UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2018

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___________to _____________

Commission File Number 001-37943

PETROSHARE CORP.
(Exact name of registrant as specified in its charter)

Colorado	**46-1454523**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

9635 Maroon Circle, Suite 400
Englewood, Colorado 80112
(Address of principal executive offices) (Zip Code)

Registrant's telephone number including area code:**(303) 500-1160**

Securities registered pursuant to Section 12(b) of the Act: **None**
Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☒ No ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☒

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference into Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☒

Emerging growth company ☒

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of June 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, there were 18,103,011 shares outstanding and held by non-affiliates of the registrant. The aggregate market value of those shares, based on the closing price of the Company's common stock on the OTCQB on June 29, 2018, was $26,430,396.

On April 2, 2019, there were 28,077,337 shares of the Company's common stock outstanding.

Documents incorporated by reference: None

PETROSHARE CORP.
ANNUAL REPORT ON FORM 10-K
TABLE OF CONTENTS

ADDITIONAL INFORMATION

Descriptions of agreements or other documents in this report are intended as summaries and are not necessarily complete. Please refer to the agreements or other documents filed or incorporated herein by reference as exhibits. Please see Item 15. Exhibits and Financial Statement Schedules at the end of this report for a complete list of those exhibits.

Cautionary Language Regarding Forward-Looking Statements

Please see Cautionary Language Regarding Forward-Looking Statements on page 21 of this report for important information contained herein.

Glossary

Please see page 30 for a glossary of certain terms used in this report.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

Our History and Organization

PetroShare Corp. ("we," "our," "us" or the "Company") is an independent oil and gas company incorporated under the laws of the State of Colorado on September 4, 2012 to investigate, acquire and develop crude oil and natural gas properties in the Rocky Mountain or mid-continent portion of the United States. Since 2016, our operational focus has been in the Wattenberg Field in the Denver-Julesburg Basin, or DJ Basin, in northeast Colorado. We believe the Wattenberg Field is one of the premier, liquids-rich oil and natural gas resource plays in the United States. It contains hydrocarbon-bearing deposits in several formations, including the Niobrara and Codell. The area has produced oil and natural gas since the 1970s and benefits from an established infrastructure and seasoned service providers.

All of our properties are located in Colorado. As of April 3, 2019, we had an interest in 58 gross (24.4 net) productive wells and 31,656 gross (9,687 net) acres of oil and gas properties. As of December 31, 2018, we were producing hydrocarbons at the rate of approximately 2,232 BOE/D. At December 31, 2018, we had an estimated 2,910.7 MBOE of proved developed reserves and 4,414.1 MBOE of proved undeveloped reserves, including reserves associated with properties that we sold in February, 2019. Our net proved reserves at December 31, 2018 were comprised of approximately 60% oil and NGLs (collectively, liquids).

Our strategy to date has been to focus on acquiring and developing crude oil and natural gas properties in those areas we consider as geo-mechanical sweet spots, including the southern-Wattenberg area of the DJ Basin, which we refer to as the Southern Core area. We elected to concentrate on the Southern Core due to the high quality of hydrocarbon-bearing rock and the production from other, nearby wells. The Southern Core area contains the Niobrara and Codell geologic formations, which tend to yield oil-weighted production that remains economic in lower commodity price environments.

During 2018, we completed and brought into production our first operated horizontal wells, located on our Shook Pad in northwest Adams County. See "Recent Developments-Shook Pad," below. In any drilling, we expect that our retained working interest will be determined based upon factors such as level of interest ownership, well costs and geologic and engineering risk. See Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for more information.

In May 2015, in connection with a credit agreement, we entered into a participation agreement with Providence Energy Operators, LLC ("PEO"). PEO is an affiliate of Providence Energy Corp., a privately-held multi-million-dollar acquirer of oil and gas properties throughout the United States. As discussed elsewhere in this report, an affiliate of PEO is a major participant in our principal lender group through which we currently maintain a $25.0 million Secured Credit Facility. PEO is also the beneficial owner of 11.6% of our outstanding common stock. The participation agreement grants PEO the option to acquire up to a 50% interest and participate in any oil and gas development on acreage we obtain within an area of mutual interest (AMI) near our Southern Core area. To date, PEO has exercised its option under the participation agreement or otherwise participated or agreed to participate in all of our acreage acquisitions and drilling operations.

Our executive and administrative offices are currently located at 9635 Maroon Circle, Suite 400, Englewood, Colorado 80112 and we maintain a website at www.petrosharecorp.com. We commenced filing reports under the Securities Exchange Act of 1934, as amended, or the Exchange Act, in February 2015, when we completed our initial public offering. You may access and read our public filings through the U.S. Securities and Exchange Commission's, or the SEC's, website at www.sec.gov and on our website at www.petrosharecorp.com.

Recent Developments

Following is a summary of certain significant events to which we have been party since the beginning of 2018:

Shook Pad

During 2018, we completed and placed into production our 14-well Shook pad in Northwest Adams County. The pad, started in 2017, contains 14 mid-length lateral wells and is connected to the White Cliffs pipeline through which we transport hydrocarbons for sale. We own an approximate working interest of 49% in the wells, and our partner PEO owns approximately 49%.

Secured Credit Facility

In December 2017, we completed the first closing of $5.0 million of what ultimately became a $25.0 million Secured Credit Facility, all of which was used to reduce our accounts payable, accrued liabilities and a line of credit. On February 1, 2018, we finalized the Secured Credit Facility with Providence Wattenberg Ltd., a Texas limited partnership and affiliate of PEO, as lender and the administrative agent, and 5NR Wattenberg, LLC, a Texas limited liability company, as lender (collectively, the “Secured Lenders”) pursuant to which the Lenders loaned us and additional $20 million under the Secured Credit Facility. This facility allowed us to partially or fully repay a previously-outstanding line of credit and extend a line of credit that matured in December 2017. The remaining capital was utilized for pipeline construction, drilling and completion activities and additional working capital. As of December 31, 2018, we were in default under the Secured Credit Facility based a violations of certain covenants contained in the Secured Credit Facility. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. The Notice declared that all amounts outstanding were immediately due and payable. See “MANAGEMENT’S DISCUSSION AND ANALYSIS AND RESULTS OF OPERATION”

Our biggest challenge during 2018, and to which we devoted a significant amount of our time and resources during the year and beyond, was our lack of liquidity and capital. To address those challenges, we initiated a series of efforts to improve our working capital position. In addition to the Secured Credit Facility discussed above, we also undertook efforts to sell some of our assets to raise cash. This effort resulted in the sale of our non-operated oil and gas wells, discussed in more detail below.

Non-Operated Sale

On February 27, 2019, we completed the sale of nearly all of our non-operated assets. The assets we sold (collectively, the "Assets") include all non-operated horizontal wells in which we had an interest, as well as the leases on which those wells are located, oil, gas and other hydrocarbons produced from the leases on or after the effective date of sale, related equipment, machinery, fixtures and other personal property, surface rights and contracts. The effective date of the asset sale was January 1, 2019.

The sale does not include any of our interest in the operated wells comprising our Shook Pad. The net purchase price received for the Assets was approximately $15.3 million in cash, net of closing costs, adjustments and broker's fees. The proceeds of the sale were applied by the Secured Lenders to reduce balances owed to them under the terms of the Secured Credit Facility.

Resignation of Directors

On March 22, 2019, we received the resignations of three members of our Board of Directors: Michael Allen, Joseph Drysdale and Cullen Schaar. The notices stated that the resignations were effective immediately. These directors had been appointed by the Secured Lenders under the terms of the Secured Credit Facility. None of the directors expressed any disagreement with the Company or its Board of Directors that precipitated the resignations. The Board of Directors plans to continue with a reduced membership of six directors.

Proposed Legislation in Colorado

Recently proposed COLORADO SB-181 ("SB-181"), a state senate bill currently pending in the Colorado legislature, would introduce significant changes to the regulation of oil and gas development in the State. If passed and signed by the governor, it would change the mandate of the Colorado Oil and Gas Conservation Commission ("COGCC") from that of promoting development of oil and gas to prioritizing the protection of public safety, health, welfare, and the environment. In addition to changing the mandate of the COGCC, it would change the composition of the Commission to include more health and safety advocates. The proposed legislation would also allow for more local control over the development of oil and gas properties and could alter the State statute allowing for "forced pooling" of oil and gas properties. This proposed legislation could significantly impact our ability to obtain permits to drill. See "Regulatory Environment" for additional information regarding this proposed legislation.

On March 20, 2019, the Adams County commissioners voted to place a six-month moratorium on the issuance of drilling permits in unincorporated portions of the County due to the pendency of proposed SB-181. A significant portion of our properties are located in Adams County, although some of the properties are located within the limits of the City of Brighton. It is not yet clear whether municipalities like Brighton will follow Adams County and consider a moratorium while the SB 191 is pending.

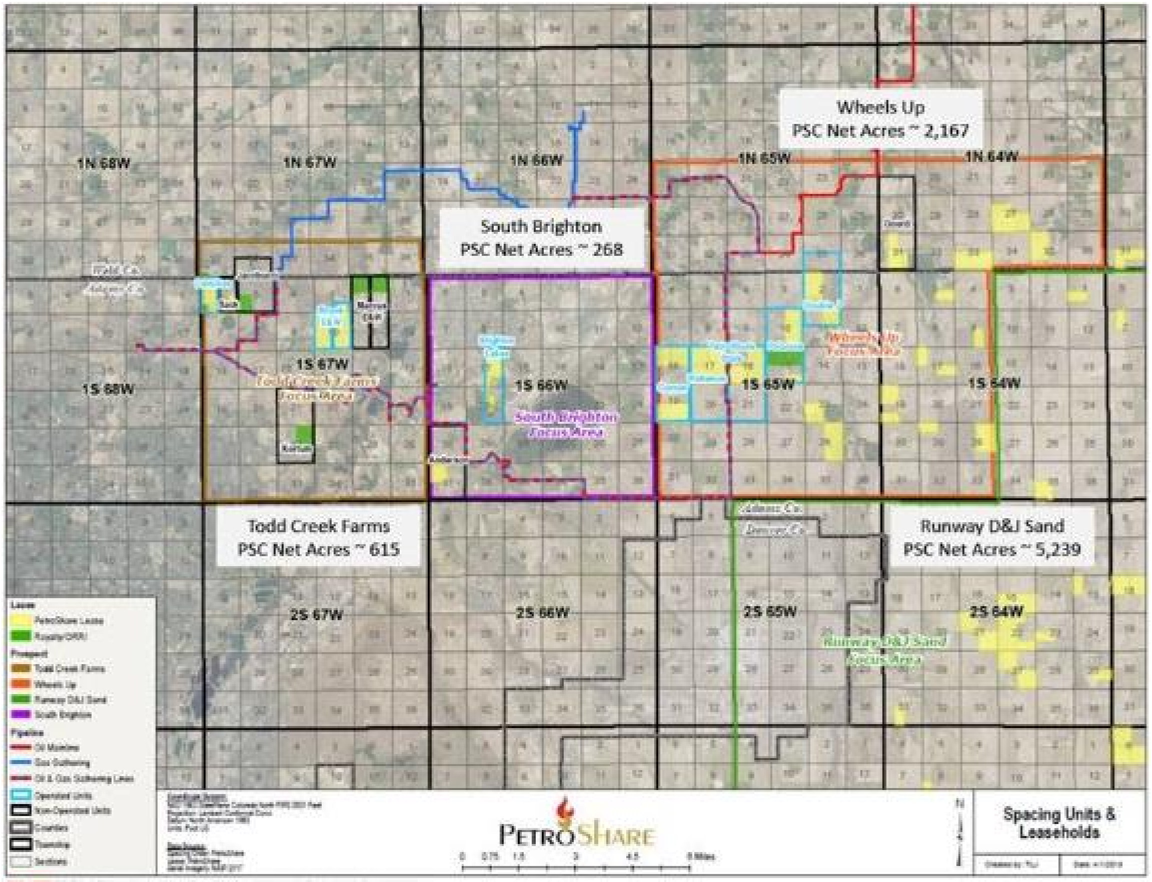
Oil and Gas Properties

DJ Basin and Wattenberg (Southern Core Area)

Our area of focus, the Southern Core Area, is located within the Wattenberg Field, which is a part of the DJ Basin. Discovered in 1970, and historically a gas field, the Wattenberg Field, which covers more than 2,000 square miles, now produces both crude oil and natural gas primarily from the Niobrara and Codell formations. The DJ Basin generally extends from the Denver metropolitan area throughout northeast Colorado into parts of Wyoming, Nebraska, and Kansas. The majority of the DJ Basin lies in Weld County, but reaches into Adams, Arapahoe, Boulder, Broomfield, Denver, and Larimer Counties.

The Southern Core Area covers areas in northwest Adams County and southwest Weld County. The Southern Core Area saw significant development through vertical drilling in the preceding decades, but modern horizontal drilling is relatively new for the area. The "northern core Wattenberg," located south of Greeley in west-central Weld County, has been the primary focus of oil and gas producers for the past seven years. We believe the Southern Core area provides us compelling economics in even lower price environments.

The following map depicts our properties in the Southern Core:



We currently possess an inventory of approximately 88 gross wells that are permitted or pending final permit approval for horizontal drilling locations within our Southern Core Area. Of that amount, there are 56 locations that are fully permitted and available for drilling, subject to available capital. There are a number of remaining locations which are potential infill horizontal wells located in and around current drilling spacing units established under applicable industry rules. We have not included certain of these potential infill horizontal drilling locations in our proved undeveloped or probable reserves because we have not yet established a development plan for those locations in accordance with SEC rules.

Todd Creek Farms

Within our Southern Core focus area, our primary prospect is Todd Creek Farms, which is located in northwest Adams County, Colorado. Our Shook pad, on which we have 14 producing horizontal wells, is located in the Todd Creek focus area. We have also permitted eights wells on the Corcilius pad located within this focus area, however, our plans to drill and complete the Corcilius wells in 2019 are dependent on receiving final approval from Adams County and our availability of capital. Our working interest in the Shook pad wells averages approximately 49%. The Shook Pad and its associated production represent a significant portion of our cash flow in 2018 and 2019 to date.

On February 27, 2019, we completed the sale of essentially all of our non-operated production and proven undeveloped locations in the Todd Creek Farms area. The non-operated wells and associated production provided a significant portion of our cash flow during 2018 prior to our bringing online our operated Shook production in the fourth quarter of 2018.

Wheels Up (aka South Brighton)

Our Wheels Up Area (formerly the South Brighton Focus Area) is east of our Todd Creek Farms prospect and sits in northern Adams County and southern Weld County. We acquired the majority of this acreage in 2016. In 2018, we completed acreage swaps and acquisitions with certain third parties to increase our leasehold interest to approximately 2,166 net acres with the right to acquire another 754 net acres under certain terms and conditions.

During 2018, we received state approved drilling permits as the operator for up to 56 (2 mile) horizontal wells with another 16 horizontal wells targeting the Niobrara and the Codell formations pending final state approval. In addition, we have eight (2 mile) horizontal well permits approved by the state for our Brighton Lakes Pad which we plan to drill in 2019, subject to receiving final approval from the City of Brighton and the availability of capital.

Runway

Our Runway prospect area is east of our Todd Creek Farms and our Wheels Up areas and lies principally within Adams County, Colorado, east of the Denver International Airport. We have leaseholds encompassing 20,118 gross (5,239 net) acres in the Runway prospect.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned a working interest as of April 2, 2019:

	Productive Wells (1)					
	Crude Oil		Natural Gas		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Southern Core	54	23.24	4.0	1.12	58	24.36
Total productive wells	54	23.24	4.0	1.12	58	24.36

(1) The total wells in which we have an interest include 14 gross (6.95 net) horizontal wells on the Shook pad. The remaining wells are vertical wells, some of which are currently or periodically shut-in.

Developed and Undeveloped Acreage

The following table shows our developed and undeveloped acreage as of April 2, 2019:

			Acreage			
	Developed		Undeveloped (1)		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Todd Creek Farms	2,016	615	—	—	2,016	615
Wheels up	4,312	1,840	947	327	5,259	2,167
Northern Wattenberg	80	32	2,036	803	2,116	835
South Brighton	—	—	549	268	549	268
Runway	12,284	4,400	7,834	839	20,118	5,239
Total acreage	18,692	6,887	11,366	2,237	30,058	9,124

(1) Undeveloped acreage includes leasehold interests on which wells have not been drilled or completed to the point that would permit the production of commercial quantities of oil and natural gas regardless of whether the leasehold interest is classified as containing proved reserves.

Following industry standard, we generally acquire oil and gas leases without warranty of title, except as to claims made by, through, or under the transferor. Accordingly, we conduct due diligence as to title prior to acquiring properties, but we cannot guarantee that there will not be losses resulting from title defects. We obtain drilling title opinions and perform any necessary curative work prior to commencing drilling operations. We believe the leasehold title to our properties is good and defensible in accordance with industry standards, subject to such exceptions that, in our opinion, are not so material as to detract from the use or value of our properties. Title to our properties generally carry encumbrances, such as royalties, overriding royalties, contractual obligations, liens, easements, and other matters that commonly affect real property, all of which are customary in the oil and gas industry. We intend to acquire any additional leases by lease purchase, farm-in, or exchange.

Leases that are held by production generally remain in force so long as the well on the particular lease is producing or capable of producing. Leased acres that are not held by production may require annual rental payments to maintain the lease until the expiration of the lease or the time oil or gas is produced from one or more wells drilled on the leased acreage. At the time the well begins producing or is capable of producing, the lease is considered to be held by production. Unless production is established within the area covering our undeveloped acreage, the leases for such acreage eventually will expire. Our leases which are not held by production are scheduled to expire, including potential extensions, from 2019 until 2022. If our leases expire in an area we intend to explore, we or our working interest partners will have to negotiate the price and terms of lease renewals with the lessors. The cost to renew such leases may increase significantly and we may not be able to renew the lease on commercially reasonable terms, or at all.

The following table shows the calendar years during which our leases not currently held by production will expire unless a productive oil or gas well is drilled:

Leased Acres		Expiration of
Gross	Net	Lease
3,428	1,005	2019
7,020	759	2020
579	299	2021
339	174	2022

Drilling Results

The following table sets forth information with respect to the number of wells either drilled by us or in which we participated as a non-operator during the three years ended December 31, 2018. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value.

	For the Year Ended December 31,					
	2018(2)		2017(1)		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	28	8.4	21	2.95	—	—
Dry	—	—	—	—	—	—
Exploratory Wells						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total Wells						
Productive	28	8.4	21	2.95	—	—
Dry	—	—	—	—	—	—

(1) Includes 21 non-operated wells, all of which were sold subsequent to December 31, 2018.

(2) The 2018 results do not include 3 gross (0.2 net) wells which were in the process of drilling or completion as of December 31, 2018.

Sales Data

The following table shows the net sales volumes, average sales prices, and average production costs for wells in which we had an interest during the periods presented:

	Year Ended December 31,		
	2018	2017	2016
Sales volumes			
Oil (Bbls)	287,984	188,529	4,903
Gas (Mcf)	773,396	549,846	26,059
NGLs (Bbls)	55,811	50,111	1,511
BOE	472,694	330,281	10,756
Average sales price			
Oil (per Bbl)	$ 58.37	$ 46.25	$ 48.91
Gas (per Mcf)	$ 3.18	$ 2.78	$ 2.62
NGLs (per Bbl)	$ 20.39	$ 17.20	$ 16.55
BOE	$ 43.17	$ 33.63	$ 30.97
Average production cost per BOE(1)	$ 5.65	$ 2.95	$ 19.18

(1) Excludes production taxes - Total operating cost per BOE for 2018, 2017 and 2016 including production taxes amounted to $8.77, $5.19, and $19.21.

Oil, Natural Gas and NGL Data

Proved Reserves

Estimation of Proved Reserves

Under SEC rules, proved reserves are those quantities of oil, natural gas and NGL, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2018 and 2017 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil, natural gas and NGL reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, Cawley Gillespie & Associates, Inc. ("Cawley Gillespie") considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

Summary of Oil, Natural Gas and NGL Reserves

The table below presents summary information with respect to the estimates of our net proved oil, natural gas and natural gas liquids reserves at December 31, 2018, all of which are located in Colorado, based on a reserve report prepared by Cawley Gillespie dated March 4, 2019.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	MBOE
Proved Developed Producing	1,188	6,300.1	672.7	2,910.7
Proved Developed Non-Producing	-	-	-	-
Proved Undeveloped Reserves	2,005.2	11,232.6	536.8	4,414.1
Total Proved Reserves	3,193.1	17,532.7	1,209.6	7,324.8

At December 31, 2018, we had estimated total proved reserves of 7,324.8 MBOE, consisting of 3,193.1 MBbls of crude oil, 17,532.7 MMcf of natural gas, and 1,209.6 MBbls of natural gas liquids. We sold approximately 47% of our proved reserves in our non-operated properties that closed on February 27, 2019. Our proved reserves include only those amounts that we reasonably expect to recover in the future from known oil and gas reservoirs under existing economic and operating conditions, at current prices and costs, under existing regulatory practices, and with existing technology and anticipated capital resources. Accordingly, any changes in prices, operating and development costs, regulations, technology, or other factors could significantly increase or decrease estimates of our proved reserves. Estimates of volumes of proved reserves are presented in MBbls for crude oil and MMcf for natural gas at the official temperature and pressure basis of the areas in which the gas reserves are located.

Proved Developed Reserves and Proved Undeveloped Reserves

At December 31, 2018, we had 2,910.7 MBOE of estimated proved developed reserves. Proved developed reserves are the proved reserves that can be produced through existing wells with existing equipment and infrastructure and operating methods.

At December 31, 2018, we had 4,414.1 MBOE of estimated proved undeveloped reserves. We have included in our proved undeveloped reserves only those locations for which we have established a development plan and believe we can drill and complete within five years of the date the proved undeveloped reserves were first included in our proved reserves considering our existing and anticipated capital resources. We also have included certain non-operated properties the operator of which has informed us of planned development within the next five years and in which we have plans to participate.

The table below presents summary information with respect to the changes in our proved undeveloped reserves for the year ended December 31, 2018:

	Total (MBOE)
Total proved undeveloped reserves:	
Beginning of year	6,310.8
Revisions of previous estimates	570.9
Additions from discoveries, extensions and infill	69.7
Sales of reserves	(324.0)
Purchases of minerals in place	-
Removed for five-year rule	-
Conversions to proved developed	(2,213.3)
End of year	4,414.1

During 2018 we successfully converted 35% of our proved undeveloped reserves into proved developed producing reserves. The majority of the conversions were associated with the 14 operated wells known as the Shook wells, which were completed during the year. In addition, 21 non-operated PUD locations were developed by third parties, including 18 Ocho locations and 3 B-Farm locations. In total, we reported 94 unique PUD locations as of December 31, 2017, and converted 35 of them into developed properties during 2018. We incurred capital expenditures of approximately $29.3 million to develop these reserves.

The positive revision in previous estimates was primarily the impact of revised drilling plans from other working interest owners on wells operated by them, including the Marcus, Kortum, and Seltzer locations. Substantially all the non-operated PUD locations were sold subsequent to year-end. As of December 31, 2018, we included 70 unique locations in our PUD development plan. As a result of the working capital and liquidity issues encountered during 2018, we reduced our drilling plans during the five-year development window based upon expected capital resources.

Independent Reserve Engineers

Our proved reserves estimate as of December 31, 2018, shown herein, has been independently prepared by Cawley Gillespie, which was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Zane Meekins was the technical person within Cawley Gillespie primarily responsible for preparing the estimates shown herein. Mr. Meekins has been practicing consulting petroleum engineering at Cawley Gillespie since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has approximately 31 years of practical experience in petroleum engineering, with approximately 29 years in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a B.S. in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The report of Cawley Gillespie, dated March 4, 2019, which contains further discussions of the reserve estimates and evaluations prepared by Cawley Gillespie, as well as the qualifications of Cawley Gillespie's technical personnel responsible for overseeing such estimates and evaluations, is attached as Exhibit 99.1 to this report.

Internal Controls Over Reserve Estimation Process

Our President, Frederick J. Witsell, and our Chief Operating Officer, William B. Lloyd, work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve estimation process and are the technical persons within our company primarily responsible for overseeing the preparation of our reserve estimates. Each of Mr. Witsell and Mr. Lloyd has over 37 years of industry experience. Both have evaluated numerous properties throughout the United States with an emphasis on Colorado oil and natural gas production, as well as conventional and unconventional reservoirs, operations, reservoir development and property evaluation. Mr. Witsell holds a B.S. in Geology, an M.B.A. in Energy Management, and is an active member in the Society of Petroleum Engineers, American Association of Petroleum Geologists, and the Rocky Mountain Association of Geologists. Mr. Lloyd holds a B.S. in Petroleum Engineering.

During relevant time periods, Mr. Witsell and Mr. Lloyd meet with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserve estimates. We do not have a formal committee specifically designated to review our reserve reporting and our reserve estimation process. A preliminary copy of the reserve report was reviewed by Mr. Witsell with representatives of our independent reserve engineers and internal technical staff.

Operations

General

We had an interest in both operated and non-operated properties during the year ended December 31, 2018. However, we sold all of our non-operated properties in February 2019, with an effective date of January 1, 2019.

As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We sell the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices. Our largest purchaser is an oil marketer who has the ability to sell production into multiple markets.

During the year ended December 31, 2018, approximately 95% of our production was sold to three customers. During the year, approximately 41% of our revenue was derived from sales to Great West Oil and Gas Company, 33% were derived from sales to Rose Rock Midstream Crude LP and 21% were from sales to PDC Energy, Inc.

