ 44,539	$ 7,330
Total Proved	6,600	508	$ 102,120	$ 10,700
Probable	3,660	148	$ 39,920	$ 1,397
Total Proved Plus Probable	10,260	656	$ 142,040	$ 12,097
Liquids %	86%	85%		

*The PV10 values reflect price decks utilized by the independent engineers in accordance with NI 51-101 which assumes forecast pricing as further detailed in the Company's December 31, 2014 consolidated financial statements, Note 8.

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 as at December 31, 2014. The new facility is due on demand, but on the renewal date, 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. The bank recently increased the borrowing base to US$15.5 million and extended the renewal date to March 24, 2016. The next borrowing base review will be performed by the bank following the receipt of an updated reserve report as of June 30, 2015, at which point the Company anticipates a further borrowing base increase as production from new wells commence and cash flow increases. As at December 31, 2014, the Company was approximately fully drawn on the 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 December 31, 2016 on existing terms. The facility is intended to allow the Company to close additional acquisitions and/or fund drilling and well completion expenditures on our existing properties. At December 31, 2014, this facility was drawn US$32.3 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.

2015 OUTLOOK

Impact of Low Oil Price

The current world oil price environment has had a significant impact on PetroShale and all oil and gas companies in the Williston Basin. With WTI averaging less than $50 per barrel in January and February 2015, our operating netback was negatively impacted but still in excess of $20 per barrel because our properties are situated in the more economic areas of North Dakota. Not all North Dakota Bakken production is economic. As a result, we have witnessed a dramatic reduction in capital spending plans for 2015 by the majority of operators in the basin. We believe this will result in lower drilling expenditures in 2015 on PetroShale's properties than would otherwise have been the case.

Partially offsetting the impact of the low oil prices, a tax incentive was implemented effective March 1, 2015 reducing North Dakota's extraction tax by 4% of revenue for wells completed in North Dakota after March 1, 2015 and before July 1, 2015. This rate reduction is limited to the lesser of the first 75,000 Bbls of oil and 18 months of oil production, and is eliminated once WTI recovers above US$70 per barrel. We expect 1.2 of our net wells to benefit from this abatement.

Q1 2015 Activity

PetroShale has a working interest in 19 gross (0.5 net) wells currently being drilled or completed. In addition, 5 gross (1.3 net) wells were completed and flowed back in late 2014 and early 2015. These wells are currently shut-in due to new flaring regulations waiting for gas gathering lines to be completed. We anticipate these wells to be placed into full production in the second quarter of 2015. Activity is expected to slow down significantly in Q2 and Q3 with operators electing to defer drilling and completions activity.

PetroShale considers the price environment to be an opportunity to continue its disciplined strategy of acquiring and developing leases within our core area in the Williston Basin.

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 December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Crude oil (Bbl per day)	489	158	294	165	118
Natural gas (Mcf per day)	179	101	90	124	29
Total (Boe per day)	519	175	309	185	122
Liquids % of Production	94%	90%	95%	89%	96%

Daily production for the three months ended December 31, 2014 increased compared to the prior period ended December 31, 2013 primarily as a result of newly completed wells being brought online. Production from the Company's non-core assets in Ontario, Canada has decreased compared to the prior periods due to natural declines. During the fourth quarter, 6 gross (1.2 net) new wells were brought on production. Three gross (0.8 net) of these wells were subsequently shut in awaiting tie-in to gas sales infrastructure which is expected to be completed in the second quarter of 2015. The Company also acquired producing properties late in the fourth quarter of 2014 which had a small impact on production in the quarter but will have a greater impact in 2015. A substantial portion of the Company's Stockyard Creek production remained shut-in during the fourth quarter to accommodate incremental infill drilling and well completions in that field. This production was brought back online in the first quarter of 2015 at restricted rates because of low oil prices, and along with anticipated new production from wells completed in the first and second quarters of 2015, management is anticipating a significant increase in production in 2015.

