PetroShale

Calgary • Denver

Management's Discussion and Analysis & Interim Consolidated Financial Statements

As at September 30, 2021 and for the three and nine months ended September 30, 2021 and 2020

Table of Contents

Management's Discussion and Analysis

This Management's Discussion and Analysis (the "MD&A") has been prepared by management and was reviewed and approved by the Board of Directors of PetroShale Inc. ("PetroShale" or the "Company") on November 19, 2021. This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements as at September 30, 2021 and for the three and nine months ended September 30, 2021 and 2020, and the audited consolidated financial statements as at and for the years ended December 31, 2020 and 2019. The reader should be aware that the operating results discussed below may not be indicative of future performance.

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

Frequently Used Terms:

Term	**Description**
Bbl(s)	Barrel(s)
Boe	Barrel(s) of oil equivalent
Bbls/d	Barrels per day
Boepd	Barrels of oil equivalent per day
HH	Henry Hub, reference price paid in US$ for natural gas deliveries
Mcf	Thousand cubic feet
Mmbtu	Million British Thermal Units
Mmbtu/d	Million British Thermal Units per day
NGLs	Natural gas liquids
WTI	West Texas Intermediate, reference price paid in US$ for crude oil of standard grade

Barrel of Oil Equivalent Advisory

Where amounts are expressed on a Boe basis, natural gas volumes have been converted to Boe using a ratio of 6,000 cubic feet of natural gas to one barrel of oil (6 Mcf:1 Bbl). This Boe conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The value ratio between the commodities, based on the price of crude oil compared to natural gas, could be significantly different from the energy equivalency of 6 Mcf: 1 Bbl, and therefore utilizing this conversion ratio may be misleading as an indication of value.

Presentation of Volumes

The Company's reserves have been categorized as Tight Oil, Shale Gas, and Natural Gas Liquids pursuant to National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Production volumes and per Boe calculations are presented on a gross working interest basis, before royalty interests, unless otherwise stated.

Functional and Presentation Currency

Amounts in this MD&A are in Canadian dollars, unless otherwise stated, 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 this subsidiary operates. The US subsidiary has a US dollar functional currency. In translating the financial results from US dollars to Canadian dollars, the Company uses the following method: assets and liabilities are translated at the exchange rate in effect as at the date of the consolidated balance sheet; revenues and expenses are translated at the rate effective at the time of the transaction or the average rate for the period; and changes in shareholders' equity are translated at the rate effective at the time of the transaction. Unrealized gains and losses resulting from the translation to the Canadian dollar presentation currency are included in other comprehensive income.

Non-IFRS Measurements and Changes in Accounting Policies

This MD&A contains the terms "*operating netback*," "*operating netback prior to hedging*," "*net debt*," and "*adjusted EBITDA*" which are not defined by IFRS and therefore may not be comparable to performance measures presented by others.

Operating netback represents petroleum and natural gas revenue, plus or minus any realized gain or loss on financial derivatives, less royalties, lease operating costs, workover expense, production taxes and transportation expense. The operating netback is then divided by the working interest production volumes to derive the operating netback on a per Boe basis.

Operating netback prior to hedging represents operating netback prior to any realized gain or loss on financial derivatives.

Net debt represents total liabilities, excluding decommissioning obligation, deferred income tax liability, lease liability and financial derivative liability, less current assets, excluding financial derivative assets.

Adjusted EBITDA represents cash flow provided by operating activities prior to changes in non-cash working capital.

The Company believes that adjusted EBITDA provides useful information to the reader in that it measures the Company's ability to generate funds to service its debt and other obligations and to fund its operations, without the impact of changes in non-cash working capital which can vary based solely on timing of settlement of accounts receivable and accounts payable. Management believes that in addition to net income (loss) and cash flow provided by operating activities, operating netback and adjusted EBITDA are useful supplemental measures as they assist in the determination of the Company's operating performance, leverage, and liquidity. Operating netback is commonly used by investors to assess performance of oil and gas properties and the possible impact of future commodity price changes on energy producers. Investors should be cautioned, however, that these measures should not be construed as an alternative to either net income (loss) or cash flow from operating activities, which are determined in accordance with IFRS, as indicators of the Company's performance.

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

	Three months ended September 30,		**Nine months ended September 30,**	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Cash flow provided by operating activities	23,884	1,491	54,782	56,665
Change in non-cash working capital	370	8,726	(1,610)	(13,143)
Adjusted EBITDA	**24,254**	**10,217**	**53,172**	**43,522**

Net debt, as defined above, is calculated as follows:

($ thousands)	**As at September 30, 2021**	**As at December 31, 2020**	**As at September 30, 2020**
Total liabilities	273,926	365,177	383,216
Decommissioning obligation	(7,537)	(6,250)	(7,224)
Financial derivative liability	(32,973)	(10,020)	(3,502)
Lease liability	(1,256)	(1,617)	(1,801)
Total current assets	(46,296)	(20,384)	(20,930)
Net Debt	**185,864**	**326,906**	**349,759**

The calculation of operating netback and operating netback prior to hedging is found elsewhere within this MD&A.

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, the Company's plans, focus and strategy, the expected number of wells to be drilled in the fourth quarter of 2021, expectation that the Company will have a smaller hedging loss per Boe in the fourth quarter of 2021 and the reasons and assumptions therefor, expectation of a smaller hedging loss, in absolute dollar terms and on a per Boe basis in 2022 and the reasons therefor, estimated annual average production range for 2021, 2021 annual capital expenditures and expectation that such expenditures will result in additional production in early 2022, capital expenditures will be funded substantially within operation cash flow for 2021, expectation that the Company will significantly enhance free cash flow in 2022, timing of hedges to expire, the Company's derivative instruments, the terms thereof and the anticipated benefits, anticipated timing to complete wells, the term out and maturity dates of the senior credit facility, methods the Company will use to monitor cash flow and terms of contractual obligations and other commercial commitments, may constitute forward looking statements and necessarily involve risks including, without limitation, risks associated with oil and gas development, exploitation, production, marketing and transportation of oil, natural gas, and natural gas liquids, loss of markets, impact of the COVID-19 pandemic and the ability of the Company to carry on operations as contemplated in light of the COVID-19 pandemic, determinations by OPEC and other countries as to production levels, volatility of commodity prices, currency fluctuations, inability to transport or process natural gas at economic rates or at all, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services at reasonable costs or at all, unforeseen challenges or circumstances in drilling, equipping and completing wells leading to higher capital costs than anticipated, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions or drilling operations, risks associated with PetroShale's non-operated status on some of its properties, production delays resulting from an inability to obtain required regulatory approvals or services, unfavorable weather, or the tie-in of associated natural gas production and an inability to access sufficient capital from internal and external sources.

The Company's actual results may differ materially from those expressed in, or implied by, the forward-looking statements. Forward looking statements or information is based on several factors and assumptions which have been used to develop such statements and information, but which may prove to be incorrect. Although PetroShale believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document and other documents filed by the Company, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic, regulatory and political environment in which PetroShale operates; the impact (and the duration thereof) that the COVID-19 pandemic will have on (i) the demand for tight oil, shale gas and NGLs, (ii) our supply chain, including our ability to obtain the equipment and services we require, and (iii) our ability to produce, transport and/or sell our tight oil, shale gas and NGLs; the ability of the Company to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the Company and the operators of its non-operated properties to operate in the field in a safe, efficient, compliant and effective manner; PetroShale's ability to obtain financing on acceptable terms or at all; changes in the Company's credit facilities including changes to borrowing base and maturity dates; receipt of regulatory approvals; field production rates and decline rates; the ability of the Company, and the operators of its non-operated properties, to tie-in associated natural gas production in an economic manner, or at all; the ability to manage lease operating and transportation costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the ability to convert non-producing proved and undeveloped or probable oil and natural gas reserves to producing reserves; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate transportation for commodity production; future petroleum and natural gas prices; differentials between benchmark commodity prices and those received by the Company for its production in the field; currency exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; PetroShale's ability to successfully drill, complete and commence production at commercial rates from its operated wells; and PetroShale's ability, or those of the operators of its non-operated properties, to successfully market its petroleum and natural gas products. Readers are cautioned that the foregoing list of factors is not exhaustive.

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

Oil and Gas Advisories

This document contains metrics commonly used in the oil and natural gas industry, such as "operating netback" These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included to provide readers with additional information to evaluate the Company's performance however, such metrics should not be unduly relied upon for investment or other purposes. Management uses these metrics for its own performance measurements and to provide readers with measures to compare PetroShale's performance over time.

Financial and Operational Highlights

	Three months ended September 30,		Nine months ended September 30,	
	2021	2020	2021	2020
Financial *($ thousands, except share amounts)*				
Petroleum and natural gas revenue	68,198	32,928	156,457	106,238
Cash provided by operating activities	23,884	1,491	54,782	56,665
Net income (loss)	14,954	(9,134)	(25,893)	(49,568)
Per share income (loss) – diluted	0.03	(0.05)	(0.06)	(0.26)
Adjusted EBITDA (1)	24,254	10,217	53,172	43,522
Capital expenditures, net	20,386	2,559	33,099	32,454
Net debt (1)			185,864	349,759
Number of common shares outstanding:				
Weighted average – basic	521,032,038	187,803,375	401,671,289	188,117,408
Weighted average - diluted	535,727,797	195,913,542	416,367,048	196,227,575
Operating				
Number of days	92	92	273	274
Daily production: (2)				
Tight oil (Bbls)	8,122	7,983	6,791	9,180
Shale gas (Mcf)	11,384	11,471	11,095	11,567
Natural gas liquids (Bbls)	1,794	2,066	1,787	2,063
Barrels of oil equivalent	11,814	11,961	10,427	13,171
Average realized price:				
Tight oil ($/Bbl)	85.49	46.61	78.98	43.85
Shale gas ($/Mcf)	3.98	1.15	3.74	1.46
Natural gas liquids ($/Bbl)	34.26	10.52	28.58	6.97
Netback ($ per Boe): (1)				
Petroleum and natural gas revenue	62.75	29.92	54.96	29.44
Royalties	(11.66)	(5.43)	(10.16)	(5.42)
Realized loss on financial derivatives	(13.68)	(3.57)	(11.47)	(0.46)
Lease operating costs	(6.41)	(3.95)	(6.01)	(4.84)
Workover expense	(1.12)	(1.24)	(1.21)	(0.74)
Production taxes	(4.71)	(2.43)	(4.07)	(2.44)
Transportation expense	(1.83)	(2.42)	(1.95)	(2.42)
Operating netback (1)	23.34	10.88	20.09	13.12
Operating netback prior to hedging (1)	37.02	14.45	31.56	13.58

(1) Non-IFRS measure – see page 4 for a reconciliation of adjusted EBITDA and net debt and a description of operating netback and operating netback prior to hedging.

(2) The Company's reserves have been categorized as Tight Oil, Shale Gas, and Natural Gas Liquids pursuant to National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

Management's Discussion and Analysis

Description of Business

PetroShale Inc. ("PetroShale" or the "Company") is an independent oil company focused on the acquisition, development, and production of oil-weighted assets in the Bakken and Three Forks formations in the Williston Basin area of North Dakota. The Company's common shares are listed on the TSX Venture Exchange under the "PSH" ticker symbol.

The Company has corporate offices located at 421 - 7th Avenue SW, Suite 3230, Calgary, Alberta T2P 4K9 and at 303 E. 17th Avenue, Suite 940, Denver, CO 80203.

Recent Developments

In the third quarter of 2021, the Company recognized production from 19 (4.25 net wells) newly completed non-operated wells. 14 of these wells were previously drilled and uncompleted wells ("DUCs") while five were drilled and completed in the quarter. All wells are currently producing consistent with expectations. Additionally, the Company expects six gross operated (4.95 net) wells and five gross non-operated (0.02 net) wells to commence production later in the fourth quarter of 2021 or early in the first quarter of 2022.