In connection with sales of oil and other products from our Shook pad, we are substantially dependent on Rocky Mountain Midstream LLC, which owns and operates the pipeline into which we produce oil to be sold to customers. We experienced significant interruptions in production during 2018 and in early 2019 due to operating difficulties with the pipeline, and we expect that such interruptions may occur in the future.

Regulatory Environment

The production and sale of oil and gas is subject to various federal, state, and local governmental regulations, which may be changed from time to time in response to economic or political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, noise, unitization and pooling of properties, setbacks, the location and reclamation of piping, taxation and environmental protection. Many laws and regulations govern the location of wells, the method of drilling, casing and completing wells, the plugging and abandoning of wells, the restoration of properties upon which wells are drilled, temporary storage tank operations, air emissions from flaring, compression, the construction and use of access roads, and the disposal of fluids used in connection with operations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. Changes in these regulations could have a material adverse effect on our company.

The failure to comply with any such laws and regulations can result in substantial penalties. In addition, the effect of all these laws and regulations may limit the amount of oil and gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Although we believe we are in substantial compliance with current applicable laws and regulations relating to our oil and natural gas operations, we are unable to predict the future cost or impact of complying with such laws and regulations because such laws and regulations are frequently amended or reinterpreted.

As an oil and gas operator, we are responsible for obtaining all permits and government permission necessary to drill the wells and develop our interests. We must obtain permits for any new well sites and wells that are drilled.

In February 2014, the Colorado Department of Public Health and Environment's Air Quality Control Commission, or AQCC, finalized regulations imposing stringent new requirements relating to air emissions from oil and gas facilities in Colorado. The new rules impose significantly more stringent control, monitoring, recordkeeping, and reporting requirements than those required under comparable federal rules. In addition, as part of the rule, the AQCC approved the direct regulation of hydrocarbon (i.e., methane) emissions from the Colorado oil and gas sector.

On January 25, 2016, the COGCC approved new rules enhancing local government participation in locating and planning for large scale oil and gas operations. The COGCC defined large scale facilities as (i) any location that proposes eight new horizontal, directional, or vertical wells, or (ii) cumulative hydrocarbon storage capacity of 4,000 Bbls or more, which are located within an urban mitigation area as defined by COGCC rules. The new COGCC rules also include additional notice and consultation requirements for operators when planning such large-scale facilities.

We currently own or lease numerous properties that have been used for the exploration and production of crude oil and natural gas for many years. If hydrocarbons or other wastes have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal by us or prior owners or operators of such properties, we could be subject to liability under the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Federal Resource Conservation and Recovery Act, or RCRA and analogous state laws, as well as state laws governing the management of crude oil and natural gas wastes. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of, transported, or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment or remediation to prevent future contamination and for damages to natural resources. Under state laws, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Hydraulic Fracturing

We operate primarily in the Wattenberg Field of the DJ Basin where the rock formations are typically tight, and it is a common practice to utilize hydraulic fracturing to allow for or increase hydrocarbon production. Hydraulic fracturing involves the process of injecting substances such as water, sand and additives (some proprietary) under pressure into a targeted subsurface formation to create pores and fractures, thus creating a passageway for the release of oil and gas. Hydraulic fracturing is a technique that we have and intend to employ extensively in future wells that we may drill and complete.

We expect to outsource all hydraulic fracturing services to service providers with significant experience, and which we deem to be competent and responsible. Our service providers supply all personnel, equipment, and materials needed to perform such stimulation, including the chemical mixtures that might be injected into our wells. We require our service companies to carry insurance covering incidents that could occur in connection with their activities. In addition to the drilling permit that we are required to obtain and the notice of intent that we provide the appropriate regulatory authorities, our service providers are responsible for obtaining any regulatory permits necessary for them to perform their services in the relevant geographic location. We have not had any incidents, citations, or lawsuits relating to any environmental issues resulting from hydraulic fracturing, and we are not presently aware of any such matters.

In recent years, environmental opposition to hydraulic fracturing has increased, and various governmental and regulatory authorities have adopted or are considering new requirements for this process. To the extent that these requirements increase our costs or restrict our development activities, our business and prospects may be adversely affected.

The United States Environmental Protection Area, or EPA has asserted that the Safe Drinking Water Act ("SDWA") applies to hydraulic fracturing involving diesel fuel, and in February 2014, it issued final guidance on this subject. The guidance defines the term "diesel fuel," describes the permitting requirements that apply under SDWA for the underground injection of diesel fuel in hydraulic fracturing and makes recommendations for permit writers. Although the guidance applies only in those states, excluding Colorado, where the EPA directly implements the Underground Injection Control Class II program, it could encourage state regulatory authorities to adopt permitting and other requirements for hydraulic fracturing. In addition, from time to time, Congress has considered legislation that would provide for broader federal regulation of hydraulic fracturing under the SDWA. If such legislation were enacted, hydraulic fracturing operations could be required to meet additional federal permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and provide for additional public disclosure of the chemicals used in the fracturing process.

The EPA is also conducting a nationwide study into the effects of hydraulic fracturing on drinking water. In June 2015, the EPA released a draft assessment of the potential impacts to drinking water resources from hydraulic fracturing for public comment and peer review. The assessment concluded that while there are mechanisms by which hydraulic fracturing can impact drinking water resources, there was no evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States. The EPA's science advisory board subsequently questioned several elements and conclusions in the EPA's draft assessment. In December 2016, the EPA released the final report on impacts from hydraulic fracturing activities on drinking water, concluding that hydraulic fracturing activities can impact drinking water resources under some circumstances and identified some factors that could influence these impacts.

Federal agencies have also adopted or are considering additional regulation of hydraulic fracturing. On March 26, 2016, the U.S. Occupational Safety and Health Administration ("OSHA") issued a final rule, with effective dates of 2018 and 2021 for the hydraulic fracturing industry, which imposes stricter standards for worker exposure to silica, including worker exposure to sand in hydraulic fracturing. In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. In March 2015, the Bureau of Land Management ("BLM") issued a new rule regulating hydraulic fracturing activities involving federal and tribal lands and minerals, including requirements for chemical disclosure, wellbore integrity and handling of flowback and produced water.

In Colorado, the primary regulator is the COGCC, which has adopted regulations regarding chemical disclosure, pressure monitoring, prior agency notice, emission reduction practices, and offset well setbacks with respect to hydraulic fracturing operations and may in the future adopt additional requirements for this purpose. As part of these requirements, operators must report all chemicals used in hydraulically fracturing a well to a publicly searchable registry website developed and maintained by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

Apart from these ongoing federal and state initiatives, local governments are adopting new requirements and restrictions on hydraulic fracturing and other oil and gas operations. Some local governments in Colorado, for instance, have amended their land use regulations to impose new requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same objective. Beyond that, during the past few years, a total of five Colorado cities have passed initiatives temporarily or permanently prohibiting hydraulic fracturing. Since that time, however, local district courts have struck down the ordinances for certain of those Colorado cities, and such decisions were upheld by the Colorado Supreme Court in May 2016. Nevertheless, there is a continued risk that cities will adopt local ordinances that seek to regulate the time, place, and manner of hydraulic fracturing activities and oil and gas operations within their respective jurisdictions.

Adams County USR Process

On March 22, 2016, the Adams County Board of County Commissioners approved amendments to the county's oil and gas regulatory process. The new regulations include an enhanced administrative review process for operators that share a Memorandum of Understanding, or MOU, with Adams County, including a site-specific review of any oil and gas permit application. The regulations also require compliance with the USR approval process for oil and gas facilities governed by an MOU between the operator and Adams County. This approval process includes increased notice and filing requirements. The USR process is designed to consist of a six-week administrative review of the application by the county and appropriate agencies. The application can be approved, approved with conditions, denied or referred to the Board of County Commissioners for a public hearing. If denied, the applicant can appeal to the Board of County Commissioners.

In March 2019 the Adams County Commissioners imposed a moratorium on new drilling permits within unincorporated areas of the County for a period of six months.

City of Brighton Permitting Process

During a two-year period between 2017 and 2019 we negotiated to obtain a Memorandum of Understanding (MOU) with the City of Brighton. In February 2019 we submitted an oil and gas Pre-Application and participated in a Pre-Application meeting with the City of Brighton. In March 2019 we submitted an oil and gas application for a permit to develop our Brighton Lakes pad. Once submitted, the City of Brighton has 10 days to request edits and additions to the permit. Once deemed complete, the City is required to provide a 14 day notice to neighbors within a 1,000 feet of the parcel and to host a neighborhood informational meeting to discuss questions and concerns. At such time, if all requirements have been met, the City can issue a permit to drill.

Joint Operating Agreements

We are registered with the COGCC as an operator of oil and natural gas wells and properties in the State of Colorado and have posted the appropriate bonds to support our activities. We have entered into operating agreements with our working interest partners that stipulate, among other things, that each partner is responsible for paying its proportionate share of costs and expenses in connection with the wells we operate. As operator, we are an independent contractor not subject to the control or direction of our other working interest partners except as to the type of operation to be undertaken as provided in the operating agreement. Further, we are responsible for hiring employees or contractors to conduct operations, taking custody of funds for the account of all working interest partners, keeping books and records relating to operations, and filing operational notices, reports or applications required to be filed with governmental bodies having jurisdiction over operations. Our liability to the other working interest partners for losses sustained or liabilities incurred are limited to losses incurred as a result of our gross negligence or willful misconduct.

Competition

We encounter significant competition from numerous other oil and gas companies in all areas of operations, including drilling and marketing oil and natural gas; obtaining desirable oil and natural gas leases; obtaining drilling, pumping and other services; attracting and retaining qualified employees; and obtaining capital. International developments may influence other companies to increase their domestic crude oil and natural gas exploration. Competition among companies for favorable prospects can be expected to continue and we anticipate that the cost of acquiring properties will increase in the future. Most of our competitors possess larger staffs and greater financial resources than we do, which will enable them to identify and acquire desirable producing properties and drilling prospects more economically and to attract more capital. Our ability to acquire additional properties and to explore for oil and natural gas prospects in the future depends upon our ability to conduct our operations, raise capital, evaluate and select suitable properties, and consummate transactions in this highly competitive environment.

The oil and gas industry is characterized by rapid and significant technological advancements and introduction of new products and services using new technologies. If one or more of the technologies we use now or in the future become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, results of operations and cash flows could be materially adversely affected.

Employees

We currently have 11 employees, including our Chief Executive Officer, President, Chief Operating Officer, and Chief Financial Officer. We also engage a number of independent contractors and consultants to supplement the services of our employees, including land services, geologic mapping, reservoir and facilities engineers, drilling contractors, attorneys, and accountants.

Company Facilities

Our executive and administrative offices are currently located at 9635 Maroon Circle, Suite 400, Englewood, Colorado 80112, where we lease approximately 5,282 square feet at a rate of $11,224 per month. We consider this space to be adequate for our needs for the foreseeable future.

ITEM 1A. RISK FACTORS

This report, including Management's Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements that may be affected by several risk factors. The following information summarizes the material risks known to us as of the date of filing this report:

Risks Relating To Our Company

As described in the notes to our consolidated financial statements, there is substantial doubt about our ability to continue as a going concern and we are dependent on receipt of additional capital to fund our obligations and to continue in operation.

The uncertainty regarding our ability to continue as a going concern is based on our defaults under the Secured Credit Facility, substantial near-term liabilities, continuing net losses and negative working capital, among other things which existed as of December 31, 2018. At December 31, 2018, we had a cash balance of approximately $2.6 million and other current assets of approximately $29.6 million, including assets held for sale of $16.1 million which were sold subsequent to year-end, resulting in negative working capital of $32.9 million. We had net losses, including non-cash charges, of $17.3 million and $10.8 million for the years ended December 31, 2018 and 2017, respectively. At December 31, 2018 we were obligated to repay $9.4 million in principal plus accrued interest on our outstanding convertible promissory notes, which payment we did not make. We are in default under the terms of our Secured Credit Facility and as a result, we have included $29.9 million including the outstanding principal and accrued interest and penalties in current liabilities. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. The Notice declared that all amounts outstanding were immediately due and payable. Some of our accounts payable obligations to vendors are past the due date and some of those vendors have filed liens or indicated an intent to file liens against certain of our assets. The net proceeds from the sale of our non-operated assets in February 2019 have been applied by our Secured Lenders to reduce amounts allegedly owed under the Secured Credit Facility. We will need to generate sufficient cash flow from operations and sell equity or debt to fund further drilling and acquisition activity and to continue in operation. If sufficient cash flow and additional financing is not available, we may be compelled to reduce the scope of our business activities, sell a portion of our interests in our oil and gas properties or file for bankruptcy protection. This, in turn, may have an adverse effect on our ability to realize the value of our assets. These factors raise substantial doubt about our ability to continue as a going concern and you may lose some or all of your investment.

We have engaged legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives to restructure our indebtedness and we may elect to implement such a restructuring through Chapter 11 of the United States Bankruptcy Code in order to obtain court supervision and to facilitate the stakeholder approvals necessary to implement such a restructuring, or it may otherwise become necessary for us to seek protections under Chapter 11.

Seeking Chapter 11 protection may have a material adverse impact on our business and the trading price of our securities. As long as a Chapter 11 proceeding continues, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization, including managing potential negative impact to our reputation. Bankruptcy court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. Additionally, all of our indebtedness is senior to the existing common stock in our capital structure. As a result, we believe that seeking bankruptcy court protection under a Chapter 11 proceeding could cause the shares of our existing common stock to be canceled, or otherwise result in a limited recovery, if any, for holders of our common stock, and would place holders of our common stock at significant risk of losing some or all of their investment in our shares.

Our secured debt is currently in default and if our effort to negotiate a continuing waiver of that default is unsuccessful, the lenders may foreclose on or force a sale of our assets.

We notified our Secured Lenders in 2018 and 2019 of several events of default under the terms of the Secured Credit Facility, including the filing of liens on our properties, liabilities that were more than 90 days past due and our inability to pay the unsecured notes when they matured at December 31, 2018. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default. As a result of these events, we are in default under the terms of the Secured Credit Facility and as a result all outstanding principal, interest and penalties are immediately due and payable. If we are unable to obtain a waiver of the defaults the lenders may undertake collection efforts against us and our property. In that event, the holders of the debt would likely be entitled to the first proceeds of the sale of our assets and the holders of our equity securities may lose some or all of their investment.

Our use of debt financing could have a material adverse effect on our financial condition.

In addition to the existing defaults under the Secured Credit Facility, we are subject to the risks normally associated with debt financing, including the risk that our cash flow will be insufficient to meet required principal and interest payments and the long-term risk that we will be unable to refinance that indebtedness, or that the terms of such refinancing will not be as favorable as the terms of existing indebtedness. If our debt cannot be paid, refinanced or extended, we may be required to divest our assets or file for bankruptcy. Further, if prevailing interest rates or other factors at the time of a refinancing result in higher interest rates or other restrictive financial covenants, then such refinancing would adversely affect our cash flow and funds available for operation and development of our assets and properties.

We are also subject to financial covenants under the Secured Credit Facility. These covenants generally require us to satisfy certain financial ratios related to our oil and gas reserves and debt to earnings, and prohibit us without the lenders' consent from, among other things, incurring additional indebtedness or making loans to any third party, other than trade debt incurred in the ordinary course of business or selling, leasing, or otherwise disposing of any material amount of assets. Failure to comply with these covenants could result in a further default.

Our estimates of oil and gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and cash flows attributable to such unconventional resource reserves, including factors beyond our reserve engineers' control. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and gas prices, expenditures for future development and exploration activities, engineering and geological interpretations and judgment. In addition, accurately estimating reserves in unconventional resources such as the shale and tight sand formations, of the Niobrara and Codell, can be even more difficult than estimating reserves in more traditional hydrocarbon-bearing formations given the complexities of the projected decline curves and economics of unconventional oil and gas resource wells.

As such, investors should not place undue reliance on these estimates contained in this report. Reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of oil and gas. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Due to our smaller volume of reserves compared to our competitors, revisions in reserve estimates and future cash flows have a greater chance of being material to us.

Legislation pending in the Colorado legislature and a recent permitting moratorium in Adams County may have an adverse effect on our ability to raise capital and develop our oil and gas properties.

The Colorado legislature, the State all of our properties are located in, has proposed legislation that would significantly affect oil and gas development in the state. Among other things, that legislation would revise the mandate of the COGCC from one of primarily fostering oil and gas development to one of ensuring the health, safety and environment of the State's citizens. The proposed legislation, if adopted in its present form, would also revamp the composition of the COGCC to include more health and safety advocates and less industry advocates. In addition, the legislation could allow the COGCC to refuse to issue new permits until final rules are adopted consistent with the new legislation. This legislation is presently making its way through the legislature and there is no assurance that it will be adopted in its present form, or at all. However, if past in some form, the governor of the state has promised to sign the legislation. In response to the proposed legislation, in March, 2019 Adams County has imposed a six-month moratorium on new permits while the legislation is considered. If this legislation is approved in its present form, it could have a significant and adverse effect on oil and gas development in the State, especially on development in proximity to residential and other sensitive areas. This legislation and the Adams County moratorium may also have a chilling effect on our ability to raise capital, as bankers and other investors seek to evaluate the effect of the pending legislation on our properties and future prospects.

We may experience a change in control and our officers and/or directors may be replaced.

It is possible that in connection with a refinancing or other restructuring of our debt to improve our liquidity, we would have to issue additional common stock or new preferred stock and that the issuance of this stock may give the new shareholders control of our board of directors. We are unable to determine at this time who these investors might be or who might be appointed to our board. Investors in our common stock will be unable to evaluate the new directors until such time, if ever, they are formally appointed.

Oil and gas wells are depleting assets and our failure or inability to reinvest in additional wells will lead to reduced production.

Our ability to invest additional amounts in new wells and additional acreage is a function of the availability of capital. If we are unable to obtain that capital in amounts sufficient to allow for additional investment, our existing and contemplated production will eventually diminish. This may lead to a drop in the price of our stock, and investors may lose all or part of their investment.

The due diligence undertaken by us in connection with recent acquisitions may not have revealed all relevant considerations or liabilities related to those assets, which could have a material adverse effect on our financial condition or results of operations.

The due diligence undertaken by us in connection with the acquisition of our properties may not have revealed all relevant facts that may be necessary to evaluate such acquisitions. The information provided to us in connection with our diligence may have been incomplete or inaccurate. As part of the diligence process, we have also made subjective judgments regarding the results of operations and prospects of the assets. If the due diligence investigations have failed to correctly identify material issues and liabilities that may be present, such as title defects or environmental problems, we may incur substantial impairment charges or other losses in the future. In addition, we may be subject to significant, previously undisclosed liabilities that were not identified during the due diligence processes and which may have a material adverse effect on our financial condition or results of operations.

We have granted PEO the option to participate in certain of our acreage acquisitions.

On May 13, 2015, we entered into a participation agreement with PEO which has been amended on two subsequent occasions. Under the terms of the original participation agreement, we assigned an undivided 50% interest to our right, title and interest in our then-existing leases in our Todd Creek Farms prospect and granted PEO the right to acquire up to 50% of other acquisitions within an area of mutual interest, or AMI. The Participation Agreement was subsequently amended to provide an option to another affiliate of PEO, potentially reducing our retained interest in any properties to 50%. The AMI covers all of our Southern Core area and part of our other properties. To date, PEO has exercised its option to participate in all of our acreage acquisitions.

We have limited management and staff and are dependent upon partnering arrangements and third-party service providers.

We currently have 11 employees, including our Chief Executive Officer, President, Chief Financial Officer and Chief Operating Officer. The loss of any of these individuals would have an adverse effect on our business, as we have very limited personnel. We leverage the services of other independent consultants and contractors to perform various professional services, including engineering, oil and gas well planning and supervision, and land, legal, environmental and tax services. We also pursue alliances with partners in the areas of geological and geophysical services and prospect generation, evaluation and prospect leasing. Our dependence on third-party consultants and service providers create a number of risks, including but not limited to:

- the possibility that such third parties may not be available to us as and when needed; and
- the risk that we may not be able to properly control the timing and quality of work conducted with respect to its projects.

If we experience significant delays in obtaining the services of such third parties or they perform poorly, our results of operations and stock price could be materially adversely affected.

The proceeds from the recent sale of all of our non-operated oil and gas assets have been paid to our Secured Lenders and applied to the outstanding balance on our Secured Credit Facility and will not be available to pay any of our vendors or the olders of any other accrued liabilities.

Under the terms of the Secured Credit Facility, we were obligated to obtain the consent of our Secured Lenders to sell the non-operated assets. As a condition of that consent, the Secured Lenders required that the proceeds of the sale be paid to an account controlled by them, and that we grant the Secured Lenders a security interest in the proceeds. Following the sale, the Secured Parties notified us that they had applied the proceeds of the sale against the amounts that they deemed outstanding under the Secured Credit Facility. As a result, we are unable to use those proceeds to pay our vendors or the holders of any other accrued liabilities. Some of those vendors have filed mechanic's liens against our property interests as a result of our failure to pay the amounts due to the vendors. If the amounts due giving rise to those liens are not paid prior to the expiration of the liens, the vendors may foreclose the liens and attempt to sell some of our properties. The vendors may also put us on cash terms for future transactions, severely restricting our ability to conduct business in the ordinary course.

Competition in the oil and natural gas industry is intense and many of our competitors have resources that are substantially greater than ours.

Our industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil, natural gas and NGLs, but also purchase and transport hydrocarbons, carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies are able to attract more capital and pay more for productive properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to raise capital and evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, larger companies have a greater ability to continue exploration activities during periods of low commodity prices. Larger competitors are also able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which could adversely affect our competitive position. These factors could adversely affect the success of our operations and our profitability.

We are concentrated in one geographic area, which increases our exposure to many of the risks enumerated herein.

Operating in a concentrated area increases the potential impact that many of the risks stated herein may have upon our ability to perform. For example, we have greater exposure to regulatory actions impacting Colorado, natural disasters in the geographic area, competition for equipment, services and materials available in the area and access to infrastructure and markets. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the DJ Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our ability to sell any production and/or receive market prices for our production has in the past and may in the future be adversely affected by a lack of transportation, capacity constraints and interruptions.

The marketability of any production from any of our properties depends in part upon the availability, proximity and capacity of third-party refineries, natural gas gathering systems and processing facilities. We currently deliver most of the oil and natural gas produced from our properties through pipelines that we do not own and expect to do so in the future. The availability of delivery capacity in these pipelines is in part dependent on the market price for oil and natural gas, as higher prices will attract additional production, which in turn will take up capacity in these systems. The lack of availability or capacity of these systems and facilities could reduce the price offered for any production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. In addition to capacity constraints, we have been significantly affected by interruptions in operation of these gathering systems and processing facilities and may be affected in the future. Since we do not own these systems, we cannot control their operation.

We are not required to obtain an opinion from our independent registered public accounting firm on the effectiveness of our internal controls over financial reporting under Section 404(b) of the Sarbanes-Oxley Act of 2002 until we are no longer an emerging growth company.

For so long as we remain an emerging growth company as defined in the JOBS Act, we intend to take advantage of certain exemptions from various reporting requirements that are applicable to public companies that are not emerging growth companies, including, but not limited to, not being required to obtain the auditor attestation of our assessment of our internal controls. Once we are no longer an emerging growth company or, if prior to such date, we opt to no longer take advantage of the applicable exemption, we will be required to include an opinion from our independent registered public accounting firm on the effectiveness of our internal controls over financial reporting. We will remain an "emerging growth company" until the earliest to occur of (1) the last day of the fiscal year during which our total annual revenues equal or exceed $1.0 billion (subject to adjustment for inflation), (2) the last day of the fiscal year during which occurs the fifth anniversary of our initial public offering, (3) the date on which we have, during the previous three-year period, issued more than $1.0 billion in non-convertible debt, or (4) the date on which we are deemed a "large accelerated filer" under the Securities Exchange Act of 1934, as amended, or the Exchange Act. Once we are no longer an emerging growth company, compliance with Section 404(b) will be costly.

Colorado law and our Articles of Incorporation may protect our directors from certain types of lawsuits at the expense of the shareholders.

The laws of the State of Colorado provide that directors of a corporation shall not be liable to the corporation or its shareholders for monetary damages for all but limited types of conduct. Our Articles of Incorporation permit us to indemnify our directors and officers against all damages incurred in connection with our business to the fullest extent provided or allowed by law. The exculpation provisions may have the effect of preventing shareholders from recovering damages against our directors caused by their negligence, poor judgment or other circumstances.

Risks Relating to the Energy Production and/or Distribution Industry

Oil and natural gas exploration and development are affected by fluctuations in oil and natural gas prices, and low prices could have a material adverse effect on the future of our business.

In addition to our efforts to raise capital, our future success will depend largely on the prices received for any oil or natural gas production. Prices received also will affect the amount of future cash flow available for capital expenditures and may affect the ability to raise additional capital. Lower prices affect the amount of oil and natural gas that can be commercially produced from reserves either discovered or acquired. Lower prices may also make it uneconomical to drill in certain areas.

The prices for oil and natural gas have been volatile since 2014, with a high over $100.00 per barrel in June 2014 and to lows below $30.00 per barrel in 2016 based on West Texas Intermediate (WTI) Crude Oil, as quoted on NYMEX. Prices for natural gas have also been volatile. On April 2, 2019, the price of WTI was $62.61 per barrel and Henry Hub Natural gas was $2.69 per MMBtu. Our revenue, results of operation, cash flows, liquidity and reserve estimates depend to a large part on the price of oil and gas. Factors that can cause price fluctuations include:

- the level of consumer product demand;
- the domestic and foreign supply of oil and natural gas;
- consumer perception and the availability of alternative energy sources;
- refinery capacity;
- domestic and foreign governmental regulations;
- actions by other producers, including the Organization of the Petroleum Exporting Countries (OPEC);
- political and ethnic conflicts in oil and natural gas producing regions;
- the price of foreign imports; and
- overall economic conditions.