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

Production Ratio

	Three months ended December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
United States	94%	83%	92%	84%	73%
Canada	6%	17%	8%	16%	27%

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

Average benchmark prices	Three months ended December 31, 2014	2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Crude oil – WTI (US$ per Bbl)	$ 71.20	$ 97.45	$ 87.70	$ 101.64	$ 92.27
Natural gas – HH (US$ per Mcf)	3.79	4.25	4.39	3.91	3.43
Exchange rate (US$ /CAD$)	$ 1.14	$ 1.05	$ 1.11	$ 1.04	$ 1.00
Realized prices - Total production (CAD)					
Crude oil ($ per Bbl)	$ 66.73	$ 89.58	$ 84.08	$ 96.52	$ 85.18
Natural gas ($ per Mcf)	6.88	8.20	7.62	7.48	4.79
Per Boe	$ 65.27	$ 84.76	$ 82.21	$ 89.80	$ 83.02
Realized prices - US production (USD)					
Crude oil ($ per Bbl)	$ 58.92	$ 83.41	$ 75.25	$ 89.48	$ 77.25
Natural gas ($ per Mcf)	6.32	7.67	7.00	7.32	4.02
Per Boe	$ 57.69	$ 79.21	$ 73.57	$ 83.68	$ 83.68

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 December 31, 2014 was US$12.28, which is improved from $14.04 in the same period in 2013. Lower benchmark prices, slightly offset by the weakness of the Canadian dollar, resulted in lower net realized prices in the current reporting period in Canadian dollars. 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 generally sold prior to extracting natural gas liquids.

Towards the end of 2014 and during the first quarter of 2015, world oil prices have declined significantly from the average levels during the year ended December 31, 2014 and will have a negative impact on realized prices for our oil production in 2015.

Royalties

	Three months ended December 31, 2014	2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Royalties (in thousands)	$ 668	$ 294	$ 2,030	$ 635	$ 831
Royalties per Boe	$ 13.98	$ 18.31	$ 18.01	$ 18.61	$ 18.59
Royalties as % of Revenue	21.4%	21.6%	21.9%	20.7%	22.4%

The royalty rate has remained stable, however, the royalties per Boe are lower in the fourth quarter of 2014 due to the lower realized prices in the period. Management anticipates the royalty per Boe will decline in 2015 with realized commodity prices, but the % of revenue to remain consistent.

Operating Costs and Production Taxes

	Three months ended December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Operating costs	$ 384	$ 164	$ 1,111	$ 337	$ 651
Production taxes	239	67	700	156	98
Operating costs and production taxes (in thousands)	$ 623	$ 231	$ 1,811	$ 493	$ 749
Operating costs per Boe	$ 8.04	$ 10.21	$ 9.86	$ 9.87	$ 14.56
Production taxes per Boe	5.00	4.17	6.21	4.57	2.19
Operating costs and production taxes per Boe	$ 13.04	$ 14.38	$ 16.07	$ 14.44	$ 16.75

Operating costs and production taxes are comprised of lease operating expenses, production taxes and transportation costs.

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 production decline and the fixed costs associated with the field, the costs per Boe increase over time. The Canadian assets only account for approximately 6% 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 decreased for the three months and year ended December 31, 2014 compared to the three months ended December 31, 2013 and year ended June 30, 2013 due to a larger portion of the production coming from our core North Dakota assets which have lower average operating expenses per Boe. Total operating cost dollars have increased period over period consistent with increasing production volumes.

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. 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 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 periods ended December 31, 2014, production taxes per Boe were higher than the corresponding periods due to the increased proportion of total production from the US and the expiring tax incentives in the Melbby and Mondak areas.