The Company recorded an operating netback before hedging losses of $31.56 per Boe in the first nine months of 2021 ($13.58 for the nine months ended September 30, 2020). During the nine-month period ended September 30, 2021, the Company realized $32.7 million ($11.47 per Boe) in hedging losses, resulting in the Company recording an operating netback of $20.09 per Boe for the nine months ended September 30, 2021 ($13.12 for the nine months ended September 30, 2020). Based on the additional wells placed on production during the third quarter of 2021, assuming similar benchmark commodity prices, the Company anticipates a smaller hedging loss per Boe in the fourth quarter of 2021 as compared to the year to date average loss. In addition, with the majority of the current hedges rolling off at the end of the year, assuming similar benchmark commodity prices, management anticipates a smaller realized hedging loss, in absolute dollar terms and on a per Boe basis, and a consequent increase in cash flows from operations in 2022.

As a result of the volatile economic environment and severe downturn in crude oil and natural gas prices in early 2020, as well as the unprecedented impact of the COVID-19 pandemic, the Company completed a process to optimize the capital structure, reduce debt, increase financial flexibility, and position PetroShale for long-term success. On April 8, 2021, the Company completed a series of agreements (the "Recapitalization Agreements") with its largest common shareholder, Mr. M. Bruce Chernoff (the Company's Executive Chairman and a director), a company of which Mr. Chernoff is a significant shareholder ("ChernoffCo"), and FR XIII PetroShale Holdings L.P. ("First Reserve" or the "Investor"), the former sole owner of the Company's wholly owned subsidiary's preferred shares, initiated a rights offering to its shareholders and reached an agreement in principle in respect of the Company's credit facility with the Company's bank lending syndicate, collectively, to fundamentally improve PetroShale's capital structure. Via this process, the Company raised $30.0 million of equity and eliminated the preferred share obligation, reducing net debt by $102.8 million. Refer to the "Liquidity and Capital Resources" section later in this MD&A and Note 10 to the Company's interim consolidated financial statements for further information.

For the calendar year 2021, the Company expects to achieve annual average production between 10,500 Boepd and 11,000 Boepd. In light of strong commodity prices, management previously increased annual capital expenditure guidance to $70-$75 million, which will result in additional production in the first quarter of 2022. These capital expenditures will be funded substantially within operating cash flow for 2021 and the increased production is expected to significantly enhance free cash flow in 2022.

Results of Operations

Production

	Three months ended September 30,			Nine months ended September 30,		
	2021	2020	% change	2021	2020	% change
Tight oil (Bbls per day)	8,122	7,983	1.7	6,791	9,180	(26.0)
Shale gas (Mcf per day)	11,384	11,471	(0.8)	11,095	11,567	(4.1)
Natural gas liquids (Bbls per day)	1,794	2,066	(13.2)	1,787	2,063	(13.4)
Total (Boe per day)	11,814	11,961	(1.2)	10,427	13,171	(20.8)
Liquids percentage of total	83.9	84.0	(0.1)	82.3	85.4	(3.6)

Tight oil production during the three-month period ended September 30, 2021 was higher versus the comparative period in the prior year as wells were brought on production and existing wells were returned to production. Tight oil and shale gas production during the nine months ended September 30, 2021 was lower than the comparable prior year period as a result of natural reservoir decline rates in the first half of 2021, particularly on wells brought online in late 2019 which were newly producing in 2020. Additionally, total production for the three and nine months ended September 30, 2021 decreased compared to prior periods due to temporary shut-ins following operated and non-operated well workover and surrounding well completion activity in the first half of 2021 as well as reduced capital spending in the last half of 2020 and the first half of 2021 while the Company sought to preserve financial liquidity. 37 gross (1.50 net) wells were brought online in the first and second quarter of 2021 and an additional 19 gross (4.25 net) wells commenced production in the third quarter of 2021. Comparatively, 39 gross (3.3 net) wells came online throughout 2020. The majority of the net wells brought online in the third quarter of 2021 commenced production in the early part of the quarter. Six gross operated (4.95 net) wells are expected to commence production in the first quarter of 2022. Production during the nine months ended September 30, 2021 was comprised of 65.1% tight oil, 17.2% natural gas liquids, and 17.7% shale gas compared to 69.7% tight oil, 15.7% natural gas liquids, and 14.6% shale gas in the corresponding period during 2020.

Pricing

	Three months ended September 30,			Nine months ended September 30,		
	2021	2020	% change	2021	2020	% change
Average Benchmark Prices (US$)						
Crude oil – WTI (per Bbl)	70.56	40.93	72.4	64.82	38.32	69.2
Natural gas – HH spot (per Mmbtu)	4.36	2.00	118.0	3.62	1.87	93.6
Average Differential (US$)						
Crude oil (per Bbl)	(2.70)	(5.94)	(54.5)	(1.71)	(5.92)	(71.1)
Natural gas (per Mcf) (1)	(1.20)	(1.13)	(6.2)	(0.63)	(0.79)	(20.3)
Average Realized Prices (US$) (2)						
Tight oil (per Bbl)	67.86	34.99	93.9	63.11	32.40	94.8
Shale gas (per Mcf)	3.16	0.87	263.2	2.99	1.08	176.9
Natural gas liquids (per Bbl)	27.20	7.89	244.7	22.84	5.15	343.5
Average Realized Prices (CAD$) (2)						
Tight oil (per Bbl)	85.49	46.61	83.4	78.98	43.85	80.1
Shale gas (per Mcf)	3.98	1.15	246.1	3.74	1.46	156.2
Natural gas liquids (per Bbl)	34.26	10.52	225.7	28.58	6.97	310.0

(1) Includes conversion from Mmbtu to Mcf

(2) Excluding transportation and processing costs

After a steep decline in the first half of 2020, benchmark commodity prices rebounded through the second half of 2020 and have substantially increased throughout 2021. The Company's average basis differential for crude oil has significantly improved during the three and nine months ended September 30, 2021 after widening throughout the majority of 2020, contributing to a significant improvement in realized tight oil prices.

Henry Hub benchmark natural gas prices increased considerably during 2021 when compared to 2020 with significant improvements realized in the third quarter of 2021 resulting in higher realized shale gas prices. NGL prices reflected the improvement in oil prices.

Revenues and Royalties

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	2021	2020	% change	2021	2020	% change
Petroleum and natural gas revenue	68,198	32,928	107.1	156,457	106,238	47.3
Less: royalties	(12,668)	(5,979)	111.9	(28,914)	(19,551)	47.9
Petroleum and natural gas revenue, net	55,530	26,949	106.1	127,543	86,687	47.1
Royalties as a percentage of revenue	18.6%	18.2%	2.3	18.5%	18.4%	0.4
Per Boe amounts:						
Petroleum and natural gas revenue	62.75	29.92	109.7	54.96	29.44	86.7
Less: royalties	(11.66)	(5.43)	114.7	(10.16)	(5.42)	87.5
Petroleum and natural gas revenue, net	51.09	24.49	108.6	44.80	24.02	86.5

The increase in revenues during the quarter ended September 30, 2021 compared to the prior year period is primarily due to the increase in realized commodity prices and increased oil production as discussed above.

The Company's royalty rate as a percentage of revenues was consistent in the three-month and nine-month periods ended September 30, 2021, as compared to the prior year periods.

Realized and Unrealized Gain (Loss) on Financial Derivatives

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Realized loss on financial derivatives	(14,868)	(3,933)	278.0	(32,658)	(1,657)	1,870.9
Unrealized gain (loss) on financial derivatives	7,454	3,301	125.8	(22,489)	(3,537)	535.8
Realized loss on financial derivatives per Boe	(13.68)	(3.57)	283.2	(11.47)	(0.46)	2,393.5

The Company realized losses on its financial derivatives in the nine months ended September 30, 2021 due to improving oil prices during the period and the lower priced hedges that were entered into during the volatile oil markets of 2020 to reinforce the capital structure. The Company is currently hedged on a portion of its anticipated net future oil production into the fourth quarter of 2022 at higher effective prices. Refer to the Financial Derivatives and Hedging Activities table below for further details.

Operating Expense

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Lease operating costs	6,967	4,346	60.3	17,110	17,459	(2.0)
Workover expense	1,216	1,365	(10.9)	3,455	2,681	28.9
Production taxes	5,117	2,675	91.3	11,599	8,806	31.7
Total operating expense	13,300	8,386	58.6	32,164	28,946	11.1
Per Boe amounts:						
Lease operating costs	6.41	3.95	62.3	6.01	4.84	24.2
Workover expense	1.12	1.24	(9.7)	1.21	0.74	63.5
Production taxes	4.71	2.43	93.8	4.07	2.44	66.8
Total operating expense	12.24	7.62	60.6	11.29	8.02	40.8
Production taxes – % of net revenue	9.2%	9.9%	(7.1)	9.1%	10.2%	(10.8)

Lease operating costs

Lease operating costs increased for the three months ended September 30, 2021 over the prior year period primarily due to increased variable costs and workover operations versus the same period in the prior year. Lease operating costs decreased during the nine months ended September 30, 2021 versus the same period in 2020 as there were fewer wells on production in the first half of 2021. As a result of ongoing production optimization efforts, lease operating costs per Boe increased during the three-month and nine-month periods ended September 30, 2021 compared to the same periods in 2020 due to the fixed cost component.

Workover expense

Workover expense, by its nature, will vary from period to period depending on the level of workover activity and may not be consistent with production levels. With the improved commodity pricing environment in 2021, workover expense increased during the nine months ended September 30, 2021 versus the prior year period in absolute and per Boe terms as the Company performed workovers to optimize and return operated wells to production. For the three-month period ended September 30, 2021 versus the three months ended September 30, 2020, workover expense decreased as the majority of the wells were returned to production in the first half of 2021.

Production taxes

North Dakota assesses a 5% oil severance tax and a 5% oil extraction tax on the gross value of after-royalty volumes produced at the wellhead, with certain defined exemptions. Absolute production taxes and production taxes per Boe are higher than the comparable prior year periods primarily due to improved pricing and are consistent with the changes in the Company's average realized prices as discussed in the Pricing section above.

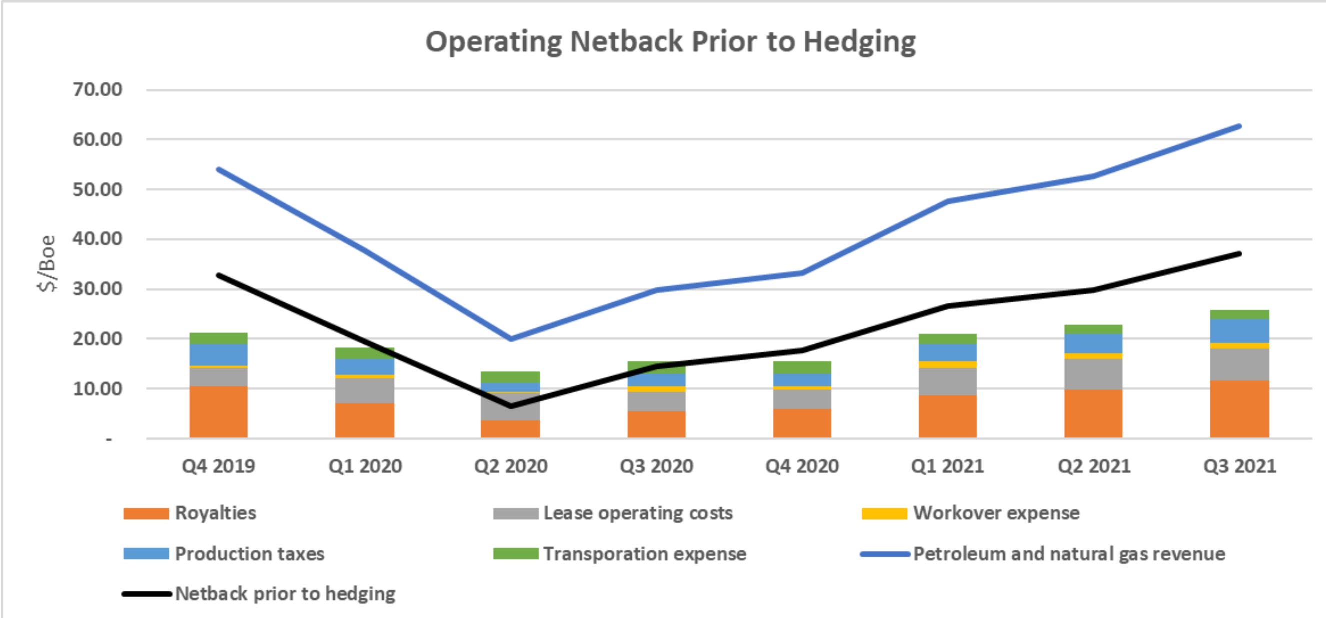
Transportation expense

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Transportation expense	1,987	2,665	(25.4)	5,537	8,734	(36.6)
Transportation expense per Boe	1.83	2.42	(24.4)	1.95	2.42	(19.4)

Transportation costs associated with the Company's petroleum production are netted against the related revenue if they are incurred following the transfer of control to the entity which has purchased the commodity. If transportation costs are incurred prior to the sale of the production, such costs are reflected separately as an expense in the consolidated statement of operations. Transportation costs were lower in the three-month and nine-month periods ended September 30, 2021 when compared to the same periods in 2020 due to the decreased average oil transportation rates and a decrease in production through the first three quarters of 2021. Transportation expense per Boe also decreased versus the prior period as the Company's production profile was favored by lower transportation rates than in the prior year comparative periods.