If we do not hedge our exposure to reductions in oil and natural gas prices, we may be subject to significant reductions in price. Alternatively, we may use oil and natural gas price hedging contracts, which involve credit risk and may limit future revenues from price increases and result in significant fluctuations in our profitability.

We may use hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use also may limit future revenues from price increases. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations. Alternatively, in the event that we choose not to hedge, our exposure to reductions in oil and natural gas prices by purchasing futures and by using other hedging strategies, we may be subject to significant reduction in prices which could have a material negative impact on our profitability.

We identified locations scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified drilling locations in our operating areas scheduled over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, approval by regulators, seasonal conditions, oil and natural gas prices, assessment of risks, costs and drilling results. The final determination on whether to drill any of these locations will be dependent upon the factors described elsewhere in this report as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Due to these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all. Our actual drilling activities may be materially different from our current expectations, which could adversely affect our business, financial condition and results of operations.

We may face difficulties in securing and operating under authorizations and permits to drill, complete or operate our wells.

Oil and gas exploration in the United States has drawn intense scrutiny from environmental and community interest groups, regulatory agencies and other governmental entities. As a result, we may face significant opposition to, or increased regulation of, our operations that may make it difficult or impossible to obtain permits and other needed authorizations to drill, complete or operate, result in operational delays, or otherwise make oil and gas exploration more costly or difficult than in other countries.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute exploration and development plans within the established budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations. Increased drilling or completion costs may not be fully offset by increases in the price received for oil and gas.

Our operations are subject to health, safety and environmental laws and regulations which may expose us to significant costs and liabilities, and which may not be covered by insurance.

Our oil and natural gas exploration is subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment and the protection of the environment. These laws and regulations impose on our operations numerous requirements, including the obligation to obtain a permit before conducting drilling activities; restrictions on the types, quantities and concentration of materials that may be released into the environment; limitations or prohibitions of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; specific health and safety criteria to protect workers; and the responsibility for cleaning up any pollution resulting from operations. Numerous governmental authorities such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our proposed operations; and delays in granting permits or cancellation of leases.

Under certain environmental laws and regulations, we may be liable regardless of whether we were at fault for the full cost of removing or remediating contamination, even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws. In addition, accidental spills or releases on our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations, and which may not be covered by insurance. Aside from government agencies, the owners of properties where our wells are located, the operators of facilities where our petroleum hydrocarbons or wastes are expected to be taken for reclamation or disposal and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations or obtain damages for any related personal injury or property damage. Some sites are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, emission, waste management or cleanup requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

Federal, state, and local legislative and regulatory initiatives relating to oil and gas production, including hydraulic fracturing, as well as government reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production and/or ability to book future reserves.

Hydraulic fracturing involves the injection of water, sand or other proppants, and chemical additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the proppant, enabling the oil or natural gas to flow to the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel fuel under the Safe Drinking Water Act. In addition, the COGCC has adopted (and other states have adopted or are considering adopting) regulations that impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. Further, on February 23, 2014, Colorado's Air Quality Control Commission fully adopted EPA's Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution; adopted corresponding revisions to its emissions reporting and permitting framework; and adopted complimentary oil and gas control measures. These regulations will affect our operations, increase our costs of exploration and production and limit the quantity of oil and natural gas that we can economically produce to the extent that we use hydraulic fracturing.

Effective March 22, 2016, Adams County adopted new amendments to the county's oil and gas regulatory process. The new regulations include an enhanced administrative review process, which may increase our costs or delay our drilling program.

In the event that additional regulations or legal restrictions at the federal, state or local level are adopted related to oil and gas production, hydraulic fracturing or other development activities in the areas in which we currently or in the future plan to operate, we may incur additional costs to comply with such requirements that may be significant in nature, and also could become subject to additional permitting and siting requirements and cause us to experience added delays or curtailment in the pursuit of exploration, development, or production activities. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases," or GHG, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States on an annual basis, including petroleum refineries, as well as certain onshore oil and natural gas production facilities.

On March 10, 2016, the EPA announced that it is moving towards issuing performance standards for methane emissions from existing oil and gas sources. The agency said that it will "begin with a formal process (*i.e.*, an Information Collection Request) to require companies operating existing oil and gas sources to provide information to assist in the development of comprehensive regulations to reduce methane emissions." On May 12, 2016, the EPA issued regulations (effective August 2, 2016) that build on the existing New Source Performance Standards, or the NSPS OOOO, promulgated by the EPA in 2012, as amended in 2013 and 2014. The regulations directly regulate methane and volatile organic compound, or VOC, emissions from various types of new and modified oil and gas sources. Some of those sources are already regulated under NSPS OOOO, while others, like hydraulically fractured oil wells, pneumatic pumps, and certain equipment and components at gas well sites and compressor stations, will be covered for the first time.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce GHG emissions and almost one-half of the states have already taken legal measures to reduce GHG emissions, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these GHG cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, natural gas liquids, and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

We may not be able to keep pace with technological developments in the industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we are in a position to do so. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies used now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, the business, financial condition, and results of operations could be materially adversely affected.

We may incur losses as a result of title deficiencies.

We own working and revenue interests in oil and natural gas leasehold interests. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available, and, in many instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers, in-house landmen or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We do not always perform curative work to correct deficiencies in the marketability of the title to us. In cases involving serious title problems, the amount paid for affected oil and natural gas leases can be lost, and the target area can become undrillable. We may be subject to litigation from time to time as a result of title issues.

The oil and natural gas business involves many operating risks that can cause substantial losses.

The oil and natural gas business involves a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;

- uncontrollable flows of underground natural gas, oil or formation water;
- natural disasters;
- pipe and cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormal pressure formations; and
- environmental hazards such as natural gas leaks, oil spills, pipeline ruptures or discharges of toxic gases.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources or equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; or
- repairs necessary to resume operations.

If we were to experience any of these problems, it could affect well bores, gathering systems and processing facilities, any one of which could adversely affect our ability to conduct operations. We may be affected by any of these events more than larger companies, since we have limited working capital. We currently have general liability insurance with a combined single limit per occurrence of not less than $1.0 million for bodily injury and property damage and a combined occurrence limit of $2.0 million, an excess umbrella liability policy for up to $5.0 million, and control of well insurance with limits of $5.0 million for any one occurrence. For other risks, however, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect operations and/or our financial condition. Moreover, we may not be able to maintain adequate insurance in the future at rates considered reasonable.

Risks Related to Our Common Stock

The price of our common stock may be volatile or may decline and you may have difficulty reselling any shares of our common stock.

Our common stock currently trades on the OTCQB Marketplace with very limited daily trading volume. The market price of our common stock may fluctuate significantly in response to numerous factors, many of which are beyond our control, including:

- the limited trading market in our common stock;
- commodity prices in general, and the price of oil in particular;
- regulatory developments, including new permitting regulations in Colorado;
- the success of our development efforts;
- our ability to successfully implement our business plan;
- failure to meet our revenue or profit goals or operating budget;

- decline in demand for our common stock;
- sales of additional amounts of common stock;

- downward revisions in securities analysts' estimates or changes in general market conditions;
- investor perception of our industry or our prospects; and
- general economic trends.

In addition, stock markets have experienced extreme price and volume fluctuations and the market prices of securities have been highly volatile. These fluctuations are often unrelated to operating performance and may adversely affect the market price of our common stock. As a result, investors may be unable to resell their shares at a fair price.

The sale of a substantial number of shares of our common stock may cause the price of our common stock to decline.

Substantially all of our outstanding common stock is currently available for resale under applicable securities laws. In addition, we have a significant amount of common stock that can be issued under outstanding warrant, options or convertible debt, and we are obligated to register that common stock for resale. Our common stock is currently thinly-traded and it is likely that market sales of large amounts of common stock (or the potential for those sales even if they do not actually occur) could cause the market price of our common stock to decline, which may make it difficult to sell our common stock in the future at a time and price which we deem reasonable or appropriate and may also cause investors to lose all or a part of their investment.

A small number of existing shareholders own a significant amount of our common stock, which could limit your ability to influence the outcome of any shareholder vote.

Our executive officers, directors, and certain beneficial owners would own approximately 70% of our common stock if the debtholders exercised certain conversion rights outstanding as of the date of this report. Under our Articles of Incorporation and Colorado law, the vote of a majority of the shares outstanding is required to approve certain shareholder action, such as the approval of a merger or share exchange. As a result, these individuals, if some convertible debt is converted, would control the outcome of shareholder votes on these matters for the foreseeable future, including votes concerning the election of directors, amendments to our Articles of Incorporation or proposed mergers or other significant corporate transactions. We have no existing agreements or plans for mergers or other corporate transactions that would require a shareholder vote at this time. However, shareholders should be aware that they may have limited ability to influence the outcome of any vote in the future.

Since our common stock is not presently nor expected to be listed on a national securities exchange, trading in our shares will likely be subject to rules governing "penny stocks," which will impair trading activity in our shares.

Our common stock is currently subject to rules adopted by the SEC regulating broker-dealer practices in connection with transactions in penny stocks. Those disclosure rules applicable to penny stocks require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized disclosure document required by the SEC. These rules also require a cooling off period before the transaction can be finalized.

In addition, FINRA rules require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low-priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer's financial status, tax status, investment objectives and other information. Under interpretations of these rules, FINRA believes that there is a high probability that speculative low-priced securities will not be suitable for at least some customers. FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit the ability to buy and sell our stock and have an adverse effect on the market value for our shares. Many brokers may be unwilling to engage in transactions in our common stock because of the added disclosure requirements and applicable FINRA requirements, thereby making it more difficult for stockholders to dispose of their shares.

If we are unable to implement and maintain effective internal control over financial reporting in the future, investors may lose confidence in the accuracy and completeness of our financial reports and the market price of our common stock may decline.

As a public company, we are required to maintain internal control over financial reporting and to report any material weaknesses in such internal control. Further, we are required to report any changes in internal controls on a quarterly basis. In addition, we are required to furnish a report by management on the effectiveness of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. If we identify material weaknesses in our internal control over financial reporting or are unable to assert that our internal control over financial reporting is effective, investors may lose confidence in the accuracy and completeness of our financial reports and the market price of the common stock could be negatively affected. A weakness in internal control could also result in a restatement of our consolidated financial statements, which could have a material adverse effect on the trading price of our stock.

Issuance of our stock in the future could dilute existing shareholders and adversely affect the market price of our common stock.

We have the authority to issue up to 210,000,000 shares of stock, including 200,000,000 shares of common stock and 10,000,000 shares of preferred stock, and to issue options and warrants to purchase shares of our common stock. We are authorized to issue significant amounts of common stock in the future, subject only to the discretion of our Board. These future issuances could be at values substantially below the price paid for our common stock by investors. In addition, we could issue large blocks of our stock to fend off unwanted tender offers or hostile takeovers without further shareholder approval. Because the trading volume of our common stock is relatively low, the issuance of our stock may have a disproportionately large impact on its price compared to larger companies.

The issuance of preferred stock in the future could adversely affect the rights of the holders of our common stock.

An issuance of preferred stock could result in a class of outstanding securities that would have preferences with respect to voting rights and dividends and in liquidation over the common stock and could, upon conversion or otherwise, have all of the rights of our common stock. Our Board of Directors' authority to issue preferred stock could discourage potential takeover attempts or could delay or prevent a change in control through merger, tender offer, proxy contest or otherwise by making these attempts more difficult or costly to achieve.

We have never paid dividends on our common stock and we do not anticipate paying any in the foreseeable future.

We have not paid dividends on our common stock to date, and it is unlikely that we will pay dividends for the foreseeable future. The provisions of the Secured Credit Facility prohibit the payment of dividends without the approval of the Secured Lenders, and it is unlikely that the Lenders would approve any dividends so long as the debt is outstanding. Our ability to pay dividends will also depend on our ability to successfully develop our business plan and generate additional revenue from operations. Further, our initial earnings, if any, will likely be retained to finance our operations. Any future dividends will depend upon our earnings, our then-existing financial requirements and other factors.

CAUTIONARY NOTE REGARDING FORWARD LOOKING STATEMENTS

In this report, references to "PetroShare," the "Company," "we," "us," and "our" refer to PetroShare Corp., the Registrant. The words "anticipates," "believes," "estimates," "expects," "intends," "may," "plans," "will," "would," and similar words or expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Forward-looking statements and information are necessarily based upon a number of estimates and assumptions that, while considered reasonable by management, are inherently subject to significant business, economic and competitive uncertainties, risks and contingencies, and there can be no assurance that such statements and information will prove to be accurate. Therefore, actual results and future events could differ materially from those anticipated in such statements and information. We caution you not to put undue reliance on these statements, which speak only as of the date of this report. Further, the information contained in this document or is a statement of our present intention and is based on present facts and assumptions, and may change at any time and without notice, based on changes in such facts or assumptions. Readers should not place undue reliance on forward-looking statements.

The important factors that could affect the accuracy of forward-looking statements and prevent us from achieving our stated goals and objectives include, but are not limited to information set forth under "Risk Factors" and the following:

- changes in the general economy affecting the disposable income of the public;
- changes in environmental law, including federal, state and local legislation;
- changes in drilling requirements imposed by state or local laws or regulations;
- terrorist activities within and outside the United States;
- technological changes in the crude oil and natural gas industry;
- acts and omissions of third parties over which we have no control;
- inflation and the costs of goods or services used in our operation;
- access and availability of materials, equipment, supplies, labor and supervision, power, and water;
- interpretation of drill hole results and the uncertainty of reserve estimates;

- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;

- the level of demand for the production of crude oil and natural gas;

- changes in our business strategy;

- potential failure to achieve production from development drilling projects; and
- capital expenditures.

Those factors discussed above and elsewhere in this report are difficult to predict and expressly qualify all oral and written forward-looking statements attributable to us or persons acting on our behalf. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not have any intention or obligation to update forward-looking statements included in this report after the date of this report, except as required by law. The preceding outlines some of the risks and uncertainties that may affect our forward-looking statements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may become involved in litigation relating to claims arising out of our operations in the normal course of business. No legal proceedings, government actions, administrative actions, investigations, or claims are currently pending against us or our officers and directors in which we are adverse.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Since November 23, 2015, our common stock has been quoted on the OTCQB of OTCLink under the symbol "PRHR." Prior to that date, there was no trading market for our common stock.

On April 2, 2019, the high and low sales price of our common stock on the OTCQB were \$0.38 and \$0.36, respectively.

Because our common stock is thinly traded and is not listed on a national securities exchange, the price for our common stock may be highly volatile and may bear no relationship to our actual financial condition or results of operations. Factors that we discuss in this report, including the many risks associated with our stock, may have a significant impact on the market price of our common stock. The market for our common stock will be affected by the offer and sale of our common stock by existing securities holders.

Holders of our Common Stock

As of April 2, 2019, we have outstanding 28,077,337 shares of common stock and approximately 162 holders of record of our common stock.

Transfer Agent

We have appointed Corporate Stock Transfer, Inc. of Denver, Colorado to be our transfer agent. Its address is 3200 Cherry Creek Drive South, #430, Denver, Colorado 80209 and its telephone number is 303-282-4800.

Penny Stock Rules

Due to the price of our common stock, as well as the fact that our stock is not listed on a national securities exchange, our stock is characterized as a "penny stock" under applicable securities regulations. As a result, we are subject to rules adopted by the SEC and FINRA regulating broker-dealer practices in connection with transactions in penny stocks. The broker or dealer proposing to effect a transaction in a penny stock must furnish the customer with a document containing information prescribed by rule and obtain from the customer an executed acknowledgment of receipt of that document. Also, because of the relatively low trading price of our common stock, many brokerage firms may be unwilling to effect transaction in our common stock.

The broker or dealer must also provide the customer with pricing information regarding the security prior to the transaction and with the written confirmation of the transaction. The broker or dealer must also disclose the aggregate amount of any compensation received or receivable by him in connection with such transaction prior to consummating the transaction and with the written confirmation of the trade. The broker or dealer must also send an account statement to each customer for which he has executed a transaction in a penny stock each month in which such security is held for the customer's account. The existence of these rules may have an adverse effect on the price of our stock, and the willingness of certain brokers to effect transactions in our stock.

Dividend Policy

We have never declared or paid dividends on our common stock and we do not expect to pay any in the near future. Payment of future dividends, if any, will be at the discretion of our Board of Directors after taking into account various factors, including the terms of any credit arrangements, our financial condition, operating results, current and anticipated cash needs and plans for expansion. Any earnings in the foreseeable future likely will be reinvested into our company. At the present time, the Secured Credit Facility limits our ability to pay dividends.

ITEM 6. SELECTED FINANCIAL DATA

Not required for smaller reporting companies.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

The following discussion summarizes our plan of operation as of April 2, 2019 for the next twelve months and the related anticipated capital expenditures. It also analyzes (i) our financial condition at December 31, 2018 and compares it to December 31, 2017, and (ii) our results of operations for the years ended December 31, 2018 and 2017. The following discussion and analysis should be read in conjunction with the accompanying consolidated financial statements and related notes and with the understanding that the actual future results may be materially different from what we currently expect.

As an oil and natural gas exploration and production company, our revenue, results of operation, cash flow from operations, reserve values, access to capital and future rate of growth are influenced by the prevailing prices of oil and natural gas. Changes in prices can affect, both positively and negatively, our financial condition, liquidity, ability to obtain financing, operating results, and the amount of oil and natural gas that we choose to produce. Prevailing prices for such commodities fluctuate in response to changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. The price received for oil and natural gas production is unpredictable, and such volatility is expected. All of our production is sold at market prices and, therefore, the amount of revenue that we realize, as well as our estimates of future revenues, is to a large extent determined by factors beyond our control.

Under the terms of the participation agreements covering our prospects and operating agreements with other third-party operators, we are required to pay our proportionate share of the costs of any wells in which we participate. In exchange, we are entitled to a proportionate share of the revenue, net of related expenses. Accordingly, the ultimate success of our business plan depends on our ability to generate sufficient cash flow from the sale of produced crude oil and natural gas from our interest in the leases to pay our overhead, outstanding liabilities and costs of future acquisitions and development.

We cannot fully determine what impact the volatility in crude oil and natural gas prices may have on our ongoing operations and future operations if such volatility continues into the future. Our decision on whether to drill and complete wells is based on both the prevailing commodity prices and the cost to drill such wells. Our ability to acquire financing and/or properties, drill wells, identify working interest and/or industry partners may all be negatively impacted by downward fluctuations in the price of oil and gas.

Going Concern

As described in the notes to our consolidated financial statements and the report of the independent registered public accounting firm accompanying those consolidated financial statements, there is substantial doubt about our ability to continue as a going concern. The uncertainty is based on our substantial current liabilities, negative working capital, accumulated deficit and limited cash flow, among other things, which existed as of December 31, 2018. We are dependent on improving cash flow and obtaining funding from the sale of debt or equity to continue as a going concern.

At December 31, 2018 we had a cash balance of approximately $2.6 million and other current assets of approximately $29.6 million including assets held for sale of $16.1 million, resulting in negative working capital of $32.9 million. We had net losses, including non-cash charges, of $17.3 million and $10.8 million for the years ended December 31, 2018 and 2017, respectively. At December 31, 2018 we were obligated to repay $9.4 million in principal plus accrued interest on our outstanding convertible promissory notes, which payment we did not make. The convertible notes are currently in default. We are in default under the terms of our Senior Secured Credit Facility and as a result $29.9 million including the outstanding principal and accrued interest and penalties are due. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. Some of our accounts payable obligations to vendors are past the due date and some of those vendors have filed liens or indicated an intent to liens against certain of our assets. The net proceeds from the sale of our non-operated assets in February 2019 have been applied by our Secured Lenders to amounts allegedly outstanding under the Secured Credit Facility. We will need to generate additional cash flow from operations and sell equity or debt to fund further drilling and acquisition activity and pay our existing obligations. If sufficient cash flow and additional financing is not available, we may be compelled to reduce the scope of our business activities and/or sell a portion of our interests in our oil and gas properties. This, in turn, may have an adverse effect on our ability to realize the value of our assets. These factors raise substantial doubt about our ability to continue as a going concern.

Plan of Operation and Expected Capital Expenditures

Our plan of operation for the next twelve months is to drill and complete 8 wells on our Brighton lakes pad. However, our ability to achieve this objective is subject to receipt of additional capital. If we are successful in raising additional capital by means of an equity financing in 2019, we may pursue another operated drilling program. Our goal is to increase the value of our company by selective deployment of capital in what we believe to be an attractive area in a premier oil and gas field.

Subject to the availability of additional capital and final permitting, we expect to spend $13.5 million to drill and complete 8 wells on our Brighton Lakes pad. We expect to begin drilling in the Spring of 2019 and expect that these wells are fully producing by December 2019, adding significantly to our revenue. We also intend to monitor the production from our operated Shook pad and vertical wells in order to determine whether production rates could be improved through work overs or by other means.

Results of Operations for the Year Ended December 31, 2018 Compared to December 31, 2017

The following provides selected operating results and averages for the years ended December 31, 2018 and 2017:

	For the year ended December 31,	
	2018	**2017**
Revenue		
Crude Oil	$ 16,809,145	$ 8,719,793
Natural Gas	2,456,927	1,525,833
NGLs	1,137,896	861,948
Total revenue	$ 20,403,968	$ 11,107,574
Total operating expense (1)	$ 4,147,762	$ 1,715,616
Depletion, depreciation and amortization expense	$ 7,067,729	$ 2,836,891
Interest expense	$ 13,074,289	$ 9,293,782
General and administrative expense	$ 4,155,651	$ 6,205,412
Net (loss)	$(17,307,747)	$(10,847,379)
Sales volume (2)(3)		
Crude Oil (Bbls)	287,984	188,529
Natural Gas (Mcfs)	773,396	549,846
NGLs (Bbls)	55,811	50,111
BOE	472,694	330,281
Average sales price		
Crude Oil (per Bbl)	$ 58.37	$ 46.25
Natural Gas (per Mcf)	$ 3.18	$ 2.78
NGLs (per Bbl)	$ 20.39	$ 17.20
BOE	$ 43.17	$ 33.63
Average per BOE		
Production cost	$ 5.65	$ 2.95
Total operating expense (1)	$ 8.77	$ 5.19
Depletion, depreciation and amortization expense	$ 14.95	$ 8.59

(1) Total operating expense (oil and gas production costs, including production taxes).
(2) Estimates are inherent in reported volumes to coincide with revenue accruals as a result of the timing of sales information reporting by third-party operators.
(3) Sales volumes are based upon crude oil, natural gas and NGL's sold or accrued during the period and differ from crude oil, natural gas and NGL's produced during the period.
(4) Averages calculated based upon non-rounded figures.

Overview: Fiscal 2018 was our second year of meaningful revenue, as we realized revenue from the non-operated horizontal wells in which we participated and revenue from our first operated horizontal wells. The 14 mid-length lateral wells on the Shook Pad commenced commercial production during the third quarter of 2018. However, for the year, we realized a net loss of $17.3 million, including non-cash charges, or $0.62 per share, compared to a net loss of $10.8 million, or $0.46 per share, for the year ended December 31, 2017. Production from the Shook Pad wells was periodically interrupted due to problems with the gathering pipeline into which we deliver our oil, adversely affecting our revenue for the year. In addition to the interruption in production, the increase in net loss of $6.5 million for the year ended December 31, 2018 resulted primarily from a significant increase in impairment charges, interest expense, depletion, depreciation and amortization and other non-cash expenses including amortization of debt discount associated with our Secured Credit Facility. We expect to continue operating at a loss until cash flow from the wells in which we have an interest is sufficient to cover operating costs, interest expenses, general and administrative and other expenses.

Revenue: Crude oil, natural gas and NGL sales revenue increased $9.3 million for the year ended December 31, 2018, to $20.4 million, from $11.1 million for the year ended December 31, 2017, attributable to increased production volume and higher oil and natural gas commodity prices. Crude oil, natural gas and NGL sales volumes increased by 142,413 BOE for the year ended December 31, 2018 compared to the year ended December 31, 2017. The increase, in turn, was primarily the result of production from the completion of 14 operated wells during 2018 in which we have an average net revenue interest of 39%, coupled with the completion of 14 non-operated wells. Our production in 2017 was solely from crude oil, natural gas and NGLs produced from vertical wells that we acquired during 2016 and the completion of 7 non-operated wells that were put on production in the in late 2016 and in 2017.

For the year ended December 31, 2018, our average sales price for oil was $58.37 per Bbl compared to $46.25 per Bbl for the year ended December 31, 2017, due to higher average oil spot prices during 2018. Overall, the increase in the average price per BOE of $9.53, or 28.3%, results primarily from increased sales volumes coupled with blended higher sales prices during the year ended December 31, 2018.

Operating Expense: Operating expense is comprised of the following items:

	Year ended December 31,	
	2018	**2017**
Lease operating costs	$ 1,415,453	$ 722,799
Production taxes	1,475,866	742,787
Transportation and other costs	1,256,443	250,030
Total	$ 4,147,762	$ 1,715,616

Total operating expense increased in 2018 commensurate with increased production. This reflects our operated and additional non-operated properties coming online in 2018, while 2017 primarily reflects the operations of legacy vertical wells and a smaller number of non-operated wells.

Lease operating costs, or LOE, per BOE was $2.99 for the year ended December 31, 2018, compared to $2.19 for the year ended December 31, 2017. As a percent of crude oil, natural gas and NGL sales revenue, routine LOE was 6.94% for the year ended December 31, 2018, compared to 6.51% for the year ended December 31, 2017. Production taxes for the year ended December 31, 2018 amounted to $1.5 million as compared to $0.7 million for the year ended December 31, 2017.