Operating Netback

($ per Boe)	Three months ended December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Revenue	$ 65.27	$ 84.76	$ 82.21	$ 89.80	$ 83.02
Royalties	(13.98)	(18.31)	(18.01)	(18.61)	(18.59)
Realized hedge gain (loss)	-	0.50	(0.47)	0.23	-
Operating costs	(8.04)	(10.21)	(9.86)	(9.87)	(14.56)
Production taxes	(5.00)	(4.17)	(6.21)	(4.57)	(2.19)
Operating netback	$ 38.25	$ 52.57	$ 47.66	$ 56.98	$ 47.68
Operating netback prior to hedging	$ 38.25	$ 52.07	$ 48.13	$ 56.75	$ 47.68
Operating netback prior to hedging, on a net of royalty basis	$ 48.76	$ 66.41	$ 61.68	$ 71.62	$ 61.44

Operating netback per Boe, prior to hedging, decreased during the periods ended December 31, 2014 compared to the prior periods ending December 31, 2013 primarily due to the decline in world oil prices in the fourth quarter of 2014, which was slightly offset by the corresponding reduction in royalty expense.

General and Administrative Expense

	Three months ended December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
General and administrative expense (in thousands)	$ 855	$ 969	$ 2,706	$ 1,461	$ 1,395

General and administrative expense ("G&A") decreased $114,000 during the three months ended December 31, 2014, compared to the same period in the prior period due to a settlement payment to the former CEO in 2013. The increase in total G&A for the year ended December 31, 2014 compared to the six months ended December 31, 2013 is a result of a longer reporting period. The general increase in G&A compared to the year ended June 30, 2013 is due to an increase in land acquisition and other personnel, as well as increased legal and other costs associated with the Company's acquisition strategy.

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 275,000 stock options to employees in the year ended December 31, 2014. Share-based compensation was $524,000 for the year ended December 31, 2014 compared to $179,000 for the six months ended December 31, 2013. This increase was partially due to the completion of vesting periods and the cancellation of certain stock options in late 2013 as well as the longer reporting period in 2014.

Depletion and Depreciation Expense

	Three months ended December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Depletion and depreciation expense (in thousands)	$ 958	$ 401	$ 2,407	$ 835	$ 1,063
Depletion and depreciation per Boe	$ 20.05	$ 24.97	$ 21.36	$ 24.47	$ 23.78

Depletion and depreciation expense increased during the three months and year ended December 31, 2014 compared to the three months and six months ended December 31, 2013. The increase is primarily related to increased production volumes associated with the acquisitions described elsewhere in this MD&A.

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 carrying amount is in excess of the estimated recoverable value, then the Company will record an impairment expense related to the CGU. During the three months ended December 31, 2014 management determined that there were impairment indicators arising from the significant decline in world oil prices. As a result of performing an impairment test, it was determined that the carrying amount of two of the Company's CGUs was less than its VIU, based on the independent reserve engineer report. During the three months ended December 31, 2014, an impairment charge for property, plant and equipment of $906,000 was recorded to reduce the carrying values of these CGUs to their determined value in use. During the six months ended December 31, 2013, and year ended June 30, 2013, management determined that there were impairment indicators which resulted in an impairment of property, plant and equipment for those periods of $0.3 million and $3.7 million respectively.

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 E&E 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 three months ended December 31, 2014, management determined that there were impairment indicators. As a result of reviewing its plans for development and assessing the commercial feasibility of its E&E assets, the Company fully impaired its remaining E&E assets, resulting in an impairment charge of $0.7 million during the three months ended December 31, 2014. During the six months ended December 31, 2013 and the year ended June 30, 2013, the Company recorded impairment expense of $1.7 million and $15.6 million respectively against its exploration and evaluation assets.

Financial Derivative Instruments

The Company's commodity derivative contracts were settled with the counterparty during the year ended December 31, 2014 with a net payment to the counterparty of $19,000. As at December 31, 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 year ended December 31, 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 months and year ended December 31, 2014 increased over the three and six months ended December 31, 2013 due to financing the acquisitions and capital expenditures described herein primarily with debt. As at December 31, 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 in 2015.

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 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 December 31, 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 December 31, 2014	Three months ended December 31, 2013	Year ended December 31, 2014	Six months ended December 31, 2013	Year ended June 30, 2013
Weighted average common shares outstanding:					
Basic and diluted	34,207,552	29,007,552	32,102,895	29,007,552	28,893,744
Outstanding securities:					
Common shares, voting and non-voting			34,207,552	29,007,552	29,007,552
Stock options			2,275,205	2,000,205	1,884,751
Warrants			-	-	15,674,996

As at March 27, 2015, 34,207,552 common shares and 2,295,205 stock options are outstanding, including the issuance of 20,000 options in January 2015.