Operating Netback

	Three months ended September 30,			Nine months ended September 30,		
($ per Boe)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Petroleum and natural gas revenue	62.75	29.92	109.7	54.96	29.44	86.7
Royalties	(11.66)	(5.43)	114.7	(10.16)	(5.42)	87.5
Realized (loss) gain on financial derivatives	(13.68)	(3.57)	283.2	(11.47)	(0.46)	2,393.5
Lease operating costs	(6.41)	(3.95)	62.3	(6.01)	(4.84)	24.2
Workover expense	(1.12)	(1.24)	(9.7)	(1.21)	(0.74)	63.5
Production taxes	(4.71)	(2.43)	93.8	(4.07)	(2.44)	66.8
Transportation expense	(1.83)	(2.42)	(24.4)	(1.95)	(2.42)	(19.4)
Operating netback	23.34	10.88	114.5	20.09	13.12	53.1
Operating netback prior to hedging	37.02	14.45	156.2	31.56	13.58	132.4



General and Administrative ("G&A") Expense

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Gross G&A expense	1,673	2,003	(16.5)	5,400	4,856	11.2
Capitalized G&A	(338)	(129)	162.0	(790)	(506)	56.1
Overhead recovery	(214)	(145)	47.6	(598)	(541)	10.5
Net G&A expense	1,121	1,729	(35.2)	4,012	3,809	5.3
Net G&A expense per Boe	1.03	1.57	(34.4)	1.41	1.06	33.0

Gross G&A costs for the three-month period ended September 30, 2021 decreased versus the prior year period due to reduced consulting and legal fees. Net G&A costs for the three months ended September 30, 2021 decreased substantially due to improved overhead recoveries as the Company continues to operate more producing wells and increased capitalized G&A as a result of increased capital activity. Gross G&A for the nine-month period ended September 30, 2021 increased when compared to the prior year periods. The increase is primarily due to increased legal and advisory expense associated with the Recapitalization Agreements that were completed in the second quarter of 2021. Net G&A per Boe for the nine months ended September 30, 2021 increased versus the prior year due to the decrease in production and increase in gross G&A costs.

Depreciation and Depletion Expense

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Depreciation and depletion expense	13,383	15,774	(15.2)	34,327	52,198	(34.2)
Depreciation and depletion expense per Boe	12.31	14.34	(14.2)	12.06	14.46	(16.6)

Depreciation and depletion expense, on an absolute dollar and per Boe basis, decreased during the three and nine months ended September 30, 2021 as compared to the prior periods due to reduced production volumes versus the same period in the prior year and a lower depletable base (assets plus future development costs).

Impairment and Impairment Recovery

	Three months ended September 30,			Nine months ended September 30,		
($ thousands except where noted)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Impairment (impairment recovery)	-	-	-	(19,324)	24,000	(180.5)
Impairment (impairment recovery) per Boe	-	-	-	(6.79)	6.65	(202.1)

The Company evaluates its developed and producing ("D&P") assets for impairment indicators that may suggest the carrying value of these assets may not be recoverable. If such impairment indicators exist, impairment is determined by comparing the carrying amount of D&P assets to the greater of the assets value in use or its estimated fair value less selling costs. If the carrying amount is in excess of the estimated recoverable value, the Company will record an impairment expense related to the D&P assets. Alternatively, impairment losses may be reversed in future periods if the estimated recoverable amount of the D&P assets exceed the carrying value. The impairment recovery is limited to a maximum of the previously recognized impairment expense, net of any depletion that would have occurred if not for the impairment.

Determining the estimated cash flows associated with the Company's proved plus probable reserves is an inherently complex process involving the exercise of professional judgment and the use of significant estimates, including future commodity prices, differentials, discount rates, production volumes, royalties, operating costs, and future capital expenditures.

During the quarter ended March 31, 2020, the significant decline in oil prices was deemed an indicator of impairment and, as a result, the Company performed an impairment test using its December 31, 2019 reserve report adjusted internally for activity during the three-month period ended March 31, 2020. Based on the results of this impairment test, the Company recognized an impairment charge of $24.0 million for the three months ending March 31, 2020 on the Company's D&P assets.

During the second quarter of 2021, management identified indicators of impairment recovery. After evaluating the carrying amount of D&P assets versus the estimated recoverable value, the Company recognized an impairment recovery of $19.3 million, primarily due to the increase in forecast benchmark commodity prices at June 30, 2021. The Company's impairment recovery reflects the full prior year impairment net of the related depletion expense impact.

At September 30, 2021, there were no indicators of impairment.

Finance Expense

	Three months ended September 30,			Nine months ended September 30,		
($ thousands)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Preferred share dividends	-	3,157	(100.0)	4,171	8,612	(51.6)
Senior credit facility interest	3,117	2,811	10.9	8,391	7,393	13.5
Preferred share accretion, net	-	575	(100.0)	683	2,069	(67.0)
Decommissioning obligation accretion	45	25	80.0	89	110	(19.1)
Operating lease and other	22	33	(33.3)	73	673	(89.2)
Total finance expense	**3,184**	**6,601**	**(51.8)**	**13,407**	**18,857**	**(28.9)**

Finance expense reflects costs primarily associated with the Company's senior credit facility and the preferred shares. The preferred shares, which were converted to common shares in April 2021, had been reflected as a financial liability in the statement of financial position for accounting purposes. Finance expense was lower period over period reflecting the conversion of the preferred shares, slightly offset by higher effective interest rates on the senior credit facility borrowings.

Deferred Income Tax Expense (Recovery)

Deferred income taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. Deferred income tax assets are recognized to the extent that it is probable that future taxable income will be available against which the deductible temporary differences and the carryforward of unused tax losses can be utilized. At September 30, 2021, the Company determined that the generation of future taxable income was not probable and thus a deferred tax recovery and asset were not recorded.

Share-based Compensation

	Three months ended September 30,			Nine months ended September 30,		
($ thousands)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Gross share-based compensation	271	318	(14.8)	901	767	17.5
Capitalized share-based compensation	(84)	(22)	281.8	(135)	(99)	36.4
Net share-based compensation	**187**	**296**	**(36.8)**	**766**	**668**	**14.7**

The Company has granted restricted share bonus awards and performance share bonus awards (collectively, the "share bonus awards") to certain directors, officers, and employees. Share bonus awards granted according to the plan vest over three years from the date of grant and expire before the end of the third year from the date of grant. Restricted share bonus awards vest pro rata, typically over a three-year period. Performance share bonus awards vest ratably over a three-year period based on achievement of certain performance hurdles and are subject to a multiplier between 0 and 2.0 times based on the Company's performance against specified key performance indicators. The share bonus awards may be settled by the Company, in its sole discretion, in cash and/or common shares of the Company. The estimated fair value of the share bonus awards is determined based on the current market value of the Company's common shares at the dates of grant and considering anticipated forfeiture rates. For purposes of valuing performance share bonus awards, the Company assumes a performance share bonus award multiplier of 1.0 times. A charge to income is reflected as share-based compensation expense in the consolidated statement of operations over the vesting period with a corresponding increase to contributed surplus in the consolidated statement of financial position.

Net share-based compensation expense increased in the nine months ended September 30, 2021 versus the comparable prior periods due to increased expense from additional restricted and performance share bonus awards/grants in the latter half of 2020 and the second quarter of 2021.

Foreign Currency Gain (Loss) and Translation Adjustment

	Three months ended September 30,		Nine months ended September 30,	
	2021	**2020**	**2021**	**2020**
Foreign currency translation rates – US$/CAD$:				
Average period exchange rate	1.2597	1.3323	1.2514	1.3537
Ending period exchange rate	1.2680	1.3383	1.2680	1.3383

The Company's interim consolidated financial statements are reported in Canadian dollars, which is the Company's presentation currency. Transactions of the Company's US subsidiary are recorded in US dollars, its functional currency, as this is the primary economic environment in which the subsidiary operates. The assets, liabilities, and results of operations of the Company's US subsidiary are translated to Canadian dollars in the interim consolidated financial statements according to the Company's foreign currency translation policy, with any corresponding gain or loss reflected as a currency translation adjustment in other comprehensive income. The Company experienced a currency translation gain of $5.8 million and $1.1 million for the three and nine months ended September 30, 2021, respectively (2020 – loss of $2.6 million, gain of $6.8 million), due to a recent strengthening of the US dollar to Canadian dollar and the fact that the carrying value of the Company's US dollar-denominated assets exceeds the carrying value of its liabilities.

Liquidity and Capital Resources

Summary

PetroShale's capital resources consist primarily of cash flow provided by operating activities, cash and cash equivalents and availability under the senior credit facility. The Company is dependent on cash on hand, operating cash flows and equity and/or debt issuances to finance capital expenditures and property acquisitions. Borrowings are managed in relation to credit capacity and ability to generate future operating cash flows to service such debt.

PetroShale continuously monitors production, commodity prices and/or resulting cash flows. Should the outlook for future cash flow forecasts reflect a significantly negative trend, the Company is capable of managing its cash flows by not consenting to participate in additional drilling proposed by the operators of its non-operated properties, by reducing its drilling and completion activity on its operated properties and by entering into commodity price hedge contracts. The Company considers its current and future financial capacity and liquidity before proceeding with additional wells on its operated lands.

During the second quarter of 2021, the Company utilized gross proceeds from the Recapitalization Agreements and free cash flow to reduce the amount drawn under the senior credit facility by approximately US$24.4 million. Free cash flow was used to further reduce senior credit facility balance by US$8.0 million during the three months ended September 30, 2021. The senior credit facility balance is US$141.5 million excluding unamortized debt issuance costs at September 30, 2021 (US$174.0 million at December 31, 2020), or US$135.6 million net of available cash (US$164.1 million at December 31, 2020). The available borrowing base of the senior credit facility was most recently reaffirmed in March 2021 at US$177.5 million and the next borrowing base redetermination is scheduled for May 2022. The Company has no other debt obligations.

As at September 30, 2021, the Company had a net working capital deficit of $7.5 million, excluding the current financial derivative liability of $31.4 million. With recent improvements to commodity pricing, significant decrease in net debt over the prior year, and improvements in commodity hedge contracts, the Company intends to invest in capital expenditures in a disciplined manner and continue to generate free cash flow during fiscal year 2022.