Overall operating costs (crude oil, natural gas and NGL operating costs excluding production taxes) per BOE was $5.65 for the year ended December 31, 2018, compared to $2.95 for the year ended December 31, 2017.

Depletion, depreciation and amortization expense: Depletion, depreciation and amortization increased by $4.3 million in 2018, from $2.8 million for the year ended December 31, 2017 to $7.1 million for the year ended December 31, 2018. The increase was the result of increased production volumes related to wells coming online during the 2018 period, partially offset by an increase in our reserves.

***Impairment expense**:* During 2018, we recognized an impairment expense of $9.9 million related to the sale of our non-operated assets on February 27, 2019. This impairment resulted from the sale of our non-operated assets in February 2019 and our determination that the net unamortized costs of the assets exceeded the proceeds from the sale. We incurred no comparable expense during 2017.

Interest expense: During 2018, we recognized interest expense of $13.1 million compared to $9.3 million for the year ended December 31, 2017. The interest expense recognized 2018 relates to the interest on our Secured Credit Facility, our unsecured convertible notes, the amortization of debt discounts and accrued default interest and penalties related to our technical defaults under the Secured Credit Facility. During the year ended December 31, 2017, interest expense primarily related to advances on our two lines of credit and our convertibles notes payable.

The following table presents the components of interest expense for the years ended December 31:

	2018	2017
Interest incurred at the contract rate	$ 5,434,231	$ 2,004,041
Default interest	312,500	—
Make whole premium	3,357,875	—
Accretion of debt discount	6,126,680	7,546,497
Interest capitalized	(2,156,997)	(259,756)
Total	$ 13,074,289	$ 9,293,782

Change in fair value – derivative liability: During 2018 we recognized other income of $1.4 million related to a change in the fair value of the compound derivative liabilities embedded in the Secured Credit Facility. Accounting standards require us to re-measure the value of the derivative liabilities each reporting period, and any changes in fair value are included in Other income or Other expense. During 2017, we did not have any derivative liabilities.

General and administrative expenses: We incurred general and administrative expenses of $4.2 million during the year ended December 31, 2018, a decrease of $2.0 million from 2017, or 33%. This decrease is primarily attributable to decreased non-cash compensation of $0.6 million, decreases in professional fees of $0.6 million, increases in drilling overhead charges recorded as a reduction to general and administrative expense of $1.1 million and increases in producing overhead charges of $0.6 million recorded as a reduction to general and administrative expense, offset by increased salaries and insurance expense of $0.9 million. In 2017, we incurred general and administrative expenses of $6.2 million.

LIQUIDITY AND CAPITAL RESOURCES

Overview

In 2018, our shortage of capital and liquidity was exacerbated. Historically, we have relied on sales of our equity securities, borrowing and advances from our working interest partners to fund operations. In 2018, our need for additional capital became more acute, as we accelerated the pace of development of our properties, including completing our first operated drilling program. However, the state of the equity markets for junior exploration and production companies in 2018 forced us to rely on other avenues for funding during the year.

2018 Financing

In February 2018, we completed the Secured Credit Facility. Under the Secured Credit Facility, we refinanced $5 million in December 2017 and received gross proceeds of an additional $20 million in February 2018. The Secured Credit Facility proceeds were utilized to repay amounts due to affiliates of the Secured Lenders under pre-existing lines of credit, for fees associated with the Secured Credit Facility and for development costs incurred in connection with the completion of our operated Shook pad.

Working Capital

As of December 31, 2018, we had negative working capital of $32.9 million, comprised of current assets of $32.2 million and current liabilities of $65.1 million. A significant portion of the current assets consisted of property held for sale, which property was disposed of subsequent to year end and the proceeds of which were applied by the Secured Lenders against the amounts owed to them. Working capital decreased by $15.1 million from December 31, 2017, primarily due to the default and subsequent reclassification of amounts due under our Secured Credit facility from a long-term liability to a current liability.Current liabilities increased by approximately $38 million at December 31, 2018 compared to 2017.

Cash Flows

Year Ended December 31, 2018 Compared to December 31, 2017

<u>Operating Activities</u>

Net cash provided by operating activities during the year ended December 31, 2018 was $4.6 million, compared to $10.4 million during the year ended December 31, 2017, representing a decrease of $5.7 million. The increased net loss in 2018 accounted for most of the difference.

<u>Investing Activities</u>

Cash used in investing activities in 2018 decreased to $13.9 million from $20.3 million in the 2017 period. During the 2018 period, our drilling and other development activity, as well as acquisitions of property, decreased due to our lack of working capital. During 2017, we spent $17.1 million on drilling and other development activities on our properties and $3.2 million on acquisitions of oil and gas properties.

<u>Financing Activities</u>

During 2018, we closed on the Secured Credit Facility which provided net cash proceeds of $11.2 million and provided resources after repaying $6.5 million in principal and $1.1 million in accrued interest from other financings. The total face value of the Secured Credit Facility is $25.0 million, including the $5.0 million that originated in 2017.

Off-Balance Sheet Arrangements

We have no material off-balance sheet transactions, arrangements, or obligations.

Critical Accounting Policies

Use of Estimates in the Preparation of Consolidated Financial Statements

The discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States (“US GAAP”). The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 2 of the Notes to Consolidated Financial Statements included as part of this Form 10-K. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas reserve estimates, on a periodic basis and base our estimates on historical experience, independent third-party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Assets Held for Sale

We occasionally identify specific oil and gas properties that we wish to sell. At the end of each reporting period, we evaluate properties that might be sold to determine whether any should be reclassified as held for sale. The held-for-sale criteria include: a commitment to a plan to sell; the asset is available for immediate sale; an active program to locate a buyer exists; the sale of the asset is probable and expected to be completed within one year; the asset is being actively marketed for sale; and it is unlikely that significant changes to the plan will be made. If each of these criteria is met, the property is reclassified as held for sale on our consolidated balance sheets. We also determine whether the fair values of the properties held for sale are less than the net unamortized cost. If an impairment is indicated, the assets held for sale are recorded at fair value less costs to sell and an impairment expense is recorded.

Successful Efforts Method of Accounting

Our application of the successful efforts method of accounting for our oil and gas exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination whether commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Oil and Gas Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Our independent petroleum engineers, Cawley Gillespie, prepare a reserve and economic evaluation of all of our properties on a well-by-well basis. The accuracy of reserve estimates is a function of the:

- quality and quantity of available data;
- interpretation of that data;
- accuracy of various mandated economic assumptions; and
- judgment of the independent reserve engineer.

One of the most significant estimates we make is the estimate of oil, natural gas and NGL reserves. Oil, natural gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given area may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs and these estimates are inherently uncertain. For example, if estimates of proved reserves decline, our depletion, depreciation and amortization (DD&A) rate will increase, resulting in an increase in net loss. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of oil and gas properties exceeds fair value and could result in an impairment charge, which would increase our loss. We cannot predict what reserve revisions may be required in future periods.

The recent volatility in oil, natural gas and NGL prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. We are unable to predict future commodity prices with any greater precision than the futures market. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs.

Depletion, Depreciation, Amortization

Our DD&A rate is dependent upon our estimates of total proved producing and proved developed reserves, which incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn increases our net loss. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Proved Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to the estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production, future capital expenditures, future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of proved crude oil and natural gas properties in the consolidated statements of operations.

Our impairment analyses require us to apply judgment in identifying impairment indicators and estimating future cash flows of our oil and gas properties. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

Impairment of Unproved Oil and Gas Properties

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. We evaluate significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration and abandonment costs in the consolidated statements of operations.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") consist of estimated future costs associated with the plugging and abandonment of oil, natural gas and NGL wells, removal of equipment and facilities from leased acreage, land restoration in accordance with applicable local, state and federal laws, and applicable lease terms. The fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of proved crude oil and natural gas properties. The recognition of an ARO requires management to make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate to be used; and inflation rates. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact operating results as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Stock-Based Compensation

We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. The determination of the fair value of stock-based awards at the grant date requires judgment in developing assumptions, which involve a number of variables. These variables include, but are not limited to, the expected stock price volatility over the term of the awards, the expected dividend yield and the expected stock option exercise behavior.

Our computation of expected volatility is based on a combination of historical and market-based implied volatility. The volatility rate was derived by examining historical stock price behavior and assessing management's expectations of stock price behavior during the term of the option. The term of the options was derived based on the "simplified method" calculation. The simplified method allows companies that do not have sufficient historical experience to provide a reasonable basis for an estimate to instead estimate the expected term of a "plain vanilla" option by averaging the time to vesting and the full term of the option. ("Plain vanilla" options are options with the following characteristics: (1) the options are granted at-the-money; (2) exercisability is conditional only upon performing service through the vesting date; (3) if an employee terminates service prior to vesting, the employee would forfeit the options; (4) if an employee terminates service after vesting, the employee would have a limited time to exercise the options (typically 30 to 90 days); and (5) the options are nontransferable and non-hedgeable.) The Company periodically evaluates the applicability of using the simplified method with respect to the characteristics noted above to estimate the expected term of our options and will continue to do so as our business continues to evolve. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

Going Concern Assessment

Pursuant to Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") No. 2014-15*, Presentation of Financial Statements – Going Concern,* we have assessed our ability to continue as a going concern for a period of one year from the date of the issuance of these consolidated financial statements. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year from the consolidated financial statement issuance date.

Management has evaluated these conditions and determined that increased revenues from the Company's operated properties may allow the Company to meet its ongoing operational obligations. There is uncertainty whether management's plans, if executed, will allow us to meet all of our obligations.

Recent Accounting Pronouncements

Please refer to Recent Accounting Pronouncements in *Note 2—Basis of Presentation and Significant Accounting Policies* in Part II, Item 8 of this report.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and within this prospectus:

"***Bbl***"—Barrel or 42 US gallons liquid volume.

"***MBbls***"—One thousand Bbls.

"***BOE***"—One barrel of crude oil equivalent, which combines Bbls of oil, Bbls of natural gas liquids, and Mcf of natural gas by converting each six Mcf of natural gas to one Bbl of oil.

"***MBOE***"—One thousand BOE.

"***BOE/D***"—Barrels of oil equivalent per day.

"***Condensate***"—A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"***Developed acreage***"—The number of acres that are allocated or assignable to producing wells or wells capable of production.

"***Development well***"—A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved crude oil or natural gas reserves.

"***Exploratory well***"—A well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil or natural gas in another reservoir, or to extend a known reservoir.

"***Field***"—An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

"***Gross acres***"—The number of acres in which the Company owns a gross working interest.

"***Gross well***"—A well in which the Company owns a working interest.

"***Leases***"—Full or partial rights in mineral interests authorizing the leaseholder to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"***Mcf***"—One thousand cubic feet of natural gas.

"***MMcf***"—One thousand Mcf.

"***MMBtu***"—One million British thermal units—a measure of the amount of energy required to raise the temperature of a one-pound mass of water one-degree Fahrenheit at sea level.

"***Net acres***" or "***Net wells***"—The sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"***NGL***"—Means natural gas liquids.

"***Operator***"—The individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"***Producing well***"—A well that is currently producing crude oil, natural gas, or liquids.

"***Productive well***"—A producing well or a well mechanically capable of production.

"***Prospect***"—A location where hydrocarbons such as crude oil and natural gas are believed to be present in quantities which are economically feasible to produce.

"***Proved developed reserves***"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

“***Proved reserves***”—Proved crude oil and natural gas reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

“***Proved undeveloped reserves***”—Proved crude oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

“***Reservoir***”—A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“***Resources***”—Quantities of crude oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

“***Revenue interest***”—The amount or percentage of revenue/proceeds derived from a producing well that the owner is entitled to receive.

“***Section***”—640 acres.

“***Shut-in***”—A well which is capable of producing but is not presently producing.

“***Spacing***” or “***Spacing Unit***”—The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

“***Standardized measure***”—The present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs and future income tax expenses, using prices and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depletion, depreciation and amortization and discounted using an annual discount rate of 10% to reflect timing of future cash flows.

“***Undeveloped acreage***”—Leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil and natural gas, regardless of whether or not such acreage contains proved reserves. Undeveloped acreage includes net acres under the bit until a productive well is established in the spacing unit.

“***Unproved property***”—A property or part of a property with no proved reserves.

“***Working interest***”—The amount or percentage of costs that an owner is required to pay of drilling and production expenses. It also gives the owners, in the aggregate, the right to drill, produce and conduct operating activities on the property and to share in any revenue from the production.

“***Workover***”—Operations on a producing well to restore or increase production.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not required for smaller reporting companies.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

CPAs & BUSINESS ADVISORS

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors
PetroShare Corp.
Englewood, Colorado

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of PetroShare Corp. (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, changes in shareholders' equity (deficit), and cash flows, for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Going Concern

The accompanying consolidated financial statements have been prepared assuming that the entity will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the entity is in default under the terms of its secured credit facility, is in default under the terms of its convertible promissory notes, has suffered recurring losses from operations and has a net capital deficiency that raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. PetroShare Corp. is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose expressing an opinion on the effectiveness of the entity's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Eide Bailly LLP

We have served as the Company's auditor since 2017.

Denver, Colorado
April 3, 2019

PetroShare Corp.
Consolidated Balance Sheets
December 31,

	2018	2017
ASSETS		
Current assets:		
Cash	$ 2,636,943	$ 713,924
Accounts receivable - joint interest billing, net of allowance	495,911	828,583
Accounts receivable - joint interest billing - related party	1,158,213	204,730
Accounts receivable - crude oil, natural gas and NGL sales	11,659,479	1,412,612
Prepaid expenses and other assets	178,259	26,795
Deferred financing fee, net	—	251,389
Assets held for sale, net of costs to sell	16,090,898	—
Total current assets	32,219,703	3,438,033
Crude oil and natural gas properties - using successful efforts method:		
Proved crude oil and natural gas properties	41,017,944	22,144,366
Unproved crude oil and natural gas properties	2,055,752	1,919,335
Wells in progress	1,194,114	9,858,262
Less: accumulated depletion, depreciation and amortization	(14,395,458)	(2,849,374)
Crude oil and natural gas properties, net	29,872,352	31,072,589
Property, plant and equipment, net	115,350	168,411
Other assets	357,070	233,871
TOTAL ASSETS	**$ 62,564,475**	**$ 34,912,904**
LIABILITIES & SHAREHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable and accrued liabilities	$ 24,385,417	$ 4,140,352
Accounts payable and accrued liabilities - related party	7,624,877	589,496
Oil and gas revenue distributions payable	2,501,095	148,103
Drilling advances - related party	—	680,248
Asset retirement obligation	843,796	288,784
Line of credit - related party	—	5,000,000
Supplemental line of credit	—	3,552,500
Derivative liabilities – Secured Credit Facility	241,800	—
Convertible notes payable, net	9,358,100	6,831,897
Secured Credit Facility, net	20,182,264	—
Total current liabilities	65,137,349	21,231,380
Long-term liabilities		
Credit facility, net	—	4,896,565
Other long-term liabilities	448,465	67,265
Asset retirement obligation	1,246,151	834,660
Total liabilities	66,831,965	27,029,870
Shareholders' equity (deficit):		
Preferred stock, $0.01 par value, 10,000,000 shares authorized, none issued or outstanding	—	—
Common stock, $0.001 par value, 100,000,000 shares authorized, 28,089,765 and 27,718,802 shares issued and outstanding, respectively with 184,350 and 155,350 shares subject to vesting restrictions respectively	28,090	27,719
Additional paid-in capital	33,710,588	28,553,736
Accumulated deficit	(38,006,168)	(20,698,421)
Total Shareholders' Equity (Deficit)	(4,267,490)	7,833,034
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY (DEFICIT)	**$ 62,564,475**	**$ 34,912,904**

The accompanying notes are an integral part of these consolidated financial statements.

PetroShare Corp.
Consolidated Statements of Operations
For the years ended December 31,

	2018	2017
REVENUE:		
Crude oil sales	$ 16,809,145	$ 8,719,793
Natural gas sales	2,456,927	1,525,833
NGL sales	1,137,895	861,948
Total revenue	20,403,967	11,107,574
COSTS AND EXPENSES:		
Lease operating expense	1,415,453	722,799
Production taxes, gathering and marketing	2,732,309	992,817
Exploration and abandonment costs	580,881	61,693
Depletion, depreciation and amortization	7,067,729	2,836,891
Accretion expense	117,636	99,682
Asset retirement and plugging expense	(2,989)	9,608
Impairment of proved crude oil and natural gas properties	9,896,807	—
General and administrative expense	4,155,651	6,205,412
Total costs and expenses	25,963,477	10,928,902
Operating (loss) income	(5,559,510)	178,672
OTHER INCOME (EXPENSE):		
Other income (expense)	(102,165)	39,381
Change in fair value of derivative liabilities	1,428,217	—
Interest expense	(13,074,289)	(9,293,782)
Loss on conversion of notes payable	—	(1,771,650)
Total other (expense)	(11,748,237)	(11,026,051)
Net (loss)	**$(17,307,747)**	**$(10,847,379)**
Net (loss) per share:		
Basic and diluted	**$ (0.62)**	**$ (0.46)**
Weighted average number of shares outstanding:		
Basic and diluted	**27,991,742**	**23,530,583**

The accompanying notes are an integral part of these consolidated financial statements.

PetroShare Corp.
Consolidated Statements of Changes in Shareholders' Equity (Deficit)
For the years ended December 31, 2018 and 2017

	Common Stock		Additional Paid-In	Accumulated	
	Shares	Amount	Capital	(Deficit)	Total
Balance at December 31, 2016	21,964,282	$ 21,964	$ 11,405,225	$ (9,851,042)	$ 1,576,147
Issuance of common stock in connection with conversion of convertible notes payable	4,814,265	4,814	7,062,528	—	7,067,342
Issuance of common stock for lease acquisition	470,555	471	846,529	—	847,000
Issuance of common stock for loan extension	250,000	250	387,250	—	387,500
Issuance of restricted shares	219,700	220	155,111	—	155,331
Beneficial conversion feature on convertible notes payable	—	—	4,329,365	—	4,329,365
Warrants issued in connection with convertible notes payable	—	—	2,978,796	—	2,978,796
Stock-based compensation	—	—	1,388,932	—	1,388,932
Net (loss)	—	—	—	(10,847,379)	(10,847,379)
Balance at December 31, 2017	27,718,802	$ 27,719	$ 28,553,736	$ (20,698,421)	$ 7,883,034
Issuance of common stock in connection with conversion of convertible notes payable	135,963	136	203,811	—	203,947
Issuance of common shares as compensation	145,000	145	162,105	—	162,250
Issuance of restricted shares	90,000	90	101,018	—	101,108
Beneficial conversion feature on Secured Credit Facility	—	—	2,272,775	—	2,272,775
Warrants issued in connection with Secured Credit Facility	—	—	1,521,451	—	1,521,451
Stock-based compensation	—	—	895,692	—	895,692
Net (loss)	—	—	—	(17,307,747)	(17,307,747)
Balance at December 31, 2018	28,089,765	$ 28,090	$ 33,710,588	$ (38,006,168)	$ (4,267,490)

The accompanying notes are an integral part of these consolidated financial statements.

PetroShare Corp.
Consolidated Statements of Cash Flows
For the years ended December 31,

	2018	2017
Cash flows from operating activities:		
Net (loss)	$ (17,307,747)	$ (10,847,379)
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	7,067,729	2,836,891
Deferred rental liability	(23,625)	6,526
Accretion of asset retirement obligation	117,636	99,682
Accretion of debt discounts and deferred financing fee	6,380,057	7,666,313
Loss on conversion of notes payable	—	1,771,650
Stock-based compensation	1,159,051	1,544,261
Change in fair value – derivative liabilities	(1,428,217)	—
Default penalties incurred in connection with Secured Credit Facility	3,670,375	—
Impairment of proved crude oil and natural gas properties	9,896,807	—
Break-up fees in connection with abandonment of lease acquisition	580,881	—
Bad debt expense	131,395	—
Changes in operating assets and liabilities:		
Accounts receivable - joint interest billing	(66,470)	(588,132)
Accounts receivable - joint interest billing - related party	204,731	81,495
Accounts receivable - crude oil, natural gas and NGL sales	(10,246,868)	(1,233,376)
Prepaid expenses, other assets and liabilities	130,164	961,048
Settlement of asset retirement obligations	(174,532)	—
Accounts payable and accrued liabilities	758,525	7,053,693
Accounts payable and accrued liabilities- related party	2,123,621	589,496
Oil and gas revenue distributions payable	2,352,992	3,578
Drilling advances - related party	(680,248)	445,796
Net cash provided by operating activities	4,646,257	10,391,542
Cash flows from investing activities:		
Additions of property, plant and equipment	—	(91,186)
Development of crude oil and natural gas properties	(13,379,249)	(17,052,313)
Acquisitions of proved and unproved crude oil and natural gas properties	(507,181)	(3,202,380)
Net cash (used in) investing activities	(13,886,430)	(20,345,879)
Cash flows from financing activities:		
Repayment of supplemental line of credit	—	(3,552,500)
Borrowings on Secured Credit Facility	11,163,192	—
Convertible notes issued for cash	—	11,771,349
Net cash provided by financing activities	11,163,192	8,218,849
Cash:		
Net increase (decrease) in cash	1,923,019	(1,735,488)
Cash, beginning of period	713,924	2,499,412
Cash, end of period	$ 2,636,943	$ 713,924
Supplemental cash flow disclosure:		
Cash paid for interest, net of amounts capitalized of $2.2 million and $0.3 million as of December 31, 2018 and 2017	$ 3,394,575	$ 640,410
Non-cash investing and financing activities:		
Addition of oil and natural gas properties – Asset exchange agreement	$ 2,873,912	$ —
Accrued development costs of crude oil and natural gas properties	$ 16,015,992	$ 1,719,481
Revisions and other non-cash charges in asset retirement obligation	$ 1,023,400	$ 127,826
Conveyance of oil and gas properties – to satisfy supplemental line of credit	$ 2,052,500	$ 4,683
Addition of property, plant and equipment through tenant improvement allowance	$ —	$ 84,460
Embedded derivative liabilities – Secured Credit Facility	$ 1,670,017	$ —
Previous borrowings refinanced through Secured Credit Facility	$ 6,500,000	$ —
Issuance of common stock warrants in connection with Secured Credit Facility	$ 1,521,451	$ —

Issuance of common stock warrants in connection with convertible notes payable	$ —	$ 2,978,796
Beneficial conversion feature in connection with Secured Credit Facility and convertible notes payable	$ 2,272,775	$ 4,329,365
Issuance of common stock in connection with conversion of notes payable and accrued interest	$ 203,947	$ 5,295,692
Conversion of notes payable and accrued interest – Additional paid in capital	$ —	$ 7,067,342
Issuance of common stock in connection with lease acquisitions	$ —	$ 847,000
Issuance of common stock in connection with deferred financing fee	$ —	$ 387,500
Accounts payable and accrued interest repaid through Secured Credit Facility	$ 1,086,808	$ 4,895,128
Financing fee paid through Secured Credit facility	$ 1,250,000	$ 104,871

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1 – ORGANIZATION AND NATURE OF BUSINESS

PetroShare Corp. (“PetroShare” or the “Company”) is a corporation organized under the laws of the State of Colorado on September 4, 2012 to investigate, acquire and develop crude oil and natural gas properties in the Rocky Mountain or mid-continent portion of the United States. Since inception, the Company has focused on financing activities and the acquisition, exploration and development of crude oil and natural gas prospects in the Denver-Julesburg Basin, or DJ Basin, in northeast Colorado.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND BASIS OF PRESENTATION

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“US GAAP”). The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss.

Principles of Consolidation

The consolidated financial statements include the accounts and balances of the Company and its wholly-owned subsidiary, CFW Resources, LLC, a Colorado limited liability company. The Company’s undivided interests in joint operating ventures are proportionately consolidated.

Use of Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as the disclosure of contingent assets and liabilities. Estimated quantities of crude oil, natural gas and natural gas liquids are the most significant of the Company’s estimates. All reserve data used in the preparation of these consolidated financial statements are based on estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and natural gas liquids. There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil, natural gas and natural gas liquids that are ultimately recovered.

Other items subject to significant estimates and assumptions include, but are not limited to, the carrying amounts of crude oil and natural gas properties, accrued and unpaid revenues and unbilled costs, asset retirement obligations, deferred income tax liabilities and assets, including any associated valuation allowances, derivative liabilities, convertible notes payable and the Secured Credit Facility. Furthermore, valuation assumptions related to the Company's stock-based compensation and fair value financial instruments require significant judgments and estimates. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. Actual results could be significantly different from the estimates.

Income (or Loss) Per Common Share

Basic earnings (or loss) per share is computed by dividing net income (or loss) by the weighted average number of common shares outstanding during the period. Diluted earnings (or loss) per share is computed after considering the potential dilution from additional shares that would be issued pursuant to the conversion of debt, exercise of warrants, and fulfillment of outstanding equity awards. Any potentially dilutive securities that have an anti-dilutive impact on the per share calculation are excluded. During periods in which the Company reports a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the impact of all potentially dilutive securities would be anti-dilutive.

The following table presents the number of potentially dilutive securities that were excluded from the calculation at December 31, 2018 and 2017:

	December 31, 2018	December 31, 2017
Exercisable stock options	4,621,000	4,347,500
Warrants to purchase common stock	9,088,800	7,588,800
Shares underlying secured credit facility and convertible notes	23,489,786	6,372,066
Total	37,199,586	18,308,366

Cash, cash equivalents, and restricted cash

During the periods presented herein, the Company had no cash equivalents or restricted cash.