The following stock options are outstanding as at December 31, 2014:

Stock Options

Exercise Prices	Weighted Average Remaining Contractual Term	Number of Outstanding Options	Number of Options Exercisable	Weighted Average Exercise Price
$0.70	3.90	943,264	314,419	$0.70
$1.40	4.19	275,000	-	$1.40
$1.50	2.21	1,056,941	1,056,941	$1.50
	3.15	2,275,205	1,371,360	$1.16

Capital Expenditures

The following table represents capital expenditures for the year ended December 31, 2014:

(in thousands)	Property, Plant and Equipment	Exploration and Evaluation Assets	Total
Acquisitions	$ 36,248	$ -	$ 36,248
Capital expenditures			
Drilling and completion	28,047	-	28,047
Other	30	136	166
Total capital expenditures	$ 64,325	$ 136	$ 64,461

During the year ended December 31, 2014, the Company participated in 43 gross (3.3 net) wells. Acquisition and drilling and completions expenditures during 2014 were significantly higher than the prior periods as the Company executed on its strategy.

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 includes estimated future development costs of US$64.4 million for proved reserves and US$118.7 million for proved and probable reserves. Of this total, US$3.7 million is scheduled for 2015 in the independent reserve report. 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.

Land Holdings

As at December 31,	2014		2013		% Change	
Acres	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Held by Production	44,136	2,259	17,118	937	158%	141%
Not Held by Production	58,020	2,149	75,167	2,082	-23%	3%
Total	102,156	4,408	92,285	3,019	11%	46%
Average Working Interest (%)		4.3%		3.3%		

As of December 31, 2014, the Company held a total of 4,408 net acres of land, which represented an increase of 46% from the 3,019 it held at the end of 2013. The net acreage held by production in 2013, which was 937 acres, increased by 141% to 2,259 acres. The ratio of acreage held by production to total acreage (net) increased from 31% to 51% as at December 31, 2014.

Liquidity and Capital Resources

Capital expenditures for acquisitions and drilling and completion activities for the year ended December 31, 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 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 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. Management anticipates that the operators of its properties are also in the process of evaluating their capital programs in light of current commodity prices and drilling activity is and 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.

During the year, the Company entered into a new senior revolving credit facility with a renewal date of July 23, 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 and the loan is 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 December 31, 2014. 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. This facility was approximately fully drawn at December 31, 2014. The bank recently increased the borrowing base to US$15.5 million and extended the renewal date to March 24, 2016. The next borrowing base review will be performed by the bank based upon the receipt of an updated reserve report as of June 30, 2015, at which point the Company anticipates a further borrowing base increase as production from new wells commence and cash flow increases.

In 2014, the Company entered into a secured, subordinated revolving credit facility with its two largest shareholders. The maturity date on this facility was recently extended to December 31, 2016. The facility has a US$50.0 million capacity and is intended to allow the Company to close additional 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 Company has drawn approximately US$32.3 million under the subordinated loan as at December 31, 2014 and as at March 27, 2015 was approximately fully drawn. 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.

Management anticipates that, absent an equity offering, sustained low oil prices may result in a breach of the consolidated cash flow to interest expense covenant under the senior loan described above during the latter half of 2015. Management has obtained a waiver from this covenant from the senior lender 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. Management has notified the subordinated lenders that interest payments will be deferred commencing April 1, 2015. 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 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 subordinated loan as at December 31, 2014 and the increased capacity under the senior loan will assist the Company with meeting its capital needs in the upcoming quarters, including financing the working capital deficit of $16.1 million as at December 31, 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 drilling activities will support a larger borrowing base under its senior loan facility in the future as its significant proven undeveloped and probable reserves are developed. The Company also anticipates an increase in operating cash flows as new production is brought online in the first half of 2015.