Cash Flow from Operating Activities

Cash flow provided by operating activities depends on several factors including commodity prices, royalty rates, production volumes, operating expenses, transportation expenses, and production taxes, which generate adjusted EBITDA, as well as the impact of changes in non-cash working capital. Net cash flow provided by operating activities was $54.8 million for the nine months ended September 30, 2021 as compared to $56.7 million for the comparable period in the prior year. Net cashflow provided by operating activities declined mainly due to a $11.6 million reduced contribution from changes in non-cash working capital offset by larger adjusted EBITDA in 2021. During the nine-month period ended September 30, 2021, adjusted EBITDA increased by approximately $9.7 million primarily due to significant improvements in netback after hedging losses.

Financial Derivatives and Hedging Activities

The Company's results of operations and cash flows provided by operating activities are impacted by changes in market prices for crude oil, natural gas and NGLs. The Company will, from time to time, enter into various derivative instruments to mitigate a portion of its exposure to adverse market changes in commodity prices. These derivative instruments allow the Company to predict with greater certainty the total revenue it will receive, provide stability to the Company's operating cash flows for capital spending planning purposes, and protect development and acquisition economics.

As at September 30, 2021, the Company had various oil and natural gas price derivative contracts outstanding. The tables below represent the weighted average price for each contract type by fiscal quarter for oil and natural gas derivative contracts, respectively:

Oil Contract Type	Quarter	Volume (Bbls/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Three-way collars						
	Q4 2021	5,500	-	24.55	38.23	47.34
Costless collars						
	Q1 2022	2,250	-	-	46.22	60.92
	Q2 2022	2,500	-	-	47.10	60.53
	Q3 2022	1,250	-	-	48.00	62.76
	Q4 2022	1,250	-	-	48.00	62.76
Fixed swaps						
	Q1 2022	1,118	56.85	-	-	-
	Q2 2022	833	58.63	-	-	-
	Q3 2022	417	62.78	-	-	-
	Q4 2022	317	62.78	-	-	-

Natural Gas Contract Type	Quarter	Volume (MMbtu/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Fixed swaps						
	Q1 2022	2,000	3.43	-	-	-
	Q2 2022	2,000	3.43	-	-	-
	Q3 2022	2,000	3.43	-	-	-

Capital Expenditures

	Three months ended September 30,			**Nine months ended September 30,**		
($ thousands)	**2021**	**2020**	**% change**	**2021**	**2020**	**% change**
Drilling, completion, and facilities	20,382	2,430	738.8	33,065	31,948	3.5
Dispositions	-	(23)	(100.0)	-	(23)	(100.0)
Other, net	4	129	(96.9)	34	506	(93.3)
	20,386	2,536	703.9	33,099	32,431	2.1
Non-cash:						
Capitalized share-based compensation	84	22	281.8	135	99	36.4
Decommissioning obligation	594	156	280.8	1,179	627	88.0
Total capital expenditures	**21,064**	**2,714**	**676.1**	**34,413**	**33,157**	**3.8**

Capital expenditures, consisting of capitalized development activity for the three months ended September 30, 2021, were funded from operating cash flows. For the past year, the Company has cautiously invested in capital expenditures to maintain production while exploiting existing opportunities via DUCs and new drills. In the third quarter, the Company commenced drilling of two gross operated (1.00 net) wells and participated in the completion of thirteen gross non-operated (2.66 net) well to maintain production through the third quarter of 2022. The two newly drilled operated wells are expected to be completed in the first quarter of 2022. Two gross operated wells (1.24 net) were completed in late September 2021 and six gross non-operated wells (1.60 net) were completed during the third quarter of 2021. The Company anticipates additional completions of non-operated wells, as well as new drilling operations, in the fourth quarter of 2021.

Senior Credit Facility

The Company maintains a senior revolving credit facility which is referred to as the senior credit facility in the consolidated statement of financial position. The borrowing capacity was reaffirmed at US$177.5 million in March 2021 by the lending syndicate. The term-out date was also extended to June 25, 2022, at which point, the facility can be further extended at the option of the lenders or converted to a one-year term loan. The amount of the facility is subject to a borrowing base test performed periodically based primarily on producing oil and natural gas reserves and using commodity prices estimated by the lender as well as other factors. The next borrowing base redetermination is scheduled for May 2022. A decrease in the borrowing base determined by the senior lenders in the future could result in a reduction to the credit facility, which may require a repayment to the lenders.

The credit facility is subject to certain non-financial covenants and the Company is in compliance with all covenants under the senior credit facility as at September 30, 2021. The credit facility has no financial covenants.

As at November 19, 2021, the net amount drawn under the Senior Credit Facility was US$147.1 million representing US$149.1 million of borrowings under the Senior Credit Facility and US$2.0 million of cash on hand.

Preferred Shares

The Company elected to pay its preferred share dividends due in May, August, and November of 2020 in-kind as a means of preserving liquidity. The Company also elected to pay its dividend due in February 2021 and accruing through March 2021 in-kind. The Company paid cash dividends for the period of April 1 through April 8, 2021. The preferred shares were converted to common shares in association with the Recapitalization Agreements in April 2021. Refer also to Note 9 in the Company's consolidated financial statements.

Share Capital

	As at November 19, 2021	As at September 30, 2021	As at December 31, 2020
Weighted average common shares outstanding:			
Basic		401,671,289	188,240,502
Diluted		416,367,048	195,784,268
Outstanding securities:			
Common shares	521,032,038	521,032,038	188,528,453
Preferred shares, convertible	-	-	75,000
Stock options	-	-	550,000
Restricted share bonus awards	4,968,202	4,968,202	3,301,027
Performance share bonus awards	9,727,557	9,727,557	4,242,740

On completion of the transactions pursuant to the Recapitalization Agreements in April 2021, the preferred shares were converted to common shares and the voting rights associated with the preferred shares were cancelled.

The Company was previously authorized by the TSX Venture Exchange to commence in a normal course issuer bid ("NCIB"). During the quarter ended March 31, 2020, the Company purchased and cancelled 3,851,500 shares at an average price of $0.48 per common share for a total repurchase cost of $1.9 million under the NCIB. The NCIB expired on Feb 8, 2021 and was not renewed.

Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

The following is a summary of the Company's contractual obligations and commitments as at September 30, 2021:

($ thousands)	2021	2022	2023	2024	2025	Contractual Cash Flow
Accounts payable and accrued liabilities	53,395	-	-	-	-	53,395
Lease liability	127	346	239	260	284	1,256
Senior credit facility (1)	2,301	9,129	183,831	-	-	195,261

(1) Includes future interest expense at the rate of 5.09% being the rate applicable at September 30, 2021 to the currently established maturity date of June 25, 2023.

Off-Balance Sheet Arrangements

The Company 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 by the Company 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.

Letters of Credit

The Company has two outstanding letters of credit. A US$158,000 letter of credit was issued in the third quarter of 2021 for the Office of Natural Resources Revenue. A second letter is in favor of the energy regulator in North Dakota in the amount of US$75,000. As security, the Company has set aside an equivalent amount in cash at the financial institution that issued the letter of credit. In addition, the Company has advanced funds to other regulatory agencies of US$160,000 as security in order to operate in North Dakota.

Summary of Quarterly Results

($ thousands except where noted)	Sep 30 2021	Jun 30 2021	Mar 31 2021	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019
Revenues, net of royalty	55,530	36,561	35,452	30,564	26,949	19,820	39,918	48,883
Adjusted EBITDA	24,254	13,851	15,067	15,204	10,217	8,278	25,027	35,566
Cash flow – operating activities	23,884	15,005	15,893	13,326	1,491	16,336	38,837	27,677
Net income (loss)	14,954	3,578	(44,424)	(12,417)	(9,134)	(23,169)	(17,266)	9,609
Net income (loss) per share:								
Basic and Diluted	0.03	0.01	(0.24)	(0.07)	(0.05)	(0.12)	(0.09)	0.05

Revenues in the third quarter of 2021 increased 51.9% over the second quarter of 2021 due primarily to a 26.5% increase in production volumes and increased commodity pricing. Adjusted EBITDA and net income also improved in the third quarter of 2021 mainly as a result of production and pricing increases. Cash flow provided by operating activities increased in the third quarter 2021 versus the prior quarter due to improved volumes and pricing.

Revenues in the second quarter of 2021 remained consistent with the prior period as improved pricing was partially offset by a minor production decrease. Cash flow from operating activities and adjusted EBITDA were negatively impacted by the realized loss on financial derivatives, increased operating costs, and increased production taxes.

In the first quarter of 2021, revenues and cash flow from operating activities increased versus the prior quarter primarily as a result of improved pricing while Adjusted EBITDA remained relatively consistent due to the offsetting impacts of a higher operating netback and lower production.

Revenues, Adjusted EBITDA, and cash flow from operating activities increased during the fourth quarter of 2020 versus the prior quarter primarily as a result of improved pricing.

During the third quarter of 2020, revenues increased versus the previous quarter due the stabilization of oil prices. As a result, Adjusted EBITDA improved, and the net loss decreased versus the prior quarter. Cash flow declined due to changes in non-cash working capital.

Revenues declined in the second quarter of 2020 versus the first quarter due to a significant decline in oil prices, which contributed to a reduction in Adjusted EBITDA and cash flows and also resulted in a significant net loss.

Revenues, along with adjusted EBITDA and net income, decreased in the first quarter of 2020 compared to the fourth quarter of 2019 due to a 29% decrease in average realized prices partially offset by a 17% increase in sales volumes. The first quarter of 2020 also included at $24.0 million non-cash impairment charge related to the Company's developed and producing assets.

Critical Accounting Estimates

The timely preparation of the interim consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the interim consolidated financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates.

Critical judgments that have the most significant effect on the amounts recognized in the interim consolidated financial statements include the following:

Reserve Estimates

The estimation of recoverable quantities of proved and probable oil and natural gas reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices and differentials, estimated production and transportation costs, engineering data and the timing and amount of future expenditures, all of which are subject to uncertainty. The Company's reserve estimates are evaluated by independent professional engineers and are determined in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, *Standards of Disclosures for Oil and Gas Activities*, and the Canadian Oil and Gas Evaluation Handbook.

Reserve adjustments are made annually based on actual volumes produced, the results from capital expenditure programs, revisions to previous estimates, new discoveries and acquisitions and dispositions made during the year. Changes in reserve estimates can affect the impairment of assets, including the recovery of previously recorded impairment, the estimation of decommissioning obligations, and the amounts reported for depletion and depreciation of property, plant, and equipment.

Impairment

Each quarter, management reviews indicators of impairment (and indicators of impairment recovery as applicable) including internal and external sources of information including changes to reserve estimates, drilling results, performance of its oil and gas producing assets and changes in commodity prices. Significant judgment is involved when assessing such indicators of impairment and if indicators do exist, to prepare estimates of value in use and fair value less selling costs. Related estimates include assumptions as to appropriate discount factors and future commodity prices.

Decommissioning Obligation

The Company estimates the decommissioning obligations for oil and gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies, and the estimate of the discount rates used to determine the present value of these cash flows.

Business Combinations

In a business combination, 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 estimation of recoverable quantities of proved and probable reserves being acquired.

Share-Based Compensation

The Company's estimate of share-based compensation expense associated with stock option grants and the value of warrants issued is dependent upon estimates of expected volatility of the Company's share price and anticipated forfeiture rates of the related securities. The Company's estimate of share-based compensation expense associated with share bonus awards is dependent on an estimate of anticipated forfeiture rates of such securities.

Deferred Income Taxes

The calculation of deferred income taxes is based on a number of assumptions, including estimating the future periods in which temporary differences, tax losses and other tax credits will reverse, the use of substantively enacted tax rates at the balance sheet date and the likelihood of deferred tax assets being realized.

Derivatives

The Company's estimate of the fair value of derivative financial instruments is dependent upon estimated forward commodity prices and the volatility in those prices.