Revenue Recognition

Oil sales

Under the Company's oil sales contracts, the Company sells oil production at the point of delivery and collects an agreed upon index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the point of delivery at the net price received. Payment is generally received from the customer in the month following delivery.

Natural gas and natural gas liquids

Under the Company's natural gas sales processing contracts, the Company delivers commingled natural gas and natural gas liquids (NGLs) to a midstream processing entity. The midstream processing entity gathers and processes the various hydrocarbons and remits proceeds to the Company for the resulting sale. Under these processing agreements, the Company recognizes revenue when control transfers to the purchaser at the point of delivery. Payment is generally received from the customer one to two months following delivery. Revenue is recognized net of gathering and processing fees.

Disaggregation of Revenue. The following table presents revenues disaggregated by product:

Operating revenues	2018	2017
Crude oil sales	$ 16,809,145	$ 8,719,793
Natural gas sales	2,456,927	1,525,833
NGL sales	1,137,895	861,947

Total Operating Revenues	$ 20,403,967	$ 11,107,574

Accounts Receivable – Crude oil, natural gas and NGLs

Accounts receivable – Crude oil, natural gas and NGLs consists of amounts due from customers for the sale of hydrocarbons. In general, settlements for hydrocarbon sales occur 30 to 90 days after the month in which the oil, natural gas or other hydrocarbon products were produced.

Accounts Receivable – Joint interest billing

Accounts receivable – Joint interest billing represents costs to be reimbursed by the Company's working interest partners under joint operating agreements. Collateral is not required for such receivables, nor is interest charged on past due balances. However, should a working interest partner default on its obligation, the Company would have a claim against their future pro rata revenue and to any reserves attributable to the joint interest.

Allowance for doubtful accounts

The Company regularly reviews outstanding accounts receivable for indication that amounts may not be collectible. The Company's allowance for doubtful accounts is based on analysis of historical bad debt experience, current receivables aging, and expected future write-offs, as well as an assessment of specific identifiable customer accounts considered at risk or uncollectible. An allowance of $0.1 million and $nil was recorded as of December 31, 2018 and 2017, respectively.

Capitalized Interest Costs

The Company capitalizes interest costs as part of the historical cost of developing assets. Significant oil and gas investments in unproved properties and significant exploration and development projects including wells in progress that have not commenced production are assets that qualify for interest capitalization during the period that they are being prepared for their intended use. Capitalized interest is calculated by using the weighted average interest cost on the Company's outstanding debt, including the accretion of interest expense associated with debt discounts. The interest costs capitalized into oil and gas properties totaled $2.2 million and $0.3 million for the years ended December 31, 2018 and 2017, respectively.

Concentration of Credit Risk and Major Customers

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to regular review.

The Company does not believe the loss of any single purchaser of its production would materially impact its operating results, as crude oil, natural gas, and NGLs are products with well-established markets and numerous purchasers in the Company's operating region. The Company had the following major customers, which accounted for 10 percent or more of its total crude oil, natural gas, and NGL production revenue for at least one of the periods presented:

	For the Years Ended December 31,	
	2018	**2017**
Great Western Oil and Gas Company	40.5%	22%
Rose Rock Midstream Crude LP	33.4%	-
PDC Energy, Inc	20.6%	71%

The Company maintains its primary bank accounts with a large, multinational bank that has branch locations in the Company's areas of operations. Bank account balances periodically exceed federally insured limits. To mitigate risk of loss, the Company's policy is to maintain its deposits with high quality financial institutions.

Crude Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its crude oil and natural gas properties. Under this method of accounting, the costs incurred to acquire, drill, and complete productive wells, development wells, and proved properties are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Costs of drilling exploratory wells are initially capitalized as wells in progress until the viability of the well is determined. Successful exploratory wells are capitalized, and unsuccessful exploratory wells are charged to expense.

Proved

Proved properties include all capitalized costs associated with proved developed and proved undeveloped reserves. Depletion, depreciation and amortization ("DDA") of proved properties is calculated as a group of assets (properties aggregated based upon common attributes) using the units-of-production method. DDA of development costs, including capitalized tangible and intangible drilling costs, well equipment, and facilities costs, is based on the estimate of proved developed reserves. Similarly, DDA of proved leasehold costs, including proved undeveloped leases, is calculated using the same method based on the estimate of total proved reserves (both developed and undeveloped). Currently, the Company's properties are located solely within the Wattenberg Field of the DJ Basin, which is considered one field for unit-of-production calculations. The Company based its determination upon certain common attributes, including geological structure, geographic proximity, cost environment, and similar operating practices.

The Company periodically assesses its proved crude oil and natural gas properties for impairment. The impairment test compares the net capitalized costs of the properties to the estimated undiscounted future net cash flows. If the net capitalized costs exceed estimated future net cash flows, an impairment expense is recorded to reduce the carrying value of the property.

The sale or other disposition of part of a proved property is reported as a normal retirement, under which no gain or loss is recognized, unless doing so significantly affects the unit-of-production amortization rate. Gains or losses are recorded in the statement of operations for all other divestiture activities.

Unproved

Unproved properties consist of costs to acquire unproved and unevaluated leases and other mineral assets. All acquisition costs are initially capitalized. When successful wells are drilled on unproved properties, the associated costs are reclassified as proved properties and depleted on a units-of-production basis. The Company periodically evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or plans to develop acreage. Individually insignificant unproved properties are evaluated on a composite basis, and, when appropriate, are amortized as a group based on past success, experience and average lease-term lives.

Exploration costs

Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

Costs of drilling exploratory wells are initially capitalized, pending determination of whether the well contains proved reserves. If an exploratory well does not contain proved reserves, the costs of drilling the well and other associated costs are charged to expense. Costs incurred for exploratory wells that contain reserves, which cannot yet be classified as proved, continue to be capitalized if (a) the well has found a sufficient quantity of reserves to justify completion as a producing well, and (b) the Company is making satisfactory progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if the Company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well costs are expensed.

Property, Plant and Equipment

Property, plant and equipment are stated at cost, less accumulated depreciation. Depreciation is computed using straight-line method over the estimated useful lives of the related assets. Expenditures for renewals and betterments which increase the estimated useful life or capacity of the asset are capitalized; expenditures for repairs and maintenance are expensed as incurred.

Related Party Transactions

The Company engages in a number of transactions with Providence Energy Operators, LLC ("PEO") and its affiliates. PEO is a subsidiary of Providence Energy Corporation, a privately-held corporation based in Dallas, Texas. PEO is the beneficial owner of 11.6% of our outstanding common stock. We have a participation agreement that grants PEO the option to acquire up to a 50% interest and participate in any oil and gas development on acreage we obtain within an area of mutual interest (AMI) near our Southern Core area. To date, PEO has exercised its option under the participation agreement or otherwise participated or agreed to participate in all acreage acquisitions and drilling operations. As discussed elsewhere in this report, an affiliate of PEO is a major participant in our principal lender group through which we currently maintain a $25.0 million Secured Credit Facility. The Board of Directors is required to approve all significant related party transactions.

Drilling Advances - Related Party

The Company's drilling advances consist of cash provided to the Company from its joint interest partners for planned drilling activities. Advances are applied against the joint interest partners' share of costs incurred.

Income Taxes

The Company accounts for deferred income taxes under the asset and liability method whereby it recognizes deferred tax assets and liabilities based on the tax effects of temporary differences between the cost basis of assets and liabilities reported for financial reporting purposes compared to income tax reporting purposes using currently enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled. Deferred tax assets are also recognized for future tax consequences attributable to operating loss carryforwards. The Company provides a valuation allowance for deferred tax assets when it does not consider realization of such assets to be more likely than not. The Company complies with authoritative accounting guidance regarding uncertain tax provisions. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. The Company does not expect a significant change to the recorded unrecognized tax benefits in 2018.

Asset Retirement Obligation

The Company recognizes an estimated liability for future costs associated with the dismantlement, abandonment, or other restoration required when its oil and gas assets are retired or otherwise permanently removed from service. Calculation of an asset retirement obligation ("ARO") requires estimates about several future events, including the estimated date of retirement, the costs to remove the asset from service, and inflation factors. The ARO is initially estimated based upon discounted cash flows over the life of the asset and is accreted to full value over time using the Company's credit-adjusted risk-free interest rate.

Upon initial recognition of an ARO, the carrying amount of the associated asset is increased by the same amount. The capitalized costs are included in the periodic calculation of DD&A and are subject to impairment testing. If the estimated timing or estimated cash flow of the ARO changes, an adjustment is recorded to both the ARO and the asset retirement cost.

Assets Held for Sale

We occasionally identify specific oil and gas properties that we wish to sell. At the end of each reporting period, we evaluate properties that might be sold to determine whether any should be reclassified as held for sale. The held-for-sale criteria include: a commitment to a plan to sell; the asset is available for immediate sale; an active program to locate a buyer exists; the sale of the asset is probable and expected to be completed within one year; the asset is being actively marketed for sale; and it is unlikely that significant changes to the plan will be made. If each of these criteria is met, the property is reclassified as held for sale on our consolidated balance sheets. We also compare the fair values of the properties held for sale to the net unamortized cost. If an impairment is indicated, the assets held for sale are recorded at fair value less costs to sell and impairment expense is recorded.

Stock-Based Compensation

The Company uses the Black-Scholes option-pricing model to determine the fair-value of stock-based awards in accordance with ASC 718, "Stock Compensation." The option-pricing model requires the input of highly subjective assumptions, including the option's expected life, the price volatility of the underlying stock, and the estimated dividend yield of the underlying stock. The expected term of outstanding stock-based awards represents the period that stock-based awards are expected to be outstanding and is determined based on the contractual terms of the stock-based awards, vesting schedules and expectations of future employee behavior as influenced by changes to the terms of its stock-based awards. As there was insufficient historical data available to ascertain an expected term for these awards, the plain vanilla method was applied in calculating the expected term of the options. The Company's common stock has limited historical trading data, and as a result the expected stock price volatility is based on the historical volatility of a group of publicly-traded companies that share similar operating metrics and histories. The Company has never paid dividends on its common stock and does not intend to do so in the foreseeable future, and as such, the expected dividend yield is zero. Forfeitures are recorded as they occur.

Loans and Borrowings

Borrowings are recognized initially at fair value, net of financing costs incurred, and subsequently measured at amortized cost. Any difference between the amounts originally recorded and the redemption value of the debt is recognized as interest expense in the consolidated statements of operations over the period to maturity using the effective interest method.

Fair Value of Financial Instruments

Fair value accounting, as prescribed in ASC Section 825, "Financial Instruments," utilizes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described below:

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;
Level 2 Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability; and
Level 3 Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (supported by little or no market activity).

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

As disclosed in Note 5, the Secured Credit Facility contained embedded elements that required identification and quantification of fair value. The estimated fair values as of February 1, 2018, the closing date of the facility, are presented in Note 5. As of December 31, 2018, the estimated fair values are presented in the following table:

	December 31, 2018
Registration rights penalty derivative liability	$ (102,892)
Share purchase option derivative liability	(138,908)
	$ (241,800)

The following table presents a roll-forward of the fair value of the derivative liabilities associated with the Company's Secured Credit Facility, categorized as Level 3 for the year ended December 31, 2018. There were no comparable liabilities for the 2017 period:

	Year Ended December 31, 2018
Beginning balance	$ -
Additions (Note 5)	(1,670,017)
Gain included in earnings	1,428,217
Gain (loss) included in other comprehensive income	-
Ending Balance	$ (241,800)

Estimated Fair Value of Other Financial Assets and Liabilities

The Company's other financial instruments consist primarily of cash, accounts receivable, accounts payable, and various borrowings. Substantially all of the Company's other financial instruments are classified as current assets or current liabilities. The carrying values of current assets and current liabilities are representative of their fair values due to their short-term maturities.

Going Concern Assessment

Pursuant to Accounting Standards Update ("ASU") 2014-15, "Presentation of Financial Statements – Going Concern" the Company has assessed its ability to continue as a going concern for a period of one year from the date of the issuance of these consolidated financial statements. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity may be unable to meet its obligations as they become due within one year from the consolidated financial statement issuance date.

The uncertainty regarding the Company's ability to continue as a going concern is based on it's substantial near-term liabilities, continuing net losses and negative working capital, among other things which existed as of December 31, 2018. At December 31, 2018 the Company had a cash balance of approximately $2.6 million and other current assets of approximately $29.6 million including assets held for sale of $16.1 million, resulting in negative working capital of $32.9 million. The Company had net losses, including non-cash charges, of $17.3 million and $10.8 million for the years ended December 31, 2018 and 2017, respectively. At December 31, 2018 the Company was obligated to repay $9.4 million in principal plus accrued interest on outstanding convertible promissory notes, which payment was not made. The convertible notes are currently in default. The Company is also in default under the terms of the Secured Credit Facility (Note 5) and as a result $29.9 million, including the outstanding principal, accrued interest and penalties are due. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. Some accounts payable obligations to vendors are past the due date and some of those vendors have filed liens or indicated an intent to file liens on certain of the Company's assets. The net proceeds from the sale of the non-operated assets in February 2019 were applied by the Secured Lenders to amounts allegedly owed to them. The Company has been unable to access the debt or equity markets to obtain any additional funding during 2018.

Management has evaluated these conditions and determined that increased revenues from the Company's operated properties may allow the Company to meet its ongoing operational obligations. However, to continue to execute its business plan, and meet its debt obligations, additional working capital will be required. As part of the analysis, the Company considered selective participation in certain operated drilling programs based on availability of working capital and the timing of production-related cash flows. There is uncertainty that management's plans, if executed will allow the Company to meet all of its obligations.

As a result, there is substantial doubt about the Company's ability to continue as a going concern within one year after the date the consolidated financial statements are issued. The Company's consolidated financial statements do not include any adjustments related to the realization of the carrying value of assets or the amounts and classification of liabilities that might be necessary should the Company be unable to continue as a going concern.

Recently Adopted Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued a new standard on revenue recognition that provides a single, comprehensive model that entities will apply to determine the measurement and timing of revenue to be recognized. The underlying principle is that an entity will recognize revenue for the transfer of goods or services to customers at the amount expected to be received in exchange for those goods or services. The standard outlines a five-step approach to apply the underlying principle: (1) identify the contract with the customer, (2) identify the separate performance obligations in the contract, (3) determine the transaction price, (4) allocate the transaction price to separate performance obligations and (5) recognize revenue when or as each performance obligation is satisfied. The standard, known as Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, and all related ASU's, was adopted by the Company effective January 1, 2018. The Company adopted ASU 2014-09 using the modified retrospective transition method, which was applied to all active contracts as of January 1, 2018. The adoption of ASU 2014-09 did not result in a change to current or prior period results nor did it result in a material change to the Company's business processes, systems, or controls. However, upon adopting ASU 2014-09, the Company expanded its disclosures to comply with the expanded disclosure requirements of ASU 2014-09.

Effective January 1, 2018, the Company adopted ASU No. 2017-01, *Business Combinations (Topic 805) Clarifying the Definition of a Business* ("ASU 2017-01"). The ASU clarifies the definition of a business with the objective of adding guidance for the evaluation of whether certain transactions represent the acquisition (or disposal) of assets or business combinations. The Company adopted ASU 2017-01 on a prospective basis.

R***ecent Accounting Pronouncements*** – In February 2016, FASB issued ASU No. 2016-02, *Leases* (Topic 842). For lessees, the guidance in this update and subsequent amendments require that a company recognize most leases by recording both a lease liability and right-of-use asset on its balance sheet, representing the obligation to make payments and the right to use or control the use of a specified asset for the lease term. The standards include an exception for short term leases. Furthermore, the new lease standard does not apply to leases of mineral rights related to crude oil and natural gas. The new requirements are effective for annual periods beginning after December 15, 2018. Upon adoption, the Company will begin reflecting long-term future lease payments as both an asset and a liability on its consolidated balance sheet. The Company has elected the practical expedient provided in the standard that allows the new guidance to be applied prospectively to all new or modified land easements and rights-of-way. Based upon its preliminary analysis, the Company's implementation of this standard on January 1, 2019 resulted in an increase to total assets and total liabilities of insignificant amounts, with no adjustment to the opening balance of retained earnings (accumulated deficit).

In August 2017, the FASB issued ASU 2017-12*, Derivatives and Hedging (Topic 815),* which makes significant changes to the current hedge accounting guidance. The new standard eliminates the requirement to separately measure and report hedge ineffectiveness and generally requires the entire change in the fair value of a hedging instrument to be presented in the same line as the hedged item in the consolidated statement of operations. The new standard also eases certain documentation and assessment requirements and modifies the accounting for components excluded from the assessment of hedge effectiveness. The new standard will be adopted by the Company effective for the annual period beginning after December 15, 2018, including interim periods within that annual period. The adoption of this guidance is not expected to have a material impact on the Company's consolidated financial statements.

There are no other recently issued ASUs (issued through April 2, 2019 and not yet adopted by the Company) that are expected to have a material effect on the Company's consolidated financial statements and related disclosures when they are adopted.

NOTE 3 – PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment balances were comprised of furniture, fixtures, and equipment and are shown below:

	December 31, 2018	December 31, 2017
Property, plant and equipment	$ 223,517	$ 223,517
Accumulated depreciation	(108,167)	(55,106)
Total	$ 115,350	$ 168,411

Depreciation expense recorded for the years ended December 31, 2018 and 2017 amounted to $53,061 and $46,778, respectively.

NOTE 4 – CRUDE OIL AND NATURAL GAS PROPERTIES

The Company's crude oil and natural gas properties are located entirely within the State of Colorado in the United States of America. The net capitalized costs related to the Company's crude oil and natural gas activities were as follows:

	As of December 31, 2018	As of December 31, 2017
Proved oil and gas properties	$ 41,017,944	$ 22,144,336
Unproved oil and gas properties (1)	2,055,752	1,919,335
Wells in progress (2)	1,194,114	9,858,262
Total capitalized costs	44,267,810	33,921,963
Accumulated DDA and impairment	(14,395,458)	(2,849,374)
Net capitalized costs	$ 29,723,352	$ 31,072,589

(1) Unproved oil and gas properties represent unevaluated costs the Company excludes from the amortization base until proved reserves are established or impairment is determined.

(2) Costs from wells in progress are excluded from the amortization base until production commences.

During the years ended December 31, 2018 and 2017, DDA expense was $7.0 million and $2.8 million, respectively. As discussed below, the Company recorded impairment charges of $9.9 million and lease abandonment charges of $0.6 million during the fourth quarter of 2018.

Acquisitions and Divestitures, including Assets Held for Sale

2018 Activity

During 2018, the Company completed an asset exchange that increased its working interest in its operated producing property in exchange for cash and cancellation of joint interest billing receivables. No gain or loss was recognized on the exchange.

In June 2018, the Company executed two participation agreements with PEO whereby the Company agreed to acquire working interests in approximately 2,200 gross mineral acres for a total purchase price of $4.6 million (Note 11). The terms of the agreements allowed the Company to defer payment until December 31, 2018. As of December 31, 2018, the Company decided not to fund the agreement and recorded an abandonment charge of $0.6 million payable to PEO.

Effective June 1, 2018, the Company completed a conveyance of property in lieu of payment transaction with Providence Energy Partners III ("PEP III"), one of its lenders. The exchange conveyed the Company's working interests in four producing wells, eight wells in various stages of drilling and completion, 16 proposed wells and the underlying mineral leases (the "Ocho Assets"). The conveyance of properties represented full and final settlement of $2.1 million outstanding principal balance under the supplemental line of credit with PEP III (Note 5). PEP III is considered an affiliate of PEO. As the transaction represented the conveyance of part of an interest in a proved property and did not have a significant impact on the DDA calculation, it has been recorded as a normal retirement. The carrying cost of the oil and gas properties was $0.8 million.

During the fourth quarter of 2018, as part of the plan to divest certain properties and improve liquidity, the Company began an active program to sell certain undeveloped properties along with some producing properties operated by other companies. As the plan did not represent a strategic shift, it did not qualify for accounting treatment as a discontinued operation. The Company evaluated the six criteria for classification of assets held for sale in accordance with FASB ASC 360-10-45-9. After the evaluation of these criteria, the assets were reclassified as Assets Held for Sale as of December 31, 2018.

The proceeds from the February 27, 2019 sale of the Assets held for sale was $16.1 million after adjusting for anticipated costs to sell. As the net unamortized costs of the properties was $26.0 million, the Company recorded an impairment provision of $9.9 million for the year ended December 31, 2018. On February 27, 2019, the Company closed on the sale for price of $16.5 million, after adjustments to the purchase price for amounts owed to the buyer of approximately $8.4 million and title defects of $0.1 million offset by revenue receivable of $7.5 million and net of brokers fees of $0.3 million, net, proceeds amounted to $15.3 million which were remitted to the Company's Secured Lenders.

2017 Activity

On April 3, 2017, the Company completed an acquisition of oil and gas leases covering approximately 5,874 gross (1,462 net) acres in Adams and Weld Counties, Colorado. The seller reserved to itself all rights in the leases that exist below 50 feet above the top of the uppermost J Sand formation for those lands located in Township 7 North, Range 63 West in Weld County, Colorado. The acquisition was effective January 1, 2017. The net purchase price to the Company's retained interest in the assets, following the Company's working interest partner's 50% participation in the transaction and a reduction in purchase price due to title defects, was $1.3 million. The Company paid $0.5 million of the Company's net purchase price in cash, and $0.8 million was paid through the issuance of 450,000 shares of the Company's common stock valued at $1.80 per share.

On April 21, 2017, the Company acquired a 9.37% royalty interest covering approximately 145 net acres located in Adams County, Colorado for a net purchase price of $0.6 million following the Company's working interest partner's 50% participation in the transaction. The acquisition was effective April 1, 2017. In connection with the acquisition, the Company paid a finders' fee of 20,555 shares of common stock valued at $1.80 per share to a lease broker.

On May 9, 2017, the Company acquired 200 gross (70 net) acres in Adams County, Colorado for a net purchase price of $0.4 million following the Company's working interest partner's 50% participation in the transaction. The transaction was effective April 1, 2017.

On September 15, 2017, the Company completed a purchase of additional oil and gas leases covering approximately 400 gross (200 net) acres. The gross purchase price was $0.4 million, or $0.2 million to the Company's retained interest following the Company's working interest partner's 50% participation in the transaction. The location of the acreage is contiguous with that of the acreage acquired in the April 3, 2017 transaction described above.

Costs Incurred in Crude Oil and Natural Gas Activities. Costs incurred in connection with the Company's crude oil and natural gas acquisition, exploration and development activities for each of the years ended December 31, 2018 and 2017 are shown below:

	December 31,	
	2018	2017
Exploration and abandonment costs	$ 580,881	$ 61,693
Development costs	33,393,215	18,771,794
Acquisition of properties		
Proved	164,199	—
Unproved	342,982	4,049,380
Total	$ 34,481,277	$ 22,882,867

NOTE 5 – DEBT

The following table presents account balances and activity for our various debt instruments as of December 31:

	Initial Line of Credit	Supplemental Line of Credit	Convertible Notes 10%	Convertible Notes Series B	Secured Credit Facility
December 31, 2016 Principal Balance	**$ (5,000,000)**	**$ (7,105,000)**	**$ (1,942,600)**	**$ -**	**$ -**
December 31, 2016, Total, net	**$ (5,000,000)**	**$ (7,105,000)**	**$ (5,308)**	**$ -**	**$ -**
Principal					
Borrowings	-	-	(8,057,400)	(4,724,900)	(5,000,000)
Repayments	-	3,552,500	-	-	-
Conversions	-	-	5,166,800	-	-
Beginning Balance - Unamortized Debt Issuance Costs - Original Issuer Discount	-	-	204,703	-	-
Additions	-	-	804,750	205,211	104,871
Accretion	-	-	(742,944)	(36,887)	(1,436)
Ending - Unamortized Debt Issuance Costs - Original Issuer Discount	-	-	266,509	168,324	103,435
Beginning Balance - Unamortized Debt Issuance Costs - Beneficial Conversion Feature	-	-	1,030,762	-	-
Additions	-	-	4,272,867	56,500	-
Accretion	-	-	(3,978,881)	(11,959)	-
Ending - Unamortized Debt Issuance Costs - Beneficial Conversion Feature	-	-	1,324,748	44,541	-
Beginning Balance - Unamortized Debt Issuance Costs - Warrant Discount	-	-	701,827	-	-
Additions	-	-	2,978,791	-	-
Accretion	-	-	(2,758,537)	-	-
Ending - Unamortized Debt Issuance Costs - Warrant Discount	-	-	922,081	-	-
December 31, 2017, Principal Balance	**$ (5,000,000)**	**$ (3,552,500)**	**$ (4,833,200)**	**$ (4,724,900)**	**$ (5,000,000)**
December 31, 2017, Total, net	**$ (5,000,000)**	**$ (3,552,500)**	**$ (2,319,862)**	**$ (4,512,035)**	**$ (4,896,565)**
Principal					
Borrowings	-	-	-	-	(20,000,000)
Repayments	5,000,000	3,552,500	-	-	-
Conversions	-	-	200,000	-	-
Beginning Balance - Unamortized Debt Issuance Costs - Original Issuer Discount	-	-	266,509	168,324	103,435
Additions	-	-	-	-	4,284,416
Accretion	-	-	(266,509)	(168,324)	(1,789,664)
Ending - Unamortized Debt Issuance Costs - Original Issuer Discount	-	-	-	-	2,598,187
Beginning Balance - Unamortized Debt Issuance Costs - Beneficial Conversion Feature	-	-	1,324,748	44,541	-
Additions	-	-	-	-	2,272,775
Accretion	-	-	(1,324,748)	(44,541)	(949,372)
Ending - Unamortized Debt Issuance Costs - Beneficial Conversion Feature	-	-	-	-	1,323,403

Beginning Balance - Unamortized Debt Issuance Costs - Warrant Discount	-	-	922,081	-	-
Additions	-	-	-	-	1,538,943
Accretion	-	-	(922,081)	-	(642,797)
Ending - Unamortized Debt Issuance Costs - Warrant Discount	-	-	-	-	896,146
December 31, 2018, Principal Balance	**$ -**	**$ -**	**$(4,633,200)**	**$(4,724,900)**	**$(25,000,000)**
December 31, 2018, Total, net	**$ -**	**$ -**	**$(4,633,200)**	**$(4,724,900)**	**$(20,182,264)**

Line of credit

On May 13, 2015, the Company entered into a Revolving Line of Credit Facility Agreement ("initial line of credit", "Line of credit") with PEO, a related party, which provided the Company with a revolving line of credit of up to $5.0 million. Interest on the supplemental line initially accrued at the rate of 10% per year. On February 1, 2018 concurrent with the closing of the Secured Credit Facility (as described more fully below), the outstanding balance of $5.0 million plus accrued interest was repaid in full. In connection with the repayment, the Company recognized $0.3 million in interest expense related to the recognition of an unaccreted debt discount associated with the Line of Credit.