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 December 31, 2014 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	$ 19,329	$ 19,329	$ -	$ -	$ -
Operating leases (office rent)	287	113	104	70	-
Subordinated loan (1)	46,423	4,493	41,930	-	-
Senior loan(2)	11,617	11,617	-	-	-
Total	$ 77,656	$ 35,552	$ 42,034	$ 70	$ -

(1)The amount differs from that presented on the statement of financial position due the unamortized portion of loan origination fees. Includes interest expense at the fixed rate of 12.0% as at December 31, 2014. The impact of a deferral of interest payments as described above has not been reflected here.

(2)Includes interest expense at the rate of 4.0% being the rate applicable at December 31, 2014.

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.

Compensation of key management personnel

Key management personnel include the Chief Executive Officer of the Company, the President of PetroShale (US), Inc., the Chief Financial Officer and the directors and other officers of the Company.

(in thousands)	Year Ended December 31, 2014	Six Months Ended December 31, 2013	Year Ended June 30, 2013
Salaries and other short-term benefits	$ 287	$ 365	$ 37
Consulting fees	330	251	488
Share-based compensation	422	179	893
	$ 1,039	$ 795	$ 1,418

A payment of USD$250,000 was made to the former President and Chief Executive Officer with respect to his cessation of employment during the six month period ended December 31, 2013.

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$1.25 million and amortized

US$0.5 million of that to finance expense in the year ended December 31, 2014.

Certain of the Company's directors and officers participated in the Company's June 2014 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):	12/31/2014	9/30/2014	6/30/2014	3/31/2014	12/31/2013	9/30/2013	6/30/2013	3/31/2013
Oil and natural gas sales, net of royalties	$ 2,448	$ 1,643	$ 2,089	$ 1,054	$ 1,067	$ 1,363	$ 1,038	$ 715
Net loss	(3,030)	(892)	(578)	(554)	(2,597)	(87)	(605)	(17,371)
Net loss per share –Basic and diluted	$ (0.09)	$ (0.03)	$ (0.02)	$ (0.02)	$ (0.09)	$ (0.00)	$ (0.02)	$ (0.60)

Factors that influenced quarterly variations

Quarter over quarter fluctuations are attributable to the items discussed below. For the quarter ended December 31, 2014, net revenue increased due to a significant increase in production, offset by a reduction in oil prices. The net loss in this quarter reflects the impairments discussed herein as well as the finance expense associated with the Company's increased debt. 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 increased over the prior quarter due mainly to an impairment expense recognized of $1.9 million and an increase in general and administrative expenses.

Generally, the Company acquired several projects in 2012, 2013 and 2014 and participated in drilling programs which have increased production and revenue over that period of time.

The initial wells drilled in the Mondak project in 2012 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.

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.

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.

IFRS 11 – "Accounting for Acquisitions of Interests in Joint Operations" is being amended. 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, 2017 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; 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 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.

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 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 limited resources. Due to its limited number of accounting and finance personnel, 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 statements.

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:

($ thousand)	**Year Ended December 31, 2014**	**Six Months Ended December 31, 2013**	**Year Ended June 30, 2013**
Cash flow from (used in) operating activities	$ (847)	$ 91	$ 292
Decommissioning expenditures	84	-	-
Change in non-cash working capital	802	173	(85)
Funds flow from operations	$ 39	$ 264	$ 207

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

($ thousands)	Three Months Ended December 31, 2014	Three Months Ended December 31, 2013	Year Ended December 31, 2014	Six Months Ended December 31, 2013	Year Ended June 30, 2013
Net loss	$ (3,030)	$ (2,597)	$ (5,054)	$ (2,684)	$ (21,129)
Add back:					
Finance expense	1,351	104	3,184	224	187
Depletion and depreciation	958	403	2,407	835	1,063
Foreign exchange loss	-	1	-	-	349
Impairment of exploration and evaluation assets	680	1,653	680	1,653	15,625
Impairment of property, plant and equipment	906	294	906	294	3,749
Share-based compensation	105	26	524	179	893
EBITDA	$ 970	$ (116)	$ 2,647	$ 501	$ 737

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.