Preferred Shares

The Company's estimate of the preferred share obligation and preferred share equity component of its previously outstanding preferred shares was dependent on an estimate of the rate of interest which would be incurred by the Company on a similar debt obligation without a conversion feature.

Business Conditions and Risks

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/or equity financing at a reasonable cost, or at all. Operational risks include the performance of the Company's properties, safety and performance risks associated with drilling and well completion activities, competition for land and services, environmental factors, reservoir performance uncertainties, a complex regulatory environment, other safety concerns, and reliance on the operators of a portion of the Company's properties. When acquiring land, the Company uses technical and industry knowledge to evaluate potential hydrocarbon plays in order to pay what it believes are economically sound prices that will benefit PetroShale's shareholders. The Company's focus is on areas where the prospects are understood by management. There is risk that the Company may not realize the anticipated benefits of acquired properties or future development thereof.

The Company minimizes operational risks by hiring experienced management and engaging experienced service providers on our operated properties and by participating with well-established operators of our non-operated properties. On our non-operated properties, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of the Company's non-operated properties to adequately perform operations, an operator's breach of the applicable agreements or regulations or an operator's failure to act in ways that are in the Company's best interests could reduce production and revenues or could create a liability for the Company due to the operator's failure to properly maintain wells and facilities or to adhere to applicable safety and environmental standards. With respect to properties that the Company does not operate:

- The operator could refuse to initiate exploration or development projects
- If the Company proceeded with any of those projects the operator has refused to initiate, PetroShale may not receive any funding from the operator with respect to that project and thus bear all the capital 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 proceed on a different schedule than the Company anticipated, including expenditures to drill more wells or build more facilities 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
- The operator may not have adequate expertise or resources to perform operations efficiently

Any of these events, and the resulting activities, could significantly and adversely affect anticipated exploration and development activities conducted on its properties which the Company does not operate, and the results of those activities.

PetroShale's focus is on areas and geological formations in which the prospects are understood by management. Technological tools are extensively used to increase the probability of success and reduce risk.

PetroShale relies on appropriate sources of funding to support the various stages of the Company's business strategy. There is no guarantee that external sources of financing will be available in the future, on favorable terms or at all. The various sources of funding include:

- Internally generated cash flow from operations
- New common or preferred equity, if available on acceptable terms which may be utilized to fund acquisitions, to expand capital programs when appropriate and to repay any outstanding debt
- Debt, in the form of traditional oil and gas borrowing base bank facilities, and/or subordinated debt which typically has a higher cost than bank debt
- Disposition of non-core assets

The Company is exposed to commodity price and market risk for our principal products of tight oil, shale gas, and natural gas liquids. Commodity prices are influenced by a wide variety of factors, most of which are beyond PetroShale's control. In addition, the Company is exposed to fluctuations in the differentials between market price benchmarks and what is received in our geographic area of operation for our production. To manage this risk, the Company may enter 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. When considering if derivative contracts are warranted, the Company may also, from time to time, enter fixed physical contracts to hedge the realized prices from its production. 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. Although the Company's intent in entering such derivative contracts is to manage its exposure to fluctuations in commodity prices, such contracts may limit the Company's ability to fully realize the benefits of higher market prices.

Risk of cost inflation subjects the Company to potential erosion of product netbacks and returns from well drilling and completion activities. For example, increasing costs of crude oil and natural gas production equipment and services can inflate operating costs and/or drilling and well completion expenditures. In addition, increasing prices for undeveloped land can inflate costs of both asset and corporate acquisitions.

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a reasonable cost and produce them in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. The Company and the operators of its non-operated properties attempt to mitigate this risk by developing long-term relationships with suppliers and contractors.

Demand for crude oil, 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 offshore markets.

PetroShale mitigates the above-mentioned risks as follows:

- PetroShale and the operators of certain of our properties attempt to explore for and produce oil that is high quality (light, sweet), mitigating the Company's exposure to adverse quality differentials
- Natural gas production will generally be connected to established pipeline infrastructure or other local uses for the natural gas may be found
- Financial derivative instruments or fixed price physical contracts may be used where appropriate to manage commodity price volatility

The Company is exposed to operational risks in terms of engaging service suppliers and drilling contractors, the normal oilfield risks of dangerous operations and the potential for discharge of hazardous substances into the environment, arranging for marketing of the Company's tight oil and shale gas production, as well as financing the costs of completing wells and recovering a share of those costs from our non-operating partners. The Company has and will continue to engage appropriate resources to ensure these risks are managed to the extent possible.

PetroShale owns leases from individual mineral owners (Fee Leases), the State of North Dakota acting by and through the Board of University and School Lands (State Leases), individual native owners with approval from the Secretary of the Interior of the Bureau of Indian Affairs (Allotted or BIA Leases), and the Bureau of Land Management (Federal Leases). PetroShale adheres to the National Environmental Policy Act in its operations and is under the regulatory authority of the North Dakota Industrial Commission, the Bureau of Indian Affairs (BIA), the Bureau of Land Management and the Department of the Interior's Office of Natural Resources Revenue. The Allotted Leases are held in trust by the United States for the benefit of individual native owners and are subject to restrictions against alienation or encumbrance without approval of the Secretary of the Interior. All the Company's Allotted Leases are located within the boundaries of the Fort Berthold Indian Reservation (FBIR) which makes the Company subject to unique regulations that are not applicable to lands outside the FBIR. The Company mitigates regulatory risk by maintaining good relationships with the BIA and staying abreast of current regulations. PetroShale's ability to execute projects and realize the benefits therefrom is subject to factors beyond our control, including changes to regulations promulgated by any of the above entities.

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

Like most companies of our size, PetroShale has a limited number of accounting and finance personnel, and therefore it is difficult to create strong segregation of duties which is normally a feature of a company's internal control structure. Management mitigates this risk through performance of analytical review procedures on operating and financial results.

Environmental Risks

General Risks

Oil and gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the pollution of the environment, climate change and destruction of natural habitat, as well as safety risks such as personal injury. The Company works hard to identify the potential environmental impacts of its new projects in the planning stage and during operations. The Company conducts its operations with exacting standards in order to protect the environment, its employees and consultants, and the general public. The Company maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations. If the Company becomes subject to environmental liabilities without such insurance, the payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Climate Change Risks

Our exploration and production facilities and other operations and activities emit greenhouse gasses ("GHG") which may require us to comply with US federal and/or state GHG emissions legislation. Climate change policy is evolving at regional, national, and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, and/or US federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties. The Company has undertaken several initiatives, including continuous flaring reduction initiatives, transporting crude oil by pipeline rather than by truck, and connecting natural gas to pipeline connections to reduce GHG emissions from its operations. Climate change and related regulation and public response to such items may negatively impact demand for oil, natural gas and NGLs in the future, and could reduce market prices for our commodities.

Additional Risk Information

Additional information regarding risks including, but not limited to, business risks is available in the Company's Annual Information Form, a copy of which may be accessed through SEDAR website (www.sedar.com).

COVID-19 Impacts and Oil Pipeline Egress

In March 2020, a pandemic was declared by the World Health Organization due to the COVID-19 virus outbreak. Responses to the spread of COVID-19 resulted in a significant disruption to business operations and a significant increase in economic uncertainty. As a result, crude oil prices drastically declined due to a reduction in oil demand associated with the pandemic, combined with oversupply issues and disputes amongst major oil producing countries. Other economic impacts of the virus have included volatility in oil and gas asset prices, marked fluctuation in currency exchange rates, and a decline in long-term interest rates. More recently, economic activity has improved, commodity prices have increased, vaccines have been approved and a phased rollout has commenced throughout most developed countries.

During 2020, large-scale travel bans, stay-at-home orders, border closures and similar protective measures enacted by federal, foreign, state, and local governments to slow the spread of COVID-19 contributed to a significant deterioration in domestic and global demand for crude oil, and to a lesser extent, natural gas. Compounding the impact of COVID-19, the oil production output alliance between Russia, Saudi Arabia and other oil producing nations ("OPEC+") broke down in March 2020 as members were unable to reach agreement over how much to restrict production in order to stabilize crude oil prices. As a result, Saudi Arabia and Russia each initiated efforts to increase production, further driving down oil prices and increasing the global oversupply of crude oil. The excess supply of crude oil and demand imbalance resulted in the WTI crude oil price, the benchmark price for most of the Company's crude production, declining from US$57.53/Bbl in January 2020 to US$17.08/Bbl in April 2020. OPEC+ subsequently reached an agreement in April 2020 which included significant production cuts extending through April 2022. Crude oil prices have responded accordingly recovering to US$81.22/Bbl in October 2021 with recent spot pricing in excess of US$85.00/Bbl. Despite recent re-balancing of supply and demand for crude, uncertainties exist around the pace of increase in future economic activity, future actions of OPEC+, and the potential lifting of sanctions against Iran (a major oil producer), among other factors. As a result, crude oil prices could continue to be volatile and it is uncertain when business operations, including those the Company participates in, will return to conditions that existed prior to COVID-19.

The majority of crude oil currently sold in North Dakota is transported through the Dakota Access Pipeline (DAPL) to the US Gulf Coast. A short section of the DAPL crosses underneath Lake Oahe in South Dakota. In July 2020, a United States District Court Judge made a ruling that the US Army Corps of Engineers (USACE), which had provided a crossing permit under the lake, failed to prepare an environmental impact statement (EIS) for this particular easement. The United States District Court Judge ordered the DAPL to be shut down and emptied of oil while the USACE prepared the necessary environmental analysis. Energy Transfer, which owns the DAPL, and the USACE, appealed the decision to the DC Circuit Court of Appeals (DCCOA). The DCCOA reversed the order to suspend operations and empty the pipeline but upheld the vacatur of the easement under Lake Oahe. A decision by the DCCOA in January 2021 allowed DAPL to remain operational while the USACE prepares the EIS. USACE recently revised the estimated timeline for completion of the EIS from spring to fall of 2022; the agency intends to allow the pipeline to continue transporting crude in the interim. Both the State of North Dakota and the MHA Nation have issued statements and legal petitions in support of DAPL's continued operations. On September 22, 2021, the United States District Court Judge issued an order dismissing all outstanding counts in the case including the requirement that USACE file periodic status updates to the court on the progress of the EIS. The USACE will continue to provide monthly updates to the public and stakeholders on their environmental review, as required under the National Environmental Policy Act (NEPA). The Plaintiffs may still challenge the forthcoming EIS and/or Record of Decision (ROD) but must be done under separate legal action. Energy Transfer completed a proposed expansion of the DAPL in August 2021; the line now has the ability to flow approximately 750,000 barrels per day, an increased from 500,000 barrels per day. On September 20, 2021, Energy Transfer petitioned the DCCOA's finding to the US Supreme Court (SCOTUS); it is unknown if SCOTUS will hear the case in the upcoming term. In the event the DAPL would be required to shut down, management believes there is currently adequate excess rail capacity and alternative pipeline capacity to transport existing and projected production from the basin. Transporting crude oil by rail is more expensive than transportation through the DAPL and may lead to a decrease in realized crude oil prices if such an event occurs.

Additional Information

Additional information can be obtained by contacting the Company at PetroShale Inc., Suite 3230, 421-7th Avenue SW, Calgary, Alberta T2P 4K9 or by email at info@petroshaleinc.com. Additional information is also available on www.sedar.com or www.petroshaleinc.com.