As of December 31, 2018, and 2017, the outstanding balance on the Line of credit was $0.0 and $5.0 million respectively. The Company had accrued interest was $0.0 and $0.5 million respectively. During the years ended December 31, 2018 and 2017, the Company recorded interest expense of $0.3 million and $0.4 million respectively, related to the initial line of credit.

Supplemental line of credit

On October 13, 2016, the Company entered into a revolving line of credit facility agreement (the "supplemental line of credit") with PEP III. PEP III is an affiliate of PEO. The supplemental line of credit permitted the Company to borrow up to $10.0 million to pay costs associated with its acquisition and development of oil and gas properties in the Wattenberg Field. Interest on the supplemental line initially accrued at the rate of 8% per year.

The supplemental line of credit was amended on March 30, 2017, pursuant to which the Company agreed not to borrow additional amounts against the supplemental line of credit and to repay $3.6 million.

On June 8, 2017, the Company entered into a letter agreement ("PEP III Agreement") with PEP III and PEO, pursuant to which PEP III agreed to modify the Company's supplemental line of credit. The PEP III Agreement extended the maturity date of the supplemental line of credit, including approximately $3.8 million in outstanding principal and accrued interest, from June 13, 2017 until December 27, 2017, and increased the interest rate on the supplemental line from 8% to 10%, effective June 8, 2017. The Company and PEO also agreed to amend the participation agreement between the Company and PEO, dated May 13, 2015 ("Participation Agreement"), in order to expand the area of mutual interest ("AMI") established and granted PEP III an option to participate under the Participation Agreement. PEP's option under the Participation Agreement expired when the line of credit was extinguished in June 2018.

On December 21, 2017 in connection with the execution of a Letter Agreement (as described more fully below) the interest rate on the supplemental line of credit was increased to 15% and the maturity date was extended until June 30, 2018.

On February 1, 2018, concurrent with the closing of the Secured Credit Facility (as described more fully below), $1.5 million of principal plus accrued interest was repaid on the supplemental line of credit.

Effective June 1, 2018, the Company and PEP III closed on a transaction to exchange the Company's interest in the Ocho Assets (Note 5) in full satisfaction of the remaining $2.1 million of outstanding principal balance on the supplemental line of credit. The Company accounted for this transaction as a retirement in accordance with ASC 932-360-40-3. As the retirement did not impact the unit-of-production amortization rate no gain or loss was recognized on the transaction.

As of December 31, 2018, and 2017, the outstanding balance on the supplemental line of credit was $0.0 and $2.1 million respectively. The Company had accrued interest of $nil and $0.5 million respectively. During the years ended December 31, 2018 and 2017, the Company recorded interest expense of $0.1 million and $0.4 million respectively, related to the supplemental line of credit.

10% Convertible Notes

On January 30, 2017, the Company completed the private placement of units consisting of convertible promissory notes ("Convertible Notes") with an aggregate face value of $10.0 million and common stock purchase warrants. The Convertible Notes are unsecured, bear interest at 10% per year and were due and payable on December 31, 2018. At the option of the holders of the Convertible Notes, the principal amount and any accrued but unpaid interest are convertible into shares of the Company's common stock at a conversion price of $1.50 per share.

The Company received net proceeds of approximately $9.0 million from the private placement, after placement agent fees and other associated expenses.

In accordance with ASC 470, "Debt", the proceeds from the sale of the Convertible Notes was allocated between the conversion feature embedded in the Convertible Notes and the warrants attached to the notes based on the fair values of the debt instrument without the warrants, and of the warrants themselves, at the time of issuance. The fair value of the beneficial conversion feature (BCF) was $5.3 million and the fair value of the warrants was $3.7 million. Each of the fair value amounts were recorded as a reduction of the carrying value of the Convertible Notes and were amortized to interest expense using the effective interest method over the term of the Convertible Notes. In addition, warrants with an estimated fair value of $1.0 million were issued to the placement agent in connection with the offering. The placement agent warrants were recorded as a charge to additional paid-in capital.

On October 16, 2017, in connection with the sales of Series B Unsecured Convertible Promissory Notes ("Series B Convertible Notes") as described more fully below, $5.2 million in principal of the Convertible Notes and $0.1 million in accrued interest was converted into 4,814,265 shares of common stock at a conversion rate of $1.10 per share. The Company has recorded a loss on conversion of $1.8 million in connection with the reduction of the initial contractual conversion rate.

As of December 31, 2018, and 2017, the Convertible Notes had an outstanding principal balance of $4.6 million and $4.8 million and accrued interest of $nil and $0.3 million respectively. Interest expense related to the notes for the years ended December 31, 2018 and 2017 was $0.5 million and $0.8 million.

The 10% Convertible Notes were not paid as of December 31, 2018, and they remain outstanding and in default.

Series B Convertible Notes

In September and October 2017, the Company sold Series B Convertible Notes in the principal amount of $4.7 million. The Series B Convertible Notes are unsecured, bear interest at 15% per year, and were due and payable on December 31, 2018. At the option of the holders, the principal amount of the Series B Convertible Notes and any accrued but unpaid interest are convertible into shares of the Company's common stock at a conversion price of $1.50 per share. The Company netted $4.5 million from the sale of the Series B Convertible Notes after expenses.

In accordance with ASC 470, the fair value of the beneficial conversion feature of $56,500 has been recorded as a reduction of the carrying value of the Series B Notes and was amortized to interest expense using the effective interest method over the term of the Series B Notes.

As of December 31, 2018, and 2017, the Series B Convertible notes had and outstanding balance of $4.7 million and $4.7 million and accrued interest of $nil and $0.2 million respectively. Interest expense related to the notes for the years ended December 31, 2018 and 2017 was $0.7 million and $0.2 million.

The Series B Convertible Notes were not paid as of December 31, 2018, and they remain outstanding and in default.

Secured Credit Facility

On February 1, 2018, the Company closed on a $25.0 million Secured Credit Facility with Providence Wattenberg, LP and 5NR Wattenberg, LLC ("Secured Lenders"). Each of Providence and 5NR are affiliates of the Lenders under a Letter Agreement entered into by the Company on December 21, 2017, under which the Company borrowed $5.0 million. The obligation under the Secured Credit Facility includes the $5 million borrowed under the Letter Agreement and includes additional borrowings of $20.0 million.

The following are the material terms of the Secured Credit Facility:

- Interest on the outstanding principal balance accrues at the base rate of 14% per year plus the greater of either 1% or US Dollar LIBOR (three-month tenor), but in no event greater than 17%, plus, in the event of default, penalty interest of 5%. Interest payments are due and payable each month commencing March 1, 2018.

- The Company paid a $1.25 million origination fee at the time of the closing and agreed to pay a $1.25 million underwriting fee on February 1, 2019.

- The borrowing is secured by a lien on all of the Company's assets.

- All principal is due February 1, 2020 ("Maturity Date").

- At any time, each Secured Lender may convert 20% of the outstanding principal balance into common stock of the Company at a conversion rate of $1.15 per share and 80% of the outstanding principal balance at a conversion rate of $1.55 per share.

- The Secured Lenders received warrants to purchase 1,500,000 shares of common stock of the Company at a price of $0.01 per share (Note 8).

- The Secured Lenders were granted the right to participate in any public or private securities offering by the Company, limited to 50% of securities offered until December 31, 2018, and 25% of any securities offered thereafter.

- Beginning on the maturity date and continuing until February 2021, the Secured Lenders were granted an option to purchase up to $25 million of the Company's common stock at a 10% discount from the 30-day volume-weighted average trading price ("VWAP") of the common stock at the time the option is exercised, but in no event shall the exercise price be less than $1.85 per share; and registration rights in connection with the common stock that may be issued upon exercise of the foregoing rights.

- The Borrower has the right to make an optional prepayment prior to the maturity date. Upon prepayment of the loan or upon certain events of default, the Company is subject to a "Make-Whole Premium" in the amount of 40% multiplied by the then-outstanding balance, less amounts paid for interest and certain fees paid by the Borrower under the Secured Credit Facility

The Secured Credit Facility is subject to certain financial and restrictive covenants under which the Company's failure to comply results in an event of default. The covenants include:

- The Company has agreed not to issue any equity securities or securities convertible into or exercisable for equity securities without the consent of Lenders, except for common stock issuable under the Company's equity incentive plan, certain registered public offerings, common stock issuable in connection with certain convertible promissory notes and certain outstanding warrants; and

- Maintenance of a Total Leverage Ratio and a Present Value of Proved Developed Producing Reserves Coverage Ratio, as defined in the borrowing documents.

The following table summarizes the use of the $20.0 million in additional borrowings under the terms of the Secured Credit Facility:

Gross Proceeds	$ 20,000,000
Payment of origination fee	(1,250,000)
Principal repayment on Initial Line of Credit	(5,000,000)
Principal repayment on Supplemental Line of Credit	(1,500,000)
Payment of accrued interest costs	(1,086,808)
Net Cash Proceeds	$ 11,163,192

The Secured Credit Facility is considered a hybrid debt instrument with several elements that required identification and valuation. As the fair value of the embedded derivatives is not readily determinable through an active marketplace of identical instruments, the Company employed the Monte Carlo simulation valuation model to determine the fair value of the embedded derivative liabilities.

It was determined that the rights to convert the debt into common shares contained a beneficial conversion feature that could be detached from the debt and valued as a component of equity. It was likewise determined that the warrants could be detached from the debt and valued as a component of equity. It was determined that the option to purchase shares at a 10% discount from VWAP represented a derivative liability that should be remeasured at fair value for each reporting period. The Company further determined that certain provisions of the agreement which provide for additional interest payments under certain conditions represent an additional compound derivative liability that should also be remeasured at fair value for each reporting period. The compound derivative liability included the Make-Whole Premium, Default Interest Penalty, and Registration Rights Penalty. For both the share purchase option and the additional interest provisions, a Monte Carlo simulation model was used to calculate estimates of fair value. The model was used as of February 1, 2018 to determine the initial valuation. In each interim reporting period subsequent to February 1, 2018, the model was updated to determine changes in the estimated values.

The values allocated to each component of the debt instrument are set forth below;

Secured Credit Facility, net of all discounts	$ 16,786,981
Make whole premium derivative liability	14,698
Default interest penalty derivative liability	243,794
Registration rights penalty derivative liability	63,672
Share purchase option derivative liability	1,347,853
Stock purchase warrants	1,538,943
Beneficial conversion feature	2,272,775
Legal fees and other	231,284
Subtotal	22,500,000
Origination fee and Underwriting fee	2,500,000
Secured Credit Facility, face value	$ 25,000,000

Defaults

As of December 31, 2018, the Company was in default under certain provisions of the Secured Credit Facility including the inability of the Company to pay its debts or other obligations as they become due, a mechanic's lien filed against the Company in Adams, County Colorado and for accounts payable outstanding for greater than 90 days. On February 1, 2019, the Company incurred another event of default by failing to pay the Secured Lenders a $1.3 million underwriting fee incurred in connection with the origination of the Secured Credit Facility.

As a result of the defaults, the Company has accrued additional default penalty interest of $0.3 million at the penalty interest rate of an additional 5%, from the date of the first reported default on October 1, 2018 through December 31, 2018. The Company has accrued $3.4 million related to the embedded make-whole premium.

As of December 31, 2018, $29.9 million in principal, penalty interest and amounts accrued for the make-whole premium are due and payable. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. The Notice declared that all amounts outstanding were immediately due and payable.

The Company is currently in negotiation with the Secured Lenders as to the impact and resolution of the defaults.

NOTE 6 – ASSET RETIREMENT OBLIGATION

For the purpose of determining changes in the amount of the asset retirement obligation during the year ended December 31, 2018, the Company assumed an inflation rate of 2% and a credit-adjusted risk-free interest rate ranging from approximately 14% to 21%. For the year ended December 31, 2017, the Company assumed an inflation rate of 2% and a credit-adjusted risk-free rate ranging from approximately 11% to 14%. For both years, assumed well lives are based upon engineering and economic data and approximate 30 years for new horizontal wells and shorter lives for the acquisition of older wells.

The following table presents changes in the asset retirement obligation for the years ended:

	December 31,	
	2018	2017
Asset retirement obligation, beginning of year	$ 1,123,444	$ 945,419
Liabilities settled (1)	(192,996)	(50,163)
Liabilities incurred	58,511	91,999
Revisions in estimated cash flows	983,352	36,507
Accretion	117,636	99,682
Asset retirement obligation, end of year	$ 2,089,947	$ 1,123,444
Current liability	$ 843,796	$ 288,784
Long-term liability	$ 1,246,151	$ 834,660

(1) Reflects liabilities settled through plugging and abandonment activities and divestitures of properties.

The revisions in estimated cash flows during 2018 were primarily due to changes in estimates of costs for labor and materials related to the plugging and abandonment of wells and the shortening of the estimated lives of wells.

NOTE 7 - ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities were comprised of the following amounts:

	December 31,	
	2018	2017
Trade payables and accrued liabilities	$ 2,093,428	$ 1,544,112
Accrued interest payable	-	876,455
Liabilities incurred in connection with acquisition of crude oil and natural gas properties	22,291,989	1,719,785
Total	$ 24,385,417	$ 4,140,352

See Note 11 for related party liabilities.

NOTE 8 - SHAREHOLDERS' EQUITY

Increase in share capital

On March 15, 2019, at a special meeting, the shareholders approved an amendment to the Company's Articles of Incorporation ("Amendment") to increase the authorized common stock from 100,000,000 shares to 200,000,000 shares. The Amendment was effective on March 20, 2019 upon filing with the Colorado Secretary of State.

Common Stock

As of December 31, 2018, and 2017, the Company had 100,000,000 shares of common stock authorized with a par value of $0.001 per share. As of December 31, 2018, and 2017, the Company had 28,089,765 and 27,718,802 shares issued and outstanding, respectively.

Activity for the year ended December 31, 2018 included the following:

On February 23, 2018 the Company issued 70,000 shares of common stock, valued at $1.00 per share, in lieu of cash compensation.

On March 12, 2018 the Company issued 135,963 shares of common stock in connection with the conversion of $200,000 of 10% convertible notes payable plus accrued interest. The shares were issued at the contractual rate of $1.50.

On April 18, 2018 the Company issued 75,000 shares of common stock, valued at $1.23 per share, in connection with the appointment of three new members to its Board of Directors.

On June 1, 2018 the Company issued 65,000 shares of common stock valued $1.40 per share to employees of the Company as compensation. The shares are subject to certain vesting restrictions, but all 65,000 shares have full voting rights and are eligible to receive dividends during the vesting period.

On July 24, 2018 the Company issued 45,000 shares of common stock valued at $1.29 per share to an officer of the Company as compensation. The shares are subject to certain vesting restrictions, but all 45,000 shares have full voting rights and are eligible to receive dividends during the vesting period.

Activity for the year ended December 31, 2017 included the following:

- On October 16, 2017, the Company issued 4,814,265 shares of common stock valued at $1.38 in conversion of $5.2 million of Convertible Notes and $0.1 million in accrued interest (Note 5).

- On September 23, 2017, the Company issued 250,000 shares of common stock valued at $1.55 to PEO in connection with the execution of a Letter Agreement.

- On various dates, in connection with the execution of four employment agreements and the employment of additional employees, the Company issued 219,700 shares of restricted stock. The shares are subject to certain vesting restrictions, but all 219,700 shares have full voting rights and are eligible to receive dividends during the vesting period.

- On April 3, 2017, the Company issued 470,555 shares valued at $1.80 per share in connection with the acquisitions of oil and gas assets.

Preferred Stock

As of December 31, 2018, and 2017, the Company had 10,000,000 shares of preferred stock authorized with a par value of $0.01 per share. As of December 31, 2018, and 2017, there were no shares of preferred stock issued or outstanding.

Warrants

The table below summarizes warrants outstanding as of December 31, 2018:

	Shares Underlying Outstanding Warrants	Exercise Price Per Share	Expiration Date
Underwriter warrants	255,600	$ 1.25	11/12/2020
Investor warrants	6,666,600	$ 3.00	12/31/2019
Placement agent warrants	666,600	$ 1.50	12/31/2021
Secured Credit Facility warrants	1,500,000	$ 0.01	02/01/2020
Total	9,088,800		

Activity for the year ended December 31, 2018 included the following:

On February 1, 2018 in connection with the closing of the Secured Credit Facility, the Company issued 1,500,000 stock purchase warrants. The warrants are exercisable at $0.01 per share and expire on February 1, 2020 (Notes 5).

Activity for the year ended December 31, 2017 included the following:

- On January 20, 2017 and January 30, 2017, the Company issued 537,260 warrants exercisable at $1.50 per share and expiring on December 31, 2021 in connection with a private placement (Note 5).

- On January 20, 2017 and January 30, 2017, the Company issued 5,371,579 warrants exercisable at $3.00 per share and expiring on December 31, 2019, also in connection with the private placement (Note 5).

NOTE 9 – STOCK-BASED COMPENSATION

On August 18, 2016, the Company's Board of Directors adopted the Amended and Restated PetroShare Corp. Equity Incentive Plan (the "Plan"). The Plan terminates on August 17, 2026. Among other things, the Plan increased the number of shares of common stock reserved for issuance thereunder from 5,000,000 to 10,000,000 shares. The Company's shareholders approved the Plan at the Company's annual meeting of shareholders on September 8, 2016.

During the year ended December 31, 2018, the Board of Directors granted non-qualified options to employees, directors and consultants of the Company under the Plan to acquire 790,000 shares of common stock.

A summary of activity under the Plan for the years ended December 31, 2018 and 2017 is as follows:

	Number of Shares	Weighted Average Exercise Price	Remaining Contractual Term (Years)
Outstanding, December 31, 2016	4,675,000	$ 0.76	5.39
Granted	422,000	$ 1.86	5.69
Exercised	—	—	—
Forfeited	(100,000)	—	—
Outstanding, December 31, 2017	4,997,000	$ 0.85	4.44
Exercisable, December 31, 2017	4,347,500	$ 0.74	4.48
Granted	790,000	0.93	4.07
Exercised	—	—	—
Expired	(425,000)	1.00	—
Forfeited	(325,000)	1.35	3
Outstanding, December 31, 2018	5,037,000	$ 0.79	3.87
Exercisable, December 31, 2018	4,621,000	$ 0.75	3.86

The fair value of each stock-based award was estimated on the date of the grant using the Black-Scholes pricing model that incorporates key assumptions including volatility of the Company's stock, dividend yield and risk-free interest rates. As the Company's common stock has limited historical trading data, the expected stock price volatility is based primarily on the historical volatility of a group of publicly-traded companies that share similar operating metrics and histories. The expected term of the awards represents the period of time that management anticipates awards will be outstanding. As there was insufficient historical data available to ascertain an expected term, the plain vanilla method was applied in calculating the expected term of the options. The risk-free rates for the periods within the contractual life of the options are based on the US Treasury bond rate in effect at the time of the grant for bonds with maturity dates at the expected term of the options. The Company has never paid dividends on its common stock and currently does not intend to do so, and as such, the expected dividend yield is zero. Compensation expense related to stock options was recorded net of actual forfeitures.

The table below summarizes assumptions utilized in the Black-Scholes pricing model for the years ended 2018 and 2017:

	December 31, 2018	December 31, 2017
Expected option term—years	2.0-3.0	2.5 - 3.25
Risk-free interest rate	2.58%-2.81%	1.75%-1.93%
Expected dividend yield	—	—
Volatility	85%-100%	162% - 169%
Forfeited	—	—

During the years ended December 31, 2018 and 2017, the Company recorded stock-based compensation related to options of $0.7 million, and $1.4 million, respectively. Unvested stock-based option compensation at December 31, 2018 amounted to $0.1 million.

NOTE 10 – PROVISION FOR INCOME TAXES

The Company has analyzed filing positions in all of the federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in these jurisdictions. No uncertain tax positions have been identified as of December 31, 2018.

The Company is in a position of cumulative reporting losses for the current and preceding reporting periods. The volatility of energy prices is not readily determinable by management. At this date, this fact pattern does not allow the Company to project sufficient sources of future taxable income to offset tax loss carry-forwards and net deferred tax assets. Under these circumstances, it is management's opinion that the realization of these tax attributes does not reach the "more likely than not criteria" under ASC 740, "Income Taxes." As a result, the Company's deferred tax assets as of December 31, 2018 and 2017 are subject to a full valuation allowance.

Net deferred tax assets and liabilities consist of the following components as of December 31, 2018 and 2017:

	Year Ended December 31,	
	2018	**2017**
Deferred tax assets - noncurrent:		
NOL carryover$	5,385,347	$ 2,109,423
Stock based compensation	727,631	727,631
Asset retirement obligation	515,333	277,015
Charitable contribution	814	814
Allowance for doubtful accounts	29,321	—
Total deferred tax assets	$ 6,658,446	$ 3,114,883
Deferred tax liabilities - current:		
Property and equipment	(9,405)	(15,251)
Impairment, intangible drilling costs and other exploration costs capitalized	(1,205,247)	(935,482)
Debt discount - Beneficial conversion feature	(326,321)	(337,518)
Derivative liabilities	(352,165)	—
Total deferred tax liabilities	(1,893,138)	(1,288,251)
Net deferred tax assets	4,765,308	1,826,632
Valuation allowance	(4,765,308)	(1,826,632)
Net deferred tax assets	$ —	$ —

The income tax provision differs from the amount of income tax determined by applying the US federal tax rate to the pretax loss from continuing operations for the years ended December 31, 2018 and 2017 due to the following:

	Year Ended December 31,	
	2018	2017
Tax at statutory federal rate	$ (3,634,627)	$ (3,688,109)
Permanent difference	836,035	2,258,353
State taxes, net of federal	(519,052)	(331,474)
Change in valuation allowance	3,499,090	396,256
Effect of the Tax Cuts and Jobs Act	—	918,446
Other	(181,446)	446,528
Provision (benefit) for income taxes	$ —	$ —

At December 31, 2018, the Company had net operating loss carry-forwards of approximately $21.8 million that may be offset against future taxable income from the years 2019 through 2038.

Due to the change in ownership provisions of the Tax Reform Act of 1986, net operating loss carry-forwards for federal income tax reporting purposes are subject to annual limitations. Should a change in ownership occur, net operating loss carry-forwards may be limited as to use in future years.

The Company files income tax returns in the US federal jurisdiction and in the State of Colorado. The Company is currently subject to US federal, state and local income tax examinations by tax authorities since inception of the Company.

ASC 740 requires the recognition of the tax effects of the of the Act for annual periods that include December 22, 2018. At December 31, 2018, the Company has made reasonable estimates of the effects on its existing deferred tax balances. The Company has remeasured certain federal deferred tax assets and liabilities based upon the rates at which they are expected to reverse in the future, which is generally 21 percent. The provisional amount recognized related to the remeasurement of its federal deferred tax balance was approximately $1.9 million, which was subject to a valuation allowance at December 31, 2018.

The Company will continue to analyze the Tax Act and future IRS regulations, refine its calculations and gain a more thorough understanding of how Colorado is implementing this new law. This further analysis could potentially affect the measurement of deferred tax balances or potentially give rise to new deferred tax amounts.

NOTE 11 – RELATED PARTY TRANSACTIONS

PEO

The table below summarizes related party balances with PEO and its affiliates as of December 31:

	December 31,	
	2018	2017
Liabilities		
Revenue distribution payable and accrued liabilities	$ (2,133,622)	$ (589,496)
Initial line of credit	-	(5,000,000)
Secured Credit Facility	(25,000,000)	(5,000,000)
Loan commitment fee – Secured Credit Facility	(1,250,000)	-
Default penalty interest – Secured Credit Facility	(312,500)	-
Make-whole premium Secured Credit Facility	(3,347,874)	-
Break-up fee payable, participation agreement	(580,881)	-
Assets		
Accounts receivable – joint interest billing	1,158,213	204,730

Initial Line of Credit

As of December 31, 2018, there was no balance outstanding on the initial line of credit. As of December 31, 2017, the Company had an outstanding balance of $5.0 million and had accrued interest in the amount of $0.5 million. The outstanding principal balance of $5.0 million and accrued interest of $0.5 million were repaid on February 1, 2018 with proceeds from the closing of the Secured Credit Facility. Interest expense of $0.3 million was recognized related to the note and accretion of unamortized debt discount during the year ended December 31, 2017.

Secured Credit Facility

On February 1, 2018, the Company entered a Secured Credit Facility (Note 5) pursuant to which the Company borrowed $25 million from PEO affiliated entities.

As of December 31, 2018, PEO beneficially owns approximately 11.6% of the Company's outstanding common stock. As of December 31, 2018, included in accounts payable and accrued liabilities – related party are $1.3 million in underwriting fees payable which were due on February 1, 2019. Interest expense of $7.5 million was recognized related to the note and the accretion of debt discounts during the year ended December 31, 2018.

In connection with the execution of the Secured Credit Facility, the Company issued 1.5 million warrants to purchase common stock of the Company to PEO affiliated entities (Note 8).

As of December 31, 2018, the Company was in default with certain provisions of the Secured Credit Facility including the inability of the Company to pay its debts or other obligations as they become due, mechanics liens filed against the Company in Adams County, Colorado and for in occurrence of prohibited new debt related to accounts payable outstanding for greater than 90 days. On February 1, 2019 the Company incurred another event of default by failing to pay the Senior Secured Lender a $1.3 million underwriting fee incurred in connection with the origination of the Secured Credit Facility in February 2018. As a result of the defaults, the Company has accrued additional penalty interest of $0.3 million at the penalty interest rate of 5%, from the date of the first reported default October 1, 2018 through December 31, 2018. The Company has accrued $3.4 million related to the embedded make-whole premium, which, per the Agreement, is triggered upon the event of default. As of December 31, 2018, $29.9 million in principal, penalty interest, underwriting fee payable and amounts accrued for the make-whole premium are due and payable. On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. From December 31, 2018, until April 2, 2019, the Company was in negotiations with Secured Lenders to resolve the events of default, the negotiations continue. Accordingly, the Company did not retroactively accelerate the accretion of debt discounts recorded in connection with the Secured Credit Facility.

Operations/PEO

At December 31, 2018, the Company has recorded $1.1 million in Accounts receivable – joint interest billing – related party. This amount relates to amounts billed and unbilled to PEO related to its participation in the Company's operated Shook drilling program and PEO's ownership interest in the vertical wells that the Company operates.

At December 31, 2018, the Company has recorded $1.8 million in royalties and revenue distribution payable to a related party. This amount relates to undistributed revenue from Company's operated Shook pad and vertical wells.

At December 31, 2018, the Company has recorded $0.6 million in abandonment costs payable, related to the Company's election not to participate in a participation agreement related to the acquisition of leasehold acreage (Note 4).

Convertible Notes

In January 2017, the Company sold 10% Convertible Notes to a total of four employees and directors who collectively purchased 10% Convertible Notes in the aggregate principal amount of $0.2 million (Note 5), on the same terms and conditions as the other purchasers.

On October 16, 2017, ten of the Company's officers and directors converted 10% Convertible Notes in the aggregate principal amount of $0.7 million and accrued interest of $20,670 into 691,516 shares of common stock at $1.10 per share (Note 5).

As of December 31, 2018, and 2017, the principal balance of the 10% Convertible Notes payable to employees and officers amounted to $80,000 and $80,000 respectively.

Employees, officers and directors of the Company received cash interest payments $8,000 and $0.1 million related to 10% Convertible Notes during the years ended December 31, 2018 and 2017.

Series B Convertible Notes

In September and October 2017, the Company sold Series B Convertible Notes to ten of the Company's officers and directors who collectively purchased $0.6 million in aggregate principal amount (Note 5), on the same terms and conditions as the other purchasers, with the exception that the Company did not pay commissions on these sales. Employees, officers and directors received cash interest payments of $0.1 million and $0.1 million during the years ended December 31, 2018 and 2017. As of December 31, 2018 and 2017, the outstanding principal balance of the Series B Convertible Notes payable to employees and directors amounted to $0.6 million and $0.6 million respectively.

NOTE 12 – COMMITMENTS AND CONTINGENCIES

Operating Lease

The Company leases its office facilities under a four-year non-cancelable operating lease agreement expiring in March 2021. The following is a schedule by year of future minimum rental payments required under the operating lease agreement:

Year ending December 31,	Amount
2019	$ 133,698
2020	137,658
2021	34,662
Total	$ 306,018

Lease expense totaled $0.1 million and $0.1 for the years ended December 31, 2018 and December 31, 2017, respectively.

NOTE 13 – SUBSEQUENT EVENTS

On February 27, 2019, the Company completed the sale of nearly all its non-operated oil and natural gas assets. The assets sold include all non-operated horizontal wells in which the Company had an interest, as well as the leases on which those wells are located, oil, natural gas and other hydrocarbons produced from the leases on or after the effective date of the sale, related equipment, machinery, fixtures and other personal property, surface rights and contracts. The effective date of the sale was January 1, 2019. The net purchase price received for the assets was approximately $15.3 million in cash, net of closing costs, adjustments and broker's fees. The proceeds of the sale have been applied the Secured Lenders against amounts allegedly owed under the Secured Credit Facility. See Note 4 for description of the impact of this sale on the December 31, 2018 consolidated financial statements.

On March 15, 2019, at a special meeting, the shareholders approved an amendment to the Company's Articles of Incorporation ("Amendment") to increase the authorized common stock from 100,000,000 shares to 200,000,000 shares. The Amendment was effective on March 20, 2019 upon filing with the Colorado Secretary of State.

On March 22, 2019, three members of the Board of Directors provided notice of their resignation from the Board. The resignations of Michael Allen, Joseph Drysdale and Cullen Schaar were effective immediately. None of the resignations expressed any disagreement with either the Company or its Board of Directors. At this time, the Board of Directors plans to continue its work with a reduced membership of six directors.

On April 2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility.

NOTE 14 – UNAUDITED CRUDE OIL AND NATURAL GAS RESERVES INFORMATION

The estimate of reserves at December 31, 2018, presented below, were prepared by the independent engineering firm Cawley, Gillespie & Associates Inc. All reserves are located within the DJ Basin. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGLs which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Analysis of Changes in Proved Reserves. Estimated quantities of proved developed reserves (all of which are located within the United States), as well as the changes in proved developed reserves during the periods indicated, are presented in the following tables:

	Oil (Bbls)	Natural Gas (Mcf)	NGL's (Bbls)	Total (BOE)
Balance as of December 31, 2016	2,761,204	11,492,855	1,631,188	6,307,868
Revisions of previous estimates	(388,211)	292,477	38,668	(300,797)
Extensions and discoveries	839,738	4,183,757	631,149	2,168,180
Sales of reserves in place	—	—	—	—
Improved recovery	—	—	—	—
Purchase of reserves	—	—	—	—
Production	(188,529)	(549,846)	(50,111)	(330,281)
Balance as of December 31, 2017	3,024,202	15,419,243	2,250,894	7,844,970
Revisions of previous estimates	569,936	3,444,889	(877,172)	266,912
Extensions and discoveries	36,858	244,043	—	77,532
Sales of reserves in place	(150,554)	(820,564)	(97,396)	(384,710)
Improved recovery	—	—	—	—
Purchase of reserves	678	18,533	222	3,988
Production	(287,984)	(773,396)	(66,986)	(483,870)
Balance as of December 31, 2018	3,193,136	17,532,748	1,209,562	7,324,822
Proved Developed Reserves, included above				
Balance as of December 31, 2016	260,284	1,788,895	181,655	740,088
Balance as of December 31, 2017	521,354	3,752,330	387,430	1,534,172
Balance as of December 31, 2018	1,187,985	6,300,116	672,725	2,910,729
Proved Undeveloped Reserves, included above				
Balance as of December 31, 2016	2,500,920	9,703,960	1,449,533	5,567,780
Balance as of December 31, 2017	2,502,847	11,666,911	1,863,465	6,310,797
Balance as of December 31, 2018	2,005,151	11,232,632	536,837	4,414,093

The values for the 2018 oil, natural gas and NGL reserves are based on the twelve-month arithmetic average of the first day of the month prices for the period from January through December 31, 2018. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months was $65.56 per barrel (West Texas Intermediate price) for crude oil and NGLs and $3.10 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2018 was $59.23 per barrel for oil, $3.64 per Mcf for natural gas and $24.28 per barrel for NGLs.

The values for the 2017 oil, natural gas and NGL reserves are based on the twelve-month arithmetic average of the first day of the month prices for the period from January through December 31, 2017. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months was $51.34 per barrel (West Texas Intermediate price) for crude oil and NGLs and $2.98 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2017 was $45.03 per barrel for oil, $1.71 per Mcf for natural gas and $20.42 per barrel for NGLs.

The values for the 2016 oil, natural gas and NGL reserves are based on the twelve-month arithmetic average of the first day of the month prices for the period from January through December 31, 2016. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months was $42.75 per barrel (West Texas Intermediate price) for crude oil and NGLs and $2.48 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2016 was $34.09 per barrel for oil, $2.69 per Mcf for natural gas and $14.44 per barrel for NGLs.

For the year ended December 31, 2018, the Company reported extensions and discoveries of 77,532 BOE primarily from the recognition of reserves associated with new wells drilled by its working interest partners. There were also revisions to previous estimates to reflect net upward revisions of 266,912 BOE, primarily from the improved economics provided by the increased hydrocarbon pricing, somewhat offset by a negative revision in NGL quantities as certain previous engineering estimates were adjusted for revised production information received during 2018.

For the year ended December 31, 2017, the Company reported extensions and discoveries of 2,168,180 BOE primarily as result of the conversion of 18 PUD locations in the Todd Creek Farms prospect area during 2017 coupled with the addition of new PUD locations due to economic field extensions adjacent to Company leases. The Company reported downward revisions of previous estimates of 300,797 BOE primarily related to the removal of uneconomic PUD locations.

For the year ended December 31, 2016, the Company reported extensions and discoveries of 6,030,624 BOE as a result of drilling and completion activities during 2016. Additionally, during 2016 the Company purchased reserves of 287,999 BOE.

Standardized Measure of Estimated Discounted Future Net Cash Flows to Proved Oil and Natural Gas Reserves (in thousands):

The Company follows the guidelines prescribed in ASC 932, Extractive Activities-Oil and Gas for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil, natural gas and NGL reserve disclosures, standardized measures of discounted future net cash flows from proved oil, natural gas and NGL reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company's interest in oil and gas properties as of December 31, of the years presented. These estimates were prepared by Cawley Gillespie & Associates, Inc., independent petroleum engineers.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (1) estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions; (2) the estimated future cash flows are compiled by applying the twelve-month average of the first-day-of-the-month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves; (3) the future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred; and (4) future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following summary sets forth the Company's estimated future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure prescribed in ASC 932, Extractive Activities-Oil and Gas (in thousands):

	For the years ended December 31,		
	2018	**2017**	**2016**
Future cash inflows	$ 282,293	$ 208,459	$ 148,596
Future cash outflows:			
Production cost	(81,432)	(48,929)	(35,038)
Development cost	(53,980)	(58,784)	(37,667)
Future income tax	(21,534)	(16,006)	(5,802)
Future net cash flows	125,347	84,740	70,089
Adjustment to discount future annual net cash flows at 10%	(42,237)	(35,054)	(29,925)
Standardized measure of discounted future net cash flows	$ 83,110	$ 49,686	$ 40,164

The following are the principal sources of change in the standardized measure (in thousands):

Changes in Standardized Measure of Estimated Discounted Future Net Cash Flows

	For the years ended December 31,		
	2018	**2017**	**2016**
Standardized measure, beginning of year	$ 49,686	$ 40,164	$ —
Sales of oil and gas, net of production cost	(18,270)	(9,392)	(126)
Net change in sales prices, net of production cost	35,308	10,263	489
Discoveries, extensions and improved recoveries	1,289	11,979	76,445
Change in future development costs	(2,497)	(4,050)	(37,667)
Development costs incurred during the period that reduced future development cost	19,415	1,144	—
Sales of reserves in place	(3,048)	—	—
Revisions of quantity estimates	2,867	(559)	—
Accretion of discount	5,908	4,275	130
Net change in income tax	(4,292)	(6,810)	(2,587)
Purchase of reserves	15	—	6,021
Changes in timing of rates of production	(3,271)	2,672	(2,541)
Standardized measure, end of year	$ 83,110	$ 49,686	$ 40,164

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

NONE

ITEM 9A. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Rules 13a-15(b) and 15d-15(b) under the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below under paragraph (b) within Management's Annual Report on Internal Control over Financial Reporting, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018, based on the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control-Integrated Framework (2013) ("Framework"). Based on this assessment, management concluded that our internal control over financial reporting as of December 31, 2018, was effective with the exception of the material weakness described below. A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is reasonable possibility that a material misstatement in our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

During the quarter ended March 31, 2018, we did not maintain effective controls over the accounting for a derivative liability embedded in our Secured Credit Facility, specifically, the process level controls over the calculation of the Share Purchase Option derivative liability failed to detect a mathematical error in the calculation of the fair value of the Share Purchase Option derivative liability as of February 1, 2018 and March 31, 2018. Management's review of the fair value estimate of the Share Purchase Option derivative liability was not effectively designed during that period to identify the misstatement. This control deficiency resulted in a material misstatement of the aforementioned account and disclosures to the consolidated financial statements was not prevented or detected in a timely manner. Accordingly, we have determined that this control deficiency constituted a material weakness.

This deficiency resulted in the understatement of the fair value of the Share Purchase Option derivative liability as recorded. This error was identified by management and was corrected prior to the issuance of our consolidated financial statements as of and for the quarters ended June 30, 2018, September 30, 2018 and as of and for the year ended December 31, 2018. We therefore believe that the material weakness that existed at March 31, 2018 was remediated prior to the issuance of our December 31, 2018 consolidated financial statements.

Changes in Internal Control Over Financial Reporting

The changes described below were made to our internal control over financial reporting during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In connection with the evaluation of internal control over financial reporting as of December 31, 2018, we identified that a material weakness in internal control over financial reporting existed relating to the design and operating effectiveness of controls over the calculation of the fair value of the Share Purchase Option derivative liability.

To address this material weakness in our internal control over financial reporting, we implemented the following:

- We designed and implemented additional controls around the review of the Share Purchase Option derivative liability.

- We engaged an independent consulting firm to review the fair value calculation of the Share Purchase Option derivative liability and other embedded derivatives contained in our Secured Credit Facility.

We have completed the documentation and testing of the design and operating effectiveness of the corrective actions described above and hasveconcluded that the material weakness related to the calculation of the Share Purchase Option derivative liability that existed as of March 31, 2018 was remediated prior to issuance of the consolidated financial statements as of and for the year ended December 31, 2018.

There were no changes in our internal control over financial reporting during our fiscal quarter ended December 31, 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, except as noted above.

Inherent Limitations Over Internal Controls

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of Directors and Executive Officers

Our executive officers and directors as of April 3, 2019 and their respective ages, positions, and biographical information are set forth below:

Name	Age	Positions with the Company	Board or Executive Officer Position Held Since
Bill M. Conrad	62	Chairman of the Board of Directors	November 2012
Stephen J. Foley	65	Chief Executive Officer and Director	November 2012
Frederick J. Witsell	60	President and Director	November 2012
Paul D. Maniscalco	49	Chief Financial Officer	January 2016
William B. Lloyd	60	Chief Operating Officer	January 2016
Scott C. Chandler	57	Director	May 2016
James H. Sinclair	56	Director	May 2016
Douglas R. Harris	65	Director	July 2016

Each of our directors is serving a term which expires at the next annual meeting of our shareholders and until his successor is elected and qualified or until he resigns or is removed.

The following information summarizes the business experience of each of our officers and directors for at least the last five years:

Bill M. Conrad, Chairman. Mr. Conrad has served as Chairman of our Board of Directors since our inception. He is presently an independent consultant, providing financial management services. From January 1990 until December 2012, Mr. Conrad served as the Vice-President, Chief Financial Officer and Director of MCM Capital Management, Inc., or MCM, a privately-held financial and management consulting firm. MCM assisted other companies in developing and implementing their business plans and capital formation strategies. In that capacity, Mr. Conrad participated in the organization or development of a number of companies in industries as diverse as oil and gas, real estate, and technology. From 2006 to the present, Mr. Conrad has served as a director of Gold Resource Corporation (NYSE American: GORO), a publicly-traded gold and silver mining and exploration company, and since 2014 has served as Chairman of the Board. From May 2005 to March 2016, Mr. Conrad served as a director of Synergy Resources Corporation (NYSE American: SYRG), a publicly traded oil and gas exploration and production company. Mr. Conrad's extensive experience as a director of other extraction companies and experience in capital market transactions makes him a valuable asset in connection with the growth and development of our company. For these reasons, we believe Mr. Conrad is qualified to serve as a director of our company.

Stephen J. Foley, Chief Executive Officer and Director. Mr. Foley has served as our Chief Executive Officer since our inception. Prior to entering private business, Mr. Foley had a successful professional football career as a safety with the Denver Broncos football organization of the National Football League where he played for 11 seasons, from 1976 to 1986. In 1991, Mr. Foley founded and continues to serve as the president of FSI Development Inc., a privately-held construction and development company engaged in residential development and construction. In 2000, he founded and continues to serve as a managing member of FS Land, LLC, a privately-held real estate development company. He holds a B.S. in Business Administration from Tulane University and serves on the Board of Denver Street Schools. Mr. Foley has extensive knowledge of our operations and of developing companies. For these reasons, we believe Mr. Foley is qualified to serve as a director of our company.

Frederick J. Witsell, President and Director. Mr. Witsell became our President in November 2012 and assumed the role of Secretary in August 2013. Mr. Witsell has over 37 years of experience in several facets of the oil and gas industry, including prospect development, conventional and horizontal drilling and completion operations, project management, gathering and compression systems, and marketing and risk management. From July 2011 to September 2012, Mr. Witsell served as the owner and General Manager of Premier Energy Supply, LLC, a consulting service firm in the oil and gas industry. From 2010 to 2011, Mr. Witsell served as Vice-President and General Manager of Monroe Gas Storage, an affiliate of High Sierra Energy Partners, and led the organization's projects and eventual divestiture in 2011. From 1999 to 2003, he was with Markwest Hydrocarbons (NYSE: MPLX) in the capacity of Vice-President of the Rocky Mountain Business Unit and responsible for the growth through capital programs and financial performance of the company's oil and gas operations in the United States and Canada. Mr. Witsell led the acquisition and eventual divestiture process of Markwest oil and gas assets. Prior to 1999 and at various times between 2003 and 2010 and in 2012, Mr. Witsell also served as an executive and co-founder of a series of small, privately-funded oil and gas companies with properties in North Dakota, Wyoming, Utah and Colorado. He was responsible for the growth and execution of capital programs, utilizing modern horizontal / directional drilling and completion technologies. He led the divestiture of these oil and gas companies. Mr. Witsell has a B.A. in Geology from Colorado College, an M.B.A. in Energy Management from the University of Denver, and is a member of Society of Petroleum Engineers, the American Association of Petroleum Geologists and the Rocky Mountain Association of Geologists. Our Board of Directors believes that Mr. Witsell is well qualified to serve as a director and executive officer of the company as a result of his extensive oil and gas industry experience including in areas of executive management and operations developed by serving as an executive officer of other oil and gas companies throughout his career. Mr. Witsell brings years of hands-on experience with oil and natural gas companies in many capacities and across multiple basins. For these reasons, we believe Mr. Witsell is qualified to serve as a director of our company.

Paul D. Maniscalco, Chief Financial Officer. Mr. Maniscalco became our Chief Financial Officer in January 2016. Mr. Maniscalco has been a principal with SJM Holdings, Inc., d/b/a SJM Accounting, Inc., an accounting and business advisory services firm headquartered in Englewood, Colorado, since 2008. From 2012 until 2014, Mr. Maniscalco served as interim Chief Financial Officer of Earthstone Energy Inc. (NYSE American: ESTE), a company engaged in the oil and gas industry. From 2010 until 2011, Mr. Maniscalco served as the interim Chief Financial Officer of GeoPetro Resources Company, a company engaged in the oil and gas industry with securities formerly traded on AMEX and currently traded on OTC Pink of OTCMarkets. Prior to joining SJM Accounting, Inc., Mr. Maniscalco was a senior manager for several accounting firms. Mr. Maniscalco holds a B.B.A. in Accounting and a B.H.S. in Healthcare Administration, each from Florida Atlantic University.

William B. Lloyd, Chief Operating Officer. Mr. Lloyd became our Chief Operating Officer in January 2016. Mr. Lloyd has over 37 years of experience in the oil and gas industry, serving in engineering, management, and senior leadership capacities. Prior to joining the Company, from 2007 until 2015, Mr. Lloyd served as the Senior Vice President of Operations for Cirque Resources L.P. ("Cirque"), a company engaged in the oil and gas industry. From 2006 until 2007, Mr. Lloyd served as the Western Region Drilling Manager for El Paso Exploration Company, which has oil and gas exploration and drilling operations in the Uintah Basin, Powder River Basin, and the Raton Basin. From 2002 until 2006, Mr. Lloyd served as Operations Director for ConocoPhillips Norway, during which time Mr. Lloyd managed well operations on multiple fixed platforms and exploratory drilling operations. Mr. Lloyd holds a Bachelor of Science in Petroleum Engineering from Montana Tech of the University of Montana.

Scott C. Chandler, Director. Mr. Chandler joined our Board of Directors in May 2016. Mr. Chandler has over 25 years of senior executive level management experience. He is the founder and owner of Franklin Court Partners, Inc., or FCP, an entity that provides management and financial consulting services in connection with developing business plans, securing financing and restructuring, a position he has held since 2002. Prior to founding FCP, Mr. Chandler was a founder, Chief Financial Officer and Senior Vice President for Rhythms Netconnections, Inc. (former NASDAQ: RTHM), a formerly publicly-traded corporation, where he served from 1998 to 2001. Mr. Chandler was a member of the senior management team that led this national provider of DSL networking and services prior to the sale of a majority of its assets to MCI Worldcom. From 1996 to 1998, Mr. Chandler served as President and Chief Executive Officer of C-COR Incorporated, or C-COR, a publicly-traded corporation and pioneer in the cable television industry and leading supplier of broadband telecommunications equipment. The common stock of C-COR was traded on the NASDAQ Global Market until the company was merged in late 2007. Prior to C-COR, Mr. Chandler held a number of positions at US WEST. Mr. Chandler's business career began with Arthur Andersen & Co. as a Senior Consultant/Accountant. He earned an M.B.A. from the Wharton School of Business at the University of Pennsylvania and a B.A. from Whitworth University. Mr. Chandler currently serves as a member of the board of directors of several privately-held and non-profit entities and has in the past served as a member of several public company boards, such as Cimetrix Incorporated (OTCMKTS: CMXX), Tollgrade Communications Inc. (NASDAQ: TLGD), and Paradyne Networks Inc. (NASDAQ: PDYN). He has been determined to be an audit committee financial expert under applicable rules of the Securities and Exchange Commission, or the SEC. Mr. Chandler's extensive audit and SEC reporting experience will give him valuable insight into our financial reporting and internal control and risk control procedures. For these reasons, we believe Mr. Chandler is qualified to serve as a director of our company.

James H. Sinclair, Director. Mr. Sinclair joined our Board of Directors in May 2016. Mr. Sinclair has over 31 years of experience in exploration, development, acquisitions and divestitures in the oil and gas industry. Since joining our board, Mr. Sinclair has served as a consultant to PEC E&P, LLC, which is the managing member of Providence, immediately prior to which he served as PEC's Chief Operating Officer, a position he held since April 2014. PEC invests primarily in non-operated oil and gas properties in the United States. In his role as a consultant to PEC, Mr. Sinclair assists with the identification, analysis, and recommendation of oil and gas investment opportunities. In 2010, Mr. Sinclair co-founded Petro Harvester O&G, LLC, an oil and gas production company, where he served as President and Chief Operating Officer until 2012. From 1993 until 2008, Mr. Sinclair served as the Exploration Manager, District Manager of Mississippi, Director of Acquisitions, and Vice President of Exploration and Geosciences of Denbury Resources Inc. (NYSE: DNR), a publicly traded exploration and production company with operations primarily in the Gulf Coast area and offshore Gulf of Mexico. Mr. Sinclair received a B.S. in Geoscience from Northeast Louisiana University. Mr. Sinclair has significant experience in the management and financing of oil and gas companies. For these reasons, we believe Mr. Sinclair is qualified to serve as a director of our company.

Douglas R. Harris, Director. Mr. Harris joined our Board of Directors in July 2016. Mr. Harris has over 38 years of experience in the oil and gas industry. In March 2015, he founded and currently serves as the Chief Operating Officer of Axia Energy II, LLC, a company that identifies and develops oil and gas prospects throughout the United States. From 2009 to 2015, Mr. Harris served as co-founder and Chief Operating Officer of Axia Energy I, LLC, also a company that identifies and develops oil and gas prospects throughout the United States. Prior to that, he served as the co-founder and Vice President of Operations for Orion Energy Partners, Inc., a position he held from 2004 to 2009, and the Vice President and General Manager of the Denver Division of Tom Brown Inc., a position he held from 2001 to 2004. From 1986 to 2001, Mr. Harris served in numerous positions for Burlington Resources Inc., culminating as the Vice President of Production Operations in its Calgary, Alberta offices. He serves on the board of directors of a number of privately-held companies. Mr. Harris holds a B.S. in Civil Engineering from New Mexico State University. For these reasons, we believe Mr. Harris is qualified to serve as a director of our company.

Code of Ethics

On March 1, 2016, our Board of Directors adopted a code of ethics, a copy of which is available on our website at www.petrosharecorp.com. We believe that the code of ethics is reasonably designed to deter wrongdoing and promote honest and ethical conduct; provide full, fair, accurate, timely and understandable disclosure in public reports; comply with applicable laws; ensure prompt internal reporting of code violations; and provide accountability for adherence to the code.