Interim Consolidated Statements of Financial Position

(Unaudited)

($ thousands)	**Note**	**As at September 30, 2021**	**As at December 31, 2020**
Assets			
Current assets			
Cash and cash equivalents		7,428	2,830
Accounts receivable	3	38,427	17,232
Prepaid expenses and deposits		441	322
Total current assets		46,296	20,384
Restricted cash	14,15	299	300
Right of use assets	4	1,138	1,529
Property, plant and equipment, net	5	499,476	480,664
Total assets		**547,209**	**502,877**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	6	53,395	28,327
Financial derivative liability	15	31,361	10,020
Lease liability	4	416	472
Total current liabilities		85,172	38,819
Senior credit facility	7	178,765	221,915
Preferred share obligation	9	-	97,048
Financial derivative liability	15	1,612	-
Lease liability	4	840	1,145
Decommissioning obligation	8	7,537	6,250
Total liabilities		**273,926**	**365,177**
Shareholders' equity			
Common shares	10	365,904	198,925
Preferred share equity component	9	-	7,510
Contributed surplus	10	7,857	6,968
Accumulated deficit		(100,564)	(74,671)
Accumulated other comprehensive income (loss)		86	(1,032)
Total shareholders' equity		**273,283**	**137,700**
Commitments	14		
Subsequent events	17		
Total liabilities and shareholders' equity		**547,209**	**502,877**

See accompanying notes to the interim consolidated financial statements

Interim Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

		Three months ended September 30,		Nine months ended September 30,	
($ thousands, except per share amounts)	**Note**	**2021**	**2020**	**2021**	**2020**
Revenue					
Petroleum and natural gas	11	68,198	32,928	156,457	106,238
Less: Royalties		(12,668)	(5,979)	(28,914)	(19,551)
Petroleum and natural gas, net of royalties		55,530	26,949	127,543	86,687
Realized loss on financial derivatives	15	(14,868)	(3,933)	(32,658)	(1,657)
Unrealized gain (loss) on financial derivatives	15	7,454	3,301	(22,489)	(3,537)
Total revenue		**48,116**	**26,317**	**72,396**	**81,493**
Expenses					
Operating		13,300	8,386	32,164	28,946
Transportation	11	1,987	2,665	5,537	8,734
General and administrative		1,121	1,729	4,012	3,809
Depreciation and depletion	4,5	13,383	15,774	34,327	52,198
Impairment (impairment recovery)	5	-	-	(19,324)	24,000
Finance expense	13	3,184	6,601	13,407	18,857
Share-based compensation	10	187	296	766	668
Loss on modification of preferred shares	9	-	-	27,400	-
Total expenses		**33,162**	**35,451**	**98,289**	**137,212**
Income (loss) before income taxes		14,954	(9,134)	(25,893)	(55,719)
Deferred income tax recovery		-	-	-	(6,151)
Net income (loss)		**14,954**	**(9,134)**	**(25,893)**	**(49,568)**
Currency translation adjustment		5,839	(2,552)	1,118	6,849
Comprehensive income (loss)		**20,793**	**(11,686)**	**(24,775)**	**(42,719)**
Net income (loss) per share:					
Basic	12	0.03	(0.05)	(0.06)	(0.26)
Diluted	12	0.03	(0.05)	(0.06)	(0.26)

See accompanying notes to the interim consolidated financial statements

Interim Consolidated Statements of Changes in Shareholders' Equity
(Unaudited)

($ thousands, except share amounts)	**Voting Common Shares**	**Share Capital**	**Preferred Share Equity Component**	**Contributed Surplus**	**Accumulated Deficit**	**Accumulated Other Comprehensive Income (Loss)**	**Shareholders' Equity**
December 31, 2019	**191,185,628**	**200,630**	**7,510**	**6,191**	**(12,686)**	**(444)**	**201,201**
Purchase of common shares for cancellation	(3,865,000)	(1,859)	-	-	-	-	(1,859)
Settlement of share bonus awards	1,036,587	135	-	(237)	-	-	(102)
Share-based compensation, gross	-	-	-	767	-	-	767
Net loss	-	-	-	-	(49,568)	-	(49,568)
Other comprehensive income	-	-	-	-	-	6,849	6,849
September 30, 2020	**188,357,215**	**198,906**	**7,510**	**6,721**	**(62,254)**	**6,405**	**157,288**
December 31, 2020	**188,528,453**	**198,925**	**7,510**	**6,968**	**(74,671)**	**(1,032)**	**137,700**
Settlement of share bonus awards	27,787	7	-	(12)	-	-	(5)
Settlement of stock options	200,000	39	-	-	-	-	39
Share-based compensation, gross	-	-	-	901	-	-	901
Loss on modification of preferred shares	-	-	27,400	-	-	-	27,400
Recapitalization Agreements – Conversion of Preferred Shares	182,275,798	136,933	(34,910)	-	-	-	102,023
Recapitalization Agreements – Rights Offering	29,252,965	5,900	-	-	-	-	5,900
Recapitalization Agreements – Private Placements	120,747,035	24,100	-	-	-	-	24,100
Net loss	-	-	-	-	(25,893)	-	(25,893)
Other comprehensive income	-	-	-	-	-	1,118	1,118
September 30, 2021	**521,032,038**	**365,904**	-	**7,857**	**(100,564)**	**86**	**273,283**

See accompanying notes to the interim consolidated financial statements

Interim Consolidated Statements of Cash Flows

(Unaudited)

		Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**Note**	**2021**	**2020**	**2021**	**2020**
Operating activities					
Net income (loss)		14,954	(9,134)	(25,893)	(49,568)
Operating items not affecting cash:					
Depreciation and depletion	4,5	13,383	15,774	34,327	52,198
Impairment (impairment recovery)	5	-	-	(19,324)	24,000
Loss on modification of preferred shares	9	-	-	27,400	-
Gain on sale of other assets		-	(19)	-	(19)
Deferred income tax recovery		-	-	-	(6,151)
Unrealized loss (gain) on financial derivatives	15	(7,454)	(3,301)	22,489	3,537
Share-based compensation	10	187	296	766	668
Finance expense	13	3,184	6,601	13,407	18,857
Change in non-cash working capital	16	(370)	(8,726)	1,610	13,143
Cash provided by operating activities		**23,884**	**1,491**	**54,782**	**56,665**
Investing activities					
Additions to property, plant, and equipment	5	(20,386)	(2,559)	(33,099)	(32,454)
Proceeds from sale of other assets		-	23	-	23
Change in non-cash working capital	16	6,534	(9,178)	4,424	(47,380)
Cash used in investing activities		**(13,852)**	**(11,714)**	**(28,675)**	**(79,811)**
Financing Activities					
Proceeds from (repayments to) senior credit facility, net	7	(10,133)	(1,698)	(40,668)	37,570
Debt issuance costs	7	96	-	(666)	-
Payment of interest and preferred dividends	16	(3,067)	(2,945)	(8,670)	(10,493)
Payment of lease liabilities	4	(135)	(113)	(421)	(353)
Proceeds from Recapitalization Agreements	7,10	-	-	29,271	-
Settlement of share bonus awards	10	-	(71)	(5)	(102)
Proceeds from exercise of stock options	10	-	-	39	-
Purchase of common shares for cancellation	10	-	-	-	(1,859)
Cash (used in) financing activities		**(13,239)**	**(4,827)**	**(21,120)**	**24,763**
Change in cash and cash equivalents		(3,207)	(15,050)	4,987	1,617
Effect of foreign exchange rate changes		147	610	(389)	865
Cash and cash equivalents, beginning of period		10,488	17,529	2,830	607
Cash and cash equivalents, end of period		7,428	3,089	7,428	3,089

See accompanying notes to the interim consolidated financial statements

Notes to the Interim Consolidated Financial Statements

As at September 30, 2021 and for the three and nine months ended September 30, 2021 and 2020

Note 1. Description of Business

PetroShale Inc. (the "Company") is an independent oil company focused on the acquisition, development, and production of oil-weighted assets in the Bakken and Three Forks formations in the Williston Basin area of North Dakota. The Company's common shares are listed on the TSX Venture Exchange under the "PSH" ticker symbol. The Company has corporate offices located at 421 - 7th Avenue SW, Suite 3230, Calgary, Alberta T2P 4K9 and at 303 E. 17th Avenue, Suite 940, Denver, CO 80203.

Note 2. Basis of Presentation

Basis of Measurement and Statement of Compliance

These interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "Interim Financial Reporting" ("IAS 34"), and have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements for the year ended December 31, 2020. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss.

Certain information and disclosures normally included in the notes to the annual consolidated financial statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim consolidated financial statements should be read in conjunction with the annual consolidated financial statements for the year ended December 31, 2020, which have been prepared in accordance with IFRS as issued by the IASB.

These interim consolidated financial statements were approved for issuance by the Board of Directors on November 19, 2021.

Use of Estimates, Judgments and Assumptions

The timely preparation of the interim consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the interim consolidated financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates, judgments, and assumptions.

In early March 2020, the World Health Organization declared the COVID-19 coronavirus outbreak to be a pandemic. Responses to the spread of COVID-19 have resulted in significant disruption to business operations and a significant increase in economic uncertainty, with more volatile commodity prices and currency exchange rates, and a decline in long-term interest rates. These events have resulted in a challenging economic climate in which it is difficult to reliably estimate the length or severity of these developments and their financial impact. The results of the potential economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's estimates reflected in these financial statements and as described herein; however, there could be a further prospective material impact in future periods.

Note 3. Accounts Receivable

($ thousands)	**As at September 30, 2021**	**As at December 31, 2020**
Accounts receivable – petroleum and natural gas	30,768	15,386
Accounts receivable – joint interest billing and other	7,659	1,846
Total	**38,427**	**17,232**

Note 4. Right of Use Assets and Lease Liability

The Company's right of use assets and lease liability relate to a lease for its Denver office space as well as a lease for a field compressor.

Right of Use Assets

($ thousands)	
January 1, 2020	**445**
Additions	1,901
De-recognition	(242)
Depreciation	(502)
Effect of foreign currency rate changes	(73)
December 31, 2020	**1,529**
Depreciation	(381)
Effect of foreign currency rate changes	(10)
September 30, 2021	**1,138**

Lease Liability

($ thousands)	
January 1, 2020	**453**
Additions	1,901
De-recognition	(247)
Payments	(479)
Lease interest expense	65
Effect of foreign currency rate changes	(76)
December 31, 2020	**1,617**
Payments	(421)
Lease interest expense	70
Effect of foreign currency rate changes	(10)
September 30, 2021	**1,256**

Note 5. Property, Plant and Equipment

($ thousands)	Developed and Producing	Other	Total
December 31, 2019	**543,222**	**142**	**543,364**
Additions	35,175	(1)	35,174
Capitalized share-based compensation	127	-	127
Decommissioning obligation	(32)	-	(32)
Impairment	(24,000)	-	(24,000)
Depreciation and depletion	(65,504)	(122)	(65,626)
Effect of foreign currency rate changes	(8,344)	1	(8,343)
December 31, 2020	**480,644**	**20**	**480,664**
Additions, net	33,065	34	33,099
Capitalized share-based compensation	135	-	135
Decommissioning obligation	1,179	-	1,179
Impairment recovery	19,324	-	19,324
Depreciation and depletion	(33,926)	(20)	(33,946)
Effect of foreign currency rate changes	(977)	(2)	(979)
September 30, 2021	**499,444**	**32**	**499,476**

Depreciation, Depletion, and Future Development Costs

For the nine months ended September 30, 2021 and 2020, PetroShale recorded $33.9 million and $51.7 million, respectively, of depreciation and depletion expense on its developed and producing ("D&P") assets, which reflected an estimated US$282.2 million and US$315.4 million, respectively, of future development costs associated with proved plus probable reserves.

Impairment

Determining the estimated cash flows associated with the Company's proved plus probable reserves is an inherently complex process involving the exercise of professional judgment and the use of significant estimates, including future commodity prices, differentials, discount rates, production volumes, royalties, operating costs, and future capital expenditures. In future periods, previous impairments may be reversed up to the original carrying value less any associated depreciation and depletion if the estimated recoverable amounts of the D&P assets exceed their carrying amount.

During the first quarter of 2020, PetroShale recognized an impairment charge of $24.0 million on the Company's D&P assets. The impairment was attributable to declines in current and forecasted crude prices during that time.

At June 30, 2021, the increase and more recent stability in forecast benchmark commodity prices, as well as improvement in Company valuation, since the last impairment test at March 31, 2020, were deemed to be indicators of impairment recovery. As a result, the Company prepared an impairment recovery test to ascertain the present value of the future cash flows expected to be derived from the D&P assets at June 30, 2021. A recoverable amount of $866.2 million was estimated based on a value in use methodology calculating the estimated discounted cash flows from proved plus probable reserves discounted at a rate of 15% per annum. Commodity prices were based on market prices at June 30, 2021 and were assessed against the forward price curve and pricing forecasts prepared by external firms. As the estimated recoverable amount exceeded the carrying amount of the D&P assets, the maximum available impairment recovery of $19.3 million was recognized in net income.

There are no indicators of impairment at September 30, 2021.

Capitalized Overhead

During the nine months ended September 30, 2021, the Company capitalized $0.8 million of general and administrative costs and $0.1 million of share-based compensation costs directly attributable to acquisition and development activities of certain of its personnel in relation to the Company's operated properties ($0.5 million and $0.1 million, respectively, for the nine months ended September 30, 2020).

Note 6. Accounts Payable and Accrued Liabilities

($ thousands)	**As at September 30, 2021**	**As at December 31, 2020**
Trade payables	17,547	8,579
Accrued liabilities	13,057	8,902
Revenue payable	22,791	10,846
Total	**53,395**	**28,327**

Note 7. Senior Credit Facility

The Company's reserves-based revolving credit facility of US$177.5 million is comprised of a US$167.5 million syndicated facility and a US$10.0 million non-syndicated operating facility (together, the "Senior Credit Facility"). As at September 30, 2021, the net amount drawn under the Senior Credit Facility was US$135.6 million representing US$141.5 million of borrowings under the Senior Credit Facility and US$5.9 million of cash on hand. Advances under the Senior Credit Facility are available by way of direct advances, bankers' acceptances, and standby letters of credit. Direct advances bear interest at the prime rate, US base rate or LIBOR rate, as elected by the Company, plus a margin ranging from 2.0% to 6.0%, which is dependent on the Company's Senior Debt to EBITDA ratio. EBITDA, as defined in the Senior Credit Facility agreement and used for determining the Senior Debt to EBITDA ratio, may be different from Adjusted EBITDA referred to in the Company's other disclosures, including Management's Discussion & Analysis. The Senior Credit Facility is secured by a fixed and floating charge debenture on substantially all the Company's assets.

On April 8, 2021, the Company completed a series of agreements (the "Recapitalization Agreements") with its largest common shareholder, Mr. M. Bruce Chernoff (the Company's Executive Chairman and a director), a company of which Mr. M. Bruce Chernoff is a significant shareholder ("ChernoffCo"), and FR XIII PetroShale Holdings L.P. ("First Reserve" or the "Investor"), the former sole owner of the Company's wholly owned subsidiary's preferred shares and reached an agreement in principle in respect of the Company's credit facility with the Company's bank lending syndicate. Collectively, these agreements fundamentally improved PetroShale's capital structure. The net cash proceeds were applied to the Senior Credit Facility balance. Refer to Note 10 for more discussion of the Recapitalization Agreements.

The Senior Credit Facility borrowing base is subject to redetermination on a periodic basis, based primarily on producing oil and gas reserves, as estimated by the Company's independent third-party engineer, and using commodity prices established by the lender as well as other factors. As part of the Recapitalization Agreements, the lenders to the Senior Credit Facility reaffirmed the borrowing base at US$177.5 million and extended the term-out date to June 25, 2022, at which point, the facility can be extended at the option of the lenders or converted to a one-year term loan. The Company was in compliance with terms of the Senior Credit Facility at September 30, 2021. For the nine months ended September 30, 2021, the effective interest rate on the outstanding borrowings under the Senior Credit Facility was 5.5% (4.4% for the nine months ended September 30, 2020).

Note 8. Decommissioning Obligation

($ thousands)	**Nine months ended September 30, 2021**	**Year ended December 31, 2020**
Beginning of period	6,250	6,313
Additions	594	+
Obligations incurred	-	20
Change in estimated future cash flows	585	(52)
Accretion	89	135
Effect of foreign currency rate changes	19	(166)
End of period	7,537	6,250

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

The Company has estimated the net present value of its total decommissioning provision to be $7.5 million at September 30, 2021 ($6.3 million at December 31, 2020) based on a total undiscounted inflation adjusted liability of $12.4 million ($9.4 million at December 31, 2020). Management estimates that these payments are expected to be made over the next 40 years in accordance with estimates prepared by independent engineers. As at September 30, 2021, a risk-free interest rate of 2.1% (1.7% at December 31, 2020) and an inflation rate of 2.2% (1.4% at December 31, 2020) were used to calculate the present value of the decommissioning obligation.

Note 9. Preferred Shares

($ thousands, except share amounts)	**Number of Shares**	**Liability Component**	**Equity Component**
December 31, 2019	**75,000**	**87,380**	**7,510**
Paid in-kind dividends	-	8,850	-
Accretion	-	2,744	-
Effect of foreign currency rate changes	-	(1,926)	-
December 31, 2020	**75,000**	**97,048**	**7,510**
Paid in-kind dividends	-	6,290	-
Accretion	-	683	-
Loss on modification of preferred shares	-	-	27,400
Conversion of preferred shares to common shares	(75,000)	(102,752)	(34,910)
Effect of foreign currency rate changes	-	(1,269)	-
September 30, 2021	**-**	**-**	**-**

In January 2018, the Company's wholly owned subsidiary (the "Subsidiary Issuer") issued 75,000 preferred shares to First Reserve (the "Investor") at a price of US$1,000 per share for gross proceeds of US$75 million. The preferred shares had a maturity date of January 25, 2023, which could be extended at the option of the Investor by one year. The preferred shares entitled the Investor to a cumulative annual dividend of 9.0% per annum, payable quarterly. The preferred share agreement allowed the Company to elect to pay-in-kind two quarterly dividend payments per twelve-month period subject to a cumulative limit of six quarterly dividend payments over the term of the preferred shares and only following the first anniversary of the issuance date. In September 2020, the preferred share agreement was modified to remove the limitation on the number of paid-in-kind elections in any twelve-month period. Any paid-in-kind dividend payments accrue at a rate of 12.0% per annum and are added to the issuance amount of the preferred shares to determine the redemption obligation at maturity or the amount which may be converted to common shares at the option of the Investor. The Company elected to pay its preferred share dividends due in May 2020, August 2020, November 2020, February 2021, and March 2021 in kind.

The preferred shares were convertible at the discretion of the Investor, in whole or in part, into common voting shares of the Company at a price of $2.40 per share and using an exchange rate of C$1.00 = US$0.795, following the first anniversary of the issuance date. Pursuant to the Recapitalization Agreements (see Notes 7 and 10), the Company and the Investor agreed to revise the exchange price from $2.40 per share to $0.60 per share and all preferred shares were converted to common shares at the amended exchange price. As a result of the conversion of the preferred shares to common shares, all corresponding preferred share liabilities were reclassified to common share capital, and the preferred share equity component was recategorized to common share capital.

The Company recognized a $27.4 million non-cash loss on modification of preferred shares in the Consolidated Statements of Operations and Comprehensive Income (Loss) for the nine-month period ended September 30, 2021. The loss is representative of the difference between the originally prescribed exchange price of $2.40 per share and the subsequently agreed upon exchange price of $0.60 per share, in respect of the number of common shares to be issues on conversion, using a common share valuation as of March 30, 2021.

Note 10. Share Capital

Recapitalization Agreements

On April 8, 2021, the Company concluded the Recapitalization Agreements, which provided for an equity infusion and a recapitalization of the Company as noted in the events highlighted below:

- The Company completed a rights offering (the "Rights Offering") with its current shareholders by issuing to holders of the outstanding common shares of record at the close of business on March 11, 2021 rights to subscribe for additional common shares at $0.20 per share. Upon closing of the Rights Offering on April 8, 2021, PetroShale issued a total of 29,252,965 common shares at a price of $0.20 per share, raising proceeds from the Rights Offering of approximately $5.9 million.
- In lieu of participating in the Rights Offering, ChernoffCo acquired 70,747,035 common shares for aggregate subscription proceeds of $14.1 million via a private placement at $0.20 per common share which closed concurrently with the Rights Offering.
- In lieu of participating in the Rights Offering, First Reserve acquired 50,000,000 common shares for aggregate subscription proceeds of $10.0 million via a private placement at $0.20 per common share concurrently with the Rights Offering.
- All Preferred Shares, held by First Reserve, were exchanged for 182,275,798 common shares at the previously agreed exchange rate of C$1.00 = US$0.795 and a revised price of $0.60 per share. All special voting shares held by First Reserve were cancelled.
- The Company raised a combined $30.0 million of equity via the Rights Offering, the ChernoffCo private placement, and the First Reserve private placement.

As at September 30, 2021, the derecognition of the adjusted carrying value of the preferred share obligation and the equity conversion feature were recorded to shareholders' equity within common shares.

Common Shares

The Company's authorized share capital consists of unlimited voting common shares, unlimited non-voting common shares, and unlimited Class A preferred shares, convertible into voting common shares on one for one basis. As at September 30, 2021, the Company had 521,032,038 voting common shares (188,528,453 at December 31, 2020), no non-voting common shares, and no special voting preferred shares outstanding (42,953,105 at December 31, 2020). The special voting preferred shares were issued in conjunction with the preferred shares issued by the Subsidiary Issuer in January 2018 as well as in connection with the Company's election to pay its preferred share dividends in kind (see Note 9). The special voting preferred shares issued to the Investor entitled the Investor to the "as-exchanged" voting rights of the preferred shares but no other redemption or distribution rights and no claims on the Company's assets. The special voting preferred shares were subsequently cancelled, and all preferred shares (see Note 9) were exchanged for 182,275,798 common shares in concurrence with the Recapitalization Agreements.

The following table reflects the Company's outstanding common shares as at September 30, 2021:

($ thousands, except share amounts)	**Common Shares**	**Share Capital**
December 31, 2019	**191,185,628**	**200,630**
Purchase of common shares for cancellation	(3,865,000)	(1,859)
Settlement of restricted share bonus awards	1,207,825	154
December 31, 2020	**188,528,453**	**198,925**
Settlement of restricted and performance share bonus awards	27,787	7
Settlement of stock options	200,000	39
Recapitalization agreement	332,275,798	166,933
September 30, 2021	**521,032,038**	**365,904**

The Company was previously authorized by the TSX Venture Exchange to commence in a normal course issuer bid ("NCIB"). During the quarter ended March 31, 2020, the Company purchased and cancelled 3,851,500 shares at an average price of $0.48 per common share for a total repurchase cost of $1.9 million under the NCIB. The NCIB expired on Feb 8, 2021 and was not renewed.

Stock Options

The following table presents stock option transactions for the nine months ended September 30, 2021 and year ended December 31, 2020:

	Number of Options	**Weighted Average Exercise Price**	**Weighted Average Remaining Contractual Term (Years)**
December 31, 2019	**550,000**	**0.70**	**1.55**
Exercised	-	-	-
December 31, 2020	**550,000**	**0.70**	**0.55**
Granted	200,000	0.20	-
Exercised	(200,000)	0.20	-
Expired	(550,000)	0.70	-
September 30, 2021	-	-	-

Share Bonus Awards

The Company has granted restricted share bonus awards and performance share bonus awards (collectively, the "share bonus awards") to certain directors, officers, and employees. Share bonus awards granted according to the plan vest over three years from the date of grant and expire before the end of the third year from the date of grant. Performance share bonus awards also vest based on achievement of certain performance hurdles and are subject to a multiplier between 0 and 2.0 times based on relative performance. The share bonus awards may be settled by the Company, in its sole discretion, in cash and or common shares of the Company. The estimated fair value of the share bonus awards is determined based on the current market value of the Company's common shares at the dates of grant and considering anticipated forfeiture rates. For purposes of valuing performance share bonus awards, the Company assumes a multiplier of 1.0 times. A charge to income is reflected as share-based compensation expense in the consolidated statement of operations over the vesting period with a corresponding increase to contributed surplus.

	Restricted Share Bonus Awards	Performance Share Bonus Awards	Total Awards	Estimated Fair Value Price ($)
December 31, 2019	**2,412,968**	**590,200**	**3,003,168**	**1.46**
Granted	3,604,300	4,854,200	8,458,500	0.15
Settled	(2,044,047)	(96,603)	(2,140,650)	(0.80)
Forfeited and expired	(672,194)	(1,105,057)	(1,777,251)	(0.48)
December 31, 2020	**3,301,027**	**4,242,740**	**7,543,767**	**0.41**
Granted	1,778,571	5,554,853	7,333,424	0.20
Settled	(50,000)	-	(50,000)	(2.00)
Forfeited and expired	(61,396)	(70,036)	(131,432)	(0.20)
September 30, 2021	**4,968,202**	**9,727,557**	**14,695,759**	**0.30**

Note 11. Revenue

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

	Three months ended September 30,		**Nine months ended September 30,**	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Petroleum and natural gas	68,198	32,928	156,457	106,238

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

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

Note 12. Net Income (Loss) per Common Share

	Three months ended September 30,		**Nine months ended September 30,**	
($ thousands, except share and per share amounts)	**2021**	**2020**	**2021**	**2020**
Net income (loss)	14,954	(9,134)	(25,893)	(49,568)
Weighted average common shares outstanding - basic	521,032,038	187,803,375	401,671,289	188,117,408
Weighted average common shares outstanding - diluted	535,727,797	195,913,542	416,367,048	196,227,575
Net income (loss) per share - basic	0.03	(0.05)	(0.06)	(0.26)
Net income (loss) per share – diluted	0.03	(0.05)	(0.06)	(0.26)

For purposes of the net income (loss) per share calculation, the preferred shares and stock options are not considered dilutive for the nine-month period ended September 30, 2021 and the three and nine months ended September 30, 2020. On April 8, 2021, in association with the Recapitalization Agreements, the preferred shares were converted to common shares. See Notes 9 and 10.

Note 13. Finance Expense

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2021**	**2020**	**2021**	**2020**
Preferred share dividends	-	3,157	4,171	8,612
Senior credit facility interest	3,117	2,811	8,391	7,393
Preferred share accretion, net	-	575	683	2,069
Decommissioning obligation accretion	45	25	89	110
Operating lease and other	22	33	73	673
Total finance expense	**3,184**	**6,601**	**13,407**	**18,857**

Note 14. Commitments

The Company has two outstanding letters of credit. A US$158,000 letter of credit was issued in the third quarter of 2021 for the benefit of the Office of Natural Resources Revenue pending completion of audit procedures. A second letter is in favor of the energy regulator in North Dakota in the amount of US$75,000. As security, the Company has set aside an equivalent amount in cash at the financial institution that issued the letter of credit. In addition, the Company has advanced funds to other regulatory agencies in the amount of US$160,000 as security to operate in North Dakota. These funds are held as restricted cash in the Interim Consolidated Statements of Financial Position.

Note 15. Financial Instruments and Risk Management

Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable, senior credit facility, financial derivative assets and liabilities, and lease liabilities. Financial derivatives are measured at fair value through profit or loss. The Company's remaining financial instruments are measured at amortized cost. The fair value of cash and cash equivalents, accounts receivable, restricted cash, accounts payable and lease liabilities approximate their carrying amount due to the highly liquid or short-term nature of these instruments. The fair value of the senior credit facility approximates the carrying amount due the floating rate of interest and the margin charged by the lending syndicate being indicative of current spreads.

The following table summarizes the Company's financial instruments that are carried at fair value as a financial derivative liability on the consolidated statements of financial position:

($ thousands)	**As at September 30, 2021**	**As at December 31, 2020**
Fixed price swaps	4,455	-
Three-way Collars	18,454	10,020
Costless Collars	10,064	-
Total	**32,973**	**10,020**

Derivatives and Hedging Activity

The Company's commodity derivative financial instruments are measured at fair value and are included in the statements of financial position as financial derivative assets or liabilities. Unrealized gains and losses are recorded based on the changes in the fair values of the derivative instruments. Both the unrealized and realized gains and losses resulting from the contract settlement of derivatives are recorded in the statement of operations.

The amount of unrealized loss recognized in the consolidated statement of operations related to the Company's derivative financial instruments was $22.5 million for the nine months ended September 30, 2021 ($3.5 million unrealized loss for the nine months ended September 30, 2020). As at September 30, 2021, the Company's derivative instruments consisted of the following types of instruments:

Costless Collars / Three-way collars: Costless collars consist of a fixed floor price (purchased put option) and a fixed ceiling price (sold call option). If the market price is between the floor and the ceiling, no payments are due from either party. At the time of settlement, if the market price exceeds the ceiling or falls below the floor, we receive the fixed price and pay the market price. Three-way collars combine a costless collar with a sold put option below the purchased put option in exchange for a more favorable ceiling price. Under a three-way collar, our downside protection is limited to the difference between the floor price and the strike price of the sold put option.

Fixed price swaps: Under a fixed price swap, the Company receives a fixed price and pays a floating market price to the counterparty.

As at September 30, 2021, the Company had various oil and natural gas price derivative contracts outstanding. The tables below represent the weighted average price for each contract type by fiscal quarter for oil and gas derivative contracts, respectively:

Oil Contract Type	Quarter	Volume (Bbls/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Three-way collars						
	Q4 2021	5,500	-	24.55	38.23	47.34
Costless collars						
	Q1 2022	2,250	-	-	46.22	60.92
	Q2 2022	2,500	-	-	47.10	60.53
	Q3 2022	1,250	-	-	48.00	62.76
	Q4 2022	1,250	-	-	48.00	62.76
Fixed swaps						
	Q1 2022	1,118	56.85	-	-	-
	Q2 2022	833	58.63	-	-	-
	Q3 2022	417	62.78	-	-	-
	Q4 2022	317	62.78	-	-	-

Natural Gas Contract Type	Quarter	Volume (MMbtu/d)	Swap (US$)	Sold Put (US$)	Bought Put (US$)	Sold Call (US$)
Fixed swaps						
	Q1 2022	2,000	3.43	-	-	-
	Q2 2022	2,000	3.43	-	-	-
	Q3 2022	2,000	3.43	-	-	-

Risk Management Activities

Commodity Price Risk

PetroShale may use financial derivative instruments such as swaps, collars, and options to mitigate the impact of commodity price volatility and enhance the predictability of cash flows for a portion of its future oil, gas, and natural gas liquids production. The Company does not enter derivative instruments for speculative purposes. While these instruments mitigate the cash flow risk associated with future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices.

Credit and Contract Risk

Credit and contract risk represent the economic loss that PetroShale would suffer if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms.

Essentially all the Company's accounts receivable is from the production of tight oil and shale gas and joint operations receivables. Sales of tight oil and shale gas production from the Company's operated properties are made to large industry purchasers. Joint operations receivables are from participants in the tight oil and shale gas sector and collection of outstanding balances is dependent on industry factors including commodity price fluctuations. The Company has not experienced any material credit losses on the collection of accounts receivable.

The use of financial derivative instruments also exposes the Company to credit and contract risk. The Company has entered into derivative instruments only with counterparties that are also lenders in the Senior Credit Facility and have been deemed an acceptable credit risk. As the Company's counterparties are participants in Senior Credit Facility, which is secured by substantially all assets of the Company, the Company is not required to post collateral.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meets its financial obligations as they become due. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its short-term and long-term financial obligations when due, under both normal and unusual conditions, without incurring unacceptable losses. As at September 30, 2021, the Company had a net working capital deficit (current assets less current liabilities excluding derivatives) of $7.5 million, excluding the current financial derivative liability of $31.4 million. The financial liabilities in the consolidated statement of financial position consist of accounts payable and accrued liabilities, which are all considered due within one year, and the senior credit facility, lease liability, and derivative liability. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities as they come due. The Company prudently manages liquidity by forecasting of its cash flows from operating activities and its available capacity under its revolving credit facilities. The Company's accounts payable and accrued liabilities balance at September 30, 2021 is approximately $53.4 million (December 31, 2020 - $28.3 million). It is the Company's general practice to pay suppliers within 60 days. In association with the Recapitalization Agreements, the Company's senior lenders reaffirmed the existing borrowing capacity and extended the term-out date to June 25, 2022, at which point, the facility can be extended at the option of the lenders or converted to a one-year term loan. In addition, as a result of the Recapitalization Agreements, the Company's preferred shares were converted to common shares of the Company. Refer to Notes 9 and 10.

The following are the contractual maturities of the Company's debt and anticipated timing of settlements of its other financial liabilities at September 30, 2021, including estimated interest and dividend payments:

($ thousands)	**2021**	**2022**	**2023**	**2024**	**2025**	**Contractual Cash Flow**
Accounts payable and accrued liabilities	53,395	-	-	-	-	53,395
Lease liability	127	346	239	260	284	1,256
Senior credit facility (1)	2,301	9,129	183,831	-	-	195,261

(1) Includes future interest expense at the rate of 5.09% being the rate applicable at September 30, 2021 to the currently established maturity date of June 25, 2023.

Interest Rate Risk

PetroShale is exposed to interest rate risk on bank credit facilities to the extent of changes in market interest rates. Based on the Company's floating rate debt position at September 30, 2021, a 1 percent increase or decrease in the interest rate on floating rate debt would amount to an impact on income before tax of $1.5 million for the nine months ended September 30, 2021.

Capital Management

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital expenditure program, which includes expenditures on oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions, including: current economic conditions; the risk characteristics of the Company's petroleum and natural gas assets; the depth of its investment opportunities; current and forecasted net debt levels; current and forecasted commodity prices; and other factors that influence realized commodity prices and funds flow from operations such as quality and basis differential, royalties, operation costs and transportation and processing costs. The Company considers its capital structure to include working capital, any debt, preferred shares, and shareholders' equity. The Company monitors capital based on current funds flow from operations compared to forecasted capital and operating requirements.

In order to maintain or adjust the capital structure, the Company will consider: its forecasted funds flow from operations while attempting to finance an acceptable capital expenditure program which may in the future include acquisition opportunities; the current level of credit available from its lenders; the level of credit that may become available from its lenders as a result of petroleum and natural gas reserve growth; the availability of other sources of debt with different characteristics than bank debt; the sale of assets; limiting the size of the capital expenditure program and new equity if available on favorable terms. Access to any bank credit facility is determined by the lenders and is generally based upon the lenders' borrowing base models which are based upon the Company's petroleum and natural gas reserves.

Note 16. Supplemental Cash Flow Disclosures

Changes in non-cash working capital is comprised of the following:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	**2021**	**2020**	**2021**	**2020**
Source (use) of cash:				
Accounts receivable	(10,711)	(1,547)	(21,195)	36,555
Prepaid expenses and deposits	(259)	(123)	(119)	(290)
Accounts payable and accrued liabilities	17,327	(16,568)	25,068	(68,374)
	6,357	**(18,238)**	**3,754**	**(32,109)**
Related to operating activities	(370)	(8,726)	1,610	13,143
Related to investing activities	6,534	(9,178)	4,424	(47,380)
Accrued interest and unpaid dividends	(16)	87	(2,325)	99
Difference due to foreign exchange	209	(421)	45	2,029
	6,357	**(18,238)**	**3,754**	**(32,109)**
Interest and preferred dividends paid	(3,067)	(2,945)	(8,670)	(10,493)

Note 17. Subsequent Events

There have been no events that have occurred subsequent to September 30, 2021 and through the filing of these interim consolidated financial statements that require disclosure or adjustments in the consolidated financial statements.