Director Independence

Our Board of Directors has determined that Bill M. Conrad, Scott C. Chandler, James H. Sinclair, and Douglas R. Harris each qualify as "independent" in accordance with Section 803(A) of the NYSE American Company Guide. During the review, our Board of Directors considered relationships and transactions during 2018 and during the past three fiscal years between each director or any member of his immediate family, on the one hand, and our company and our affiliates, on the other hand. The purpose of this review was to determine whether any such relationships or transactions were inconsistent with a determination that the director is independent. The only compensation or remuneration that we provide to Messrs. Conrad, Chandler, Sinclair, or Harris during their tenures as a director is compensation as a non-employee director. None of Messrs. Conrad, Chandler, Sinclair, or Harris, nor any members of their families, has participated in any transaction with us that would disqualify him as an "independent" director under the standard described above. Stephen J. Foley and Frederick J. Witsell do not qualify as "independent" because they are executive officers. Mr. Drysdale, Mr. Allen and Mr. Schaar do not qualify as "independent" because of their affiliation with Providence Energy Operators and or Providence Wattenberg LP.

Board Committees

Audit Committee. Messrs. Conrad, Chandler, and Harris serve as members of our audit committee and Mr. Chandler serves as the Chairman of the audit committee. The Board has determined that Messrs. Conrad, Chandler, and Harris are each "independent" in accordance with the NYSE American definition of independence, that Mr. Chandler is a "financial expert," as defined by SEC regulations, and each has the related financial management expertise within the meaning of the NYSE American rules.

The primary purpose of the audit committee is to act on behalf of our Board of Directors in its oversight of all material aspects of our accounting and financial reporting processes, internal controls, and audit function, including our compliance with Section 404 of the Sarbanes-Oxley Act of 2002. Pursuant to its charter, our audit committee reviews on an on-going basis for potential conflicts of interest, and approves if appropriate, all of our related party transactions. For purposes of the audit committee charter, related party transactions mean those transaction required to be disclosed pursuant to SEC regulations. In addition, the audit committee reviews, acts on, and reports to our Board of Directors with respect to various auditing and accounting matters, including the selection of our independent registered public accounting firm, the scope of annual audits, fees to be paid to our independent registered public accounting firm, the performance of our independent registered public accounting firm, our accounting practices, and our internal controls and legal compliance functions. The audit committee also reviews, prior to publication, our reports to the SEC on Forms 10-K and 10-Q. The audit committee operates pursuant to a written charter, which is available on our website, www.petrosharecorp.com. The charter describes the nature and scope of responsibilities of the audit committee.

The Audit Committee's policy is to pre-approve all audit and non-audit services provided by the independent registered public accounting firm. These services may include audit services, audit-related services, tax services and other services. The independent auditors are required to periodically report to the Audit Committee regarding the extent of services provided by the independent registered public accounting firm in accordance with such pre-approval.

Compensation Committee. We do not currently have a compensation committee. Under a policy adopted by our Board, the compensation of our Chief Executive Officer and all other executive officers will be determined by a majority of our independent directors. Executive officers who also serve on our Board of Directors do not vote on matters pertaining to their own personal compensation. Although we may form a compensation committee in the future, there is no assurance as to when or whether we will do so.

Nominating and Corporate Governance Committee. We do not currently have a nominating and corporate governance committee. Board of Directors nominations are selected by a majority of our independent directors.

Section 16(a) Beneficial Ownership Reporting Compliance

Since we do not have a class of securities registered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and have never registered a class of securities under the Exchange Act, none of our officers, directors or beneficial owners of our common stock are required to file reports under Section 16 of the Exchange Act.

ITEM 11. EXECUTIVE COMPENSATION

Compensation to Officers of the Company

Our "named executive officers" include our chief executive officer, our chief financial officer and the two most highly compensated executive officers during 2018 other than the CEO and CFO. The following table contains compensation data for our named executive officers for the fiscal years ended December 31, 2018 and 2017:

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus	Stock Awards (1)	Option Awards (2)	All Other Compensation	Total
Stephen J. Foley	2018	$ 156,000	$ 5,000	—	—	—	$ 161,000
Chief Executive Officer	2017	$ 156,000	$ 50,000	—	—	—	$ 206,000
Frederick J. Witsell	2018	$ 156,000	$ 5,000	—	—	—	$ 161,000
President	2017	$ 156,000	$ 50,000	—	—	—	$ 206,000
Paul D. Maniscalco	2018	$ 150,000	$ 25,000	$ 47,251	$ 130,059	—	$ 352,310
Chief Financial Officer	2017	$ 161,733	$ 25,000	$ 27,573	—	—	$ 214,306
William B. Lloyd	2018	$ 156,000	$ 5,000	$ 10,738	$ 57,209	—	$ 228,947
Chief Operating Officer	2017	$ 156,000	$ 50,000	—	—	—	$ 206,000

(1) Calculated in accordance with the Black-Scholes option pricing model. Please see Note 8 to the consolidated financial statements included in this report for a description of certain assumptions made in conjunction with the valuation of these awards.
(2) Calculated in accordance with the Black-Scholes option pricing model. Please see Note 8 to the consolidated financial statements included in this report for a description of certain assumptions made in conjunction with the valuation of these awards.

Effective March 1, 2016, we entered into an amended and restated employment agreement with each Stephen J. Foley and Fredrick J. Witsell. Pursuant to the amended and restated employment agreements, Messrs. Foley and Witsell are each compensated by us at the rate of $13,000 per month, or $156,000 per year. We entered into an executive employment agreement with William B. Lloyd, Chief Operating Officer, effective January 1, 2016 and amended on March 1, 2016 pursuant to which Mr. Lloyd is compensated at the rate of $13,000 per month, or $156,000 per year. For each of the foregoing executives, the employment agreements provide for an initial term expiring on December 31, 2018 with an automatic renewal for successive one-year periods unless terminated in accordance with its terms. The employment agreements with Messrs. Foley, Witsell and Lloyd provide for the payment of severance to the employee in the amount of 12 months of the executive's then-current base salary, payable monthly in accordance with our then-current payroll practice, unless such termination is within six months before or at any time following a change in control as defined in the agreements, in which case the payments must be paid in full within 60 days of the date of termination.

On June 1, 2017, we entered into an executive employment agreement with our Chief Financial Officer Paul D. Maniscalco. The agreement provides for a base salary of $150,000 per year, an initial term expiring on December 31, 2018 with an automatic renewal for successive one-year periods unless terminated in accordance with its terms. The employment agreement with Mr. Maniscalco provides for the payment of severance in a manner and for the same reasons as those for Messrs. Foley, Witsell and Lloyd described above, except that the severance for Mr. Maniscalco provide for four months of the executive's then-current base salary.

Grants of Plan Based Awards

The grants of plan-based awards under our Equity Incentive Plan to each named executive officer during the year ended December 31, 2018 are as follows:

Name	Grant Date (1)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stocks or	All Other Option Awards: Number of Securities Underlying	Exerciseor Base Price of Option Awards	Grant Date Fair Value Of Stock And Option Awards
		Threshold	Target	Maximum	Threshold	Target	Maximum	Units	Options	($/sh)	($) (2)
Paul D. Maniscalco	03/01/2018	—	—	—	—	—	—	—	100,000	$ 1.03	$ 63,286
Paul D. Maniscalco	11/28/2018	—	—	—	—	—	—	—	250,000	$ 0.63	$ 77,323
William B. Lloyd	07/24/2018	—	—	—	—	—	—	—	90,000	$ 1.30	$ 57,209
William B Lloyd	07/24/2018	—	—	—	—	—	—	45,000	—	$ 1.30	$ 58,500

(1) The options are subject to a vesting schedule which requires that the named executive remain an employee of or consultant to the Company in order to exercise such options on the respective vesting date. The target amounts shown in the table represent the maximum number that may be earned if the vesting schedule is satisfied.

(2) Calculated using the Black-Scholes option pricing model. Please see Note 8 to the consolidated financial statements filed with our annual report on Form 10-K for the year ended December 31, 2018 for a description of certain assumptions made in connection with the valuation of these option awards.

Outstanding Equity Awards at Year End

The following table sets forth outstanding stock option awards held by our named executive officers as of December 31, 2018:

Name	Option awards				
	Number of securities underlying unexercised options (#) exercisable	Number of securities underlying unexercised options (#) unexercisable	Number of securities underlying unexercised unearned options (#)	Option exercise price ($)	Option expiration date
Stephen J. Foley	500,000	—	—	0.25	12/15/2022
Frederick J. Witsell	1,000,000	—	—	0.25	12/15/2022
Paul D. Maniscalco	250,000	—	—	0.63	12/31/2022
Paul D. Maniscalco	100,000	—	—	1.03	03/01/2023
William B. Lloyd	90,000	—	—	1.30	12/31/2022
William B. Lloyd	875,000	—	—	1.00	12/31/2022

Director Compensation

Bill M. Conrad, the Chairman of our Board of Directors, is paid a director's fee in the amount of $10,000 per month. Scott C. Chandler, as the chair of the audit committee, is paid a director's fee in the amount of $9,000 per quarter. James H. Sinclair and Douglas R. Harris are each are paid a director's fee in the amount of $6,000 per quarter. Messrs. Foley and Witsell are not compensated in their capacities as directors. We do, however, reimburse all of our directors for reasonable and necessary expenses incurred by them in that capacity.

We will review our compensation arrangements periodically in the future and may change our compensation policies as our business needs dictate and our resources permit.

The following table sets forth with respect to the directors, compensation information inclusive of equity awards and payments made during the year ended December 31, 2018 in the director's capacity as such:

Name	Year	Stock Awards ($)	Option Awards ($)	All Other Compensation	Total

		Fees Earned or Paid in Cash ($)				
Bill M. Conrad	2018	120,000	—	—	5,000	125,000
Stephen J. Foley	2018	—	—	—	—	—
Frederick J. Witsell	2018	—	—	—	—	—
Scott C. Chandler	2018	36,000	—	—	—	36,000
Douglas R. Harris	2018	24,000	—	—	—	24,000
James H. Sinclair	2018	24,000	—	—	—	24,000
Joseph Drysdale	2018	12,000	—	—	—	12,000
Michael Allen	2018	12,000	—	—	—	12,000
Cullen Schaar	2018	12,000	—	—	—	12,000

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Beneficial Ownership

As of April 2, 2019, there were a total of 28,077,337 shares of our common stock outstanding, our only class of voting securities currently outstanding. The following table describes the ownership of our voting securities as of April 2, 2018 by: (i) each of our named executive officers and directors; (ii) all of our officers and directors as a group; and (iii) each shareholder known us to own beneficially more than 5% of our common stock. Unless otherwise stated, the address of each of the individuals is our address, 9635 Maroon Circle, Suite 400, Englewood, Colorado 80112.

In calculating the percentage ownership for each shareholder, we assumed that any options, warrants, or convertible promissory notes owned by an individual and exercisable or convertible within 60 days are exercised or converted, but not the options, warrants, or convertible promissory notes owned by any other individual.

Name and Address of Beneficial Owner	Number		Percentage (%)
Bill M. Conrad(1)	2,318,907	(2)	8.1
Stephen J. Foley(1)	2,301,307	(2)	8.0
Frederick J. Witsell(1)	3,883,485	(3)	13.3
Paul D. Maniscalco(1)	471,259	(4)	1.7
William B. Lloyd(1)	1,303,573	(5)	4.5
William R. Givan(1)	450,120	(6)	1.6
Jon B. Kruljac(1)	1,297,673	(7)	4.4
Scott C. Chandler(1)	228,394	(8)	*
James H. Sinclair(1)(9)	276,907	(10)	1.0
Douglas R. Harris(1)	243,573	(11)	*
Providence Energy Operators, LLC (12)16400 Dallas Parkway, Dallas, Texas 75248	3,250,000		11.6
Providence Wattenberg, LP (13)16400 Dallas Parkway, Dallas, Texas 75248	9,375,526	(14)	25.0
5NR Wattenberg, LLC (15)16400 Dallas Parkway, Dallas, Texas 75248	9,375,526	(14)	25.0
All officers and directors as a group (10 persons)	12,762,770	(16)	37.8

● Less than one percent.

(1) Officer or director of PetroShare.
(2) Includes (i) 500,000 shares of common stock underlying options which are currently exercisable, (ii) 66,666 shares underlying warrants that are currently exercisable and (iii) 66,667 shares of common stock which may be currently issued upon conversion of notes.
(3) Includes (i) 1,000,000 shares of common stock underlying options which are presently exercisable, (ii) 56,666 shares underlying warrants that are currently exercisable and (iii) 45,001 shares of common stock which may be currently issued upon conversion of notes.
(4) Includes (i) 250,000 shares of common stock underlying options which are presently exercisable, (ii) 100,000 shares underlying options that vest within 60 days, (iii) 33,333 shares underlying warrants that are currently exercisable, (iv) 26,667 shares of common stock which may be currently issued upon conversion of notes.
(5) Includes (i) 965,000 shares of common stock underlying options which are presently exercisable, (ii) 66,666 shares underlying warrants that are currently exercisable and (iii) 33,333 shares of common stock which may be currently issued upon conversion of notes.
(6) Includes (i) 250,000 shares of common stock underlying options which are presently exercisable, (ii) 100,000 underlying options that vest within 60 days, (iii) 33,333 shares underlying warrants that are currently exercisable and (iv) 20,000 shares of common stock which may be currently issued upon conversion of notes.
(7) Includes (i) 800,000 shares of common stock underlying options which are presently exercisable, (ii) 227,691 shares underlying warrants that are currently exercisable, and (iii) 66,667 shares which may be currently issued upon conversion of notes.
(8) Includes (i) 25,000 shares of common stock underlying options which are presently exercisable, (ii) 16,667 shares underlying warrants that are currently exercisable and (iii) 8,333 shares of common stock which may be currently issued upon conversion of notes.
(9) James H. Sinclair disclaims any beneficial ownership of shares of common stock owned by Providence Energy Operators, LLC, or Providence.

(10) Includes (i) 25,000 shares of common stock underlying options which are presently exercisable, (ii) 66,666 shares underlying warrants that are currently exercisable and (iii) 66,667 shares of common stock which may be currently issued upon conversion of notes.

(11) Includes (i) 25,000 shares of common stock underlying options which are presently exercisable, (ii) 66,666 shares underlying warrants that are currently exercisable and (iii) 33,333 shares of common stock which may be currently issued upon conversion of notes.
(12) PEC E&P, LLC, a Texas limited liability company whose address is 16400 Dallas Parkway, Dallas, Texas, 75248, (i) is the managing member of Providence, (ii) has voting and investment control of the securities owned by Providence, and (iii) should be considered a beneficial owner of the shares of common stock owned by Providence.
(13) Providence Wattenberg GP, LLC, a Texas limited liability company, whose address is 16400 Dallas Parkway, Dallas, Texas, 75248, (i) is the general partner of Providence Wattenberg, LP, (ii) has management and investment control of the securities owned by Providence Wattenberg, LP, and (iii) should be considered a beneficial owner of any securities owned or held by Providence Wattenberg, LP.
(14) Includes (i) 750,000 shares underlying warrants which are currently exercisable and (ii) 8,625,526 shares which may be currently issued upon conversion of outstanding notes.
(15) 5NR Wattenberg LLC is a Texas limited liability company with an address at 16400 Dallas Parkway, Dallas, Texas, 75248. Joseph Drysdale as the manager of the reporting person, exercises voting and investment control over these securities.
(16) Includes (i) 4,415,000 shares of common stock underlying options which are presently exercisable, (ii) 200,000 shares underlying options that vest within 60 days, (iii) 701,020 shares underlying warrants that are currently exercisable, and (iv) 433,335 shares of common stock which may be currently issued upon conversion of notes.

Changes in Control

If Providence Wattenberg, LP and 5NR Wattenberg, LLC, our Secured Lenders and the beneficial owners of more than 5% of our common stock, converted their debt in accordance with the provisions of the Secured Credit Facility, we may experience a change in control. That conversion would result in those two entities owning in the aggregate 40% of our outstanding common stock. At present, neither of those entities has expressed any intent to convert their debt.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The following includes a summary of transactions, during our last two fiscal years, to which we have been a party, in which the amount involved in the transaction exceeded $120,000 or one percent of the average of our total assets at fiscal year-end for the last two fiscal years, and in which any of our directors, executive officers or, to our knowledge, beneficial owners of more than 5% of our capital stock or any member of the immediate family of any of the foregoing persons had or will have a direct or indirect material interest, other than equity and other compensation, termination, change in control and other arrangements which are described under “Director Compensation” and “Executive Compensation.”

Providence Energy Operators, LLC

Initial Line of Credit

- At December 31, 2018 and 2017, the Initial Line of Credit from Providence Energy Operators, LLC (“PEO”), the beneficial owner of more than 5% of our common stock, was $0 and $5.0 million and had accrued interest in the amount of $0.0 million and $0.5 million, respectively at those dates.

- On September 23, 2017, we issued 250,000 shares of common stock valued at $1.55 to PEO in connection with the extension of that loan.

On February 1, 2018, in connection with the closing of our Secured Credit Facility, the Initial Line of Credit was paid in full.

PEO was paid interest of $0.6 million and $0.2 million for the years ended December 31, 2018 and 2017, respectively.

Secured Credit Facility

- On February 1, 2018, we closed on a $25.0 million Secured Credit Facility with Providence Wattenberg, LP and 5NR Wattenberg, LLC (“Secured Lenders”). Each of Providence and 5NR are affiliates of the beneficial owners of more than 5% of our outstanding stock and of the Lenders under a Letter Agreement entered into by us on December 21, 2017, under which we borrowed $5.0 million. The closing on February 1, 2018 fully incorporates the 2017 Letter Agreement and represents additional borrowings of $20.0 million. We paid the Secured Lenders $3.8 million and $nil in interest for the years ended December 31, 2018 and 2017, respectively. On April

2, 2019, the Secured Lenders delivered their formal Notice of Default under the terms of the Secured Credit Facility. The Notice declared that all amounts outstanding were immediately due and payable.

Operations

- On May 13, 2015, we entered into the participation agreement with PEO. Under the terms of the participation agreement, we assigned an undivided 50% to our right, title and interest in and to our then existing leases and Providence agreed to pay its pro rata share of lease acquisition expenses and the expenses necessary to maintain the leases in full force and effect. In addition, the participation agreement designated an area of mutual interest, or AMI, pursuant to which if either party acquires any lease in the AMI territory, then the non-acquiring party would have the right to acquire its proportionate 50% interest in and to such AMI leases. To date, PEO has exercised its option to participate in all of our acreage acquisitions. The payments made to us by Providence were based on the pro rata share of our acquisition costs, which in turn were determined by negotiations with independent third parties.

- During the year ended December 31, 2018, we billed PEO $22.7 million in connection with drilling activity on the leases in which PEO participates. This amount relates to amounts billed to PEO in connection with its participation in our operated Shook drilling program and PEO’s ownership interest in the vertical wells that we operate.

Convertible Notes

During December 2016 and January 2017, we completed a private placement of 200 units at an offering price of $50,000 per unit. Certain of the units were purchased by our directors and officers in the following amounts and on the following dates on the same terms and conditions as independent third parties:

Name of Beneficial Owner	Number of Unit Purchased	Issuance Date
Bill M. Conrad	2.0	December 30, 2016
Stephen J. Foley	2.0	December 30, 2016
Frederick J. Witsell	1.7	January 20, 2017
Paul D. Maniscalco	1.0	December 30, 2016
William B. Lloyd	2.0	December 30, 2016
William R. Givan	1.0	December 30, 2016
Jon B. Kruljac	2.2	January 20, 2017
Scott C. Chandler	0.5	January 20, 2017
Douglas R. Harris	2.0	December 30, 2016
James H. Sinclair	2.0	December 30, 2016

On October 16, 2017, all of the officers and directors listed above converted Series A Notes in the aggregate principal amount of $0.7 million and accrued interest of $20,670 into 691,516 shares of common stock at a conversion rate of $1.10 per share.

Series B Convertible Notes

In September and October 2017, we sold Series B Notes to the same officers and directors who collectively purchased $0.6 million in aggregate principal amount, on the same terms and conditions as the other purchasers, with the exception that we did not pay commissions on these sales.

Those same officers and directors received cash interest payments for interest of $0.1 million and $0.1 million related to Series A and Series B notes during the years ended December 31, 2018 and 2017.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit Fees and Services

For the fiscal years ended December 31, 2018 and 2017, professional services were performed by Eide Bailly LLP. The aggregate fees for the fiscal years ended December 31, 2018 and 2017 were as follows:

	2018	2017
Audit Fees	$ 198,108	$ 68,987
Audit-Related Fees	—	—
Tax Fees	9,787	4,500
All Other Fees	—	—
Total	$ 207,895	$ 73,397

The Audit Committee's policy is to pre-approve all audit and non-audit services provided by the independent registered public accounting firm. These services may include audit services, audit-related services, tax services and other services. The independent auditors are required to periodically report to the Audit Committee regarding the extent of services provided by the independent registered public accounting firm in accordance with such pre-approval.

During the year ended December 31, 2018, the Audit Committee approved, in advance, all audit and non-audit services to be provided by Eide Bailly LLP. The Audit Committee has determined that the non-audit services rendered by Eide Bailly LLP during fiscal years 2018 and 2017 were compatible with maintaining the independence of the respective independent registered public accounting firms.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENTS SCHEDULES

(a)(1) Consolidated Financial Statements:

See Item 8 of this report for a list of consolidated financial statements filed with this report.

(a)(3) Exhibits required by Item 601 of Regulation S-K

The following exhibits are filed or incorporated by reference in this report:

EXHIBIT INDEX

.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Herewith
3.1	Articles of Incorporation as filed with the Colorado Secretary of State on September 4, 2012	S-1	333198881	3.1	September 22, 2014	
3.2	Articles of Amendment to Articles of Incorporation as filed with the Colorado Secretary of State on October 10, 2017					X
3.3	Articles of Amendment to Articles of Incorporation as filed with the Colorado Secretary of State on March 20, 2019					X
3.4	Bylaws of the Company dated November 30, 2012	S-1	333198881	3.2	September 22, 2014	
4.1	Specimen stock certificate	S-1	333198881	4.1	November 5, 2014	
4.2	Form of Representatives Warrant Agreement	S-1	333198881	4.2	August 27, 2015	
4.3	Form of Warrant to purchase common stock	8-K	00137943	4.1	February 3, 2017	
4.4	Form of Placement Agent Warrant	8-K	00137943	4.2	February 3, 2017	
10.1	Amended and Restated PetroShare Corp. Equity Incentive Plan dated August 18, 2016	8-K	333198881	10.1	September 13, 2016	
10.2	Form of Option Agreement	S-1	333198881	10.2	September 22, 2014	
10.3	Form of Amended and Restated Employment Agreement	8-K	333198881	10.2	March 1, 2016	
10.4	Amended and Restated Executive Employment Agreement between the Company and Stephen J. Foley, effective March 1, 2016	S-1	333-218096	10.4	May 19, 2017	
10.5	Amended and Restated Executive Employment Agreement between the Company and Frederick J. Witsell, effective March 1, 2016	S-1	333-218096	10.5	May 19, 2017	
10.6	Executive Employment Agreement between the Company and Paul D. Maniscalco effective June 1, 2017	8-K	001-37943	10.1	June 2, 2017	
10.7	Executive Employment Agreement between the Company and William B. Lloyd, effective January 1, 2016	8-K	333198881	10.3	March 1, 2016	
10.8	Form of Joint Operating Agreement	S-1	333198881	10.9	September 22, 2014	

10.12	Participation Agreement dated May 13, 2015	10-Q	333198881	10.4	May 15, 2015
10.23	Form of Restricted Stock Agreement	S-1	333-218096	10.26	May 19, 2017
10.26	Form of 10% Convertible Promissory Note	8-K	001-37943	10.1	February 2, 2017
10.27	Form of Series B Unsecured Convertible Promissory Note	10-Q	001-37943	10.3	November 14, 2017
10.28	Placement Agent Agreement between the Company and GVC Capital LLC dated September 11, 2017	10-Q	001-37943	10.4	November 14, 2017

10.30	Secured Term Credit Agreement among the Company, Providence Wattenberg, LP and 5NR Wattenberg, LLC, dated February 1, 2018	8-K	001-37943	10.1	February 7, 2018	
10.31	Form of Deed of Trust, Mortgage, Assignment of Production, Security Agreement and Financing Statement	8-K	001-37943	10.2	February 7, 2018	
10.32	First Amendment to Amended and Restated Participation Agreement, dated February 1, 2018	8-K	001-37943	10.3	February 7, 2018	
10.33	Registration Rights Agreement between the Company, Providence Wattenberg, LP, 5NR Wattenberg, LLC and Providence Energy Operators, LLC dated February 1, 2018	8-K	001-37943	10.4	February 7, 2018	
10.34	Purchase and Sale Agreement Between PetroShare Corp and Grizzley Petroleum Company, LLC dated January 15, 2019					X
14.1	Code of Ethics, dated March 1, 2016	8-K	333198881	14.1	March 1, 2016	
23.1	Consent of Independent Petroleum Engineer					X
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002					X
32.1	Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer					X
99.1	Report of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers relating to Proved Reserves, March 4, 2019					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Schema Document					X
101.CAL	XBRL Calculation Linkbase Document					X
101.DEF	XBRL Definition Linkbase Document					X
101.LAB	XBRL Label Linkbase Document					X
101.PRE	XBRL Presentation Linkbase Document					X

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PETROSHARE CORP.

By: /s/ STEPHEN J. FOLEY
Stephen J. Foley, *Chief Executive Officer*

Date: April 3, 2019

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated.

/s/ STEPHEN J. FOLEY Stephen J. Foley	Director and Chief Executive Officer (Principal Executive Officer)	April 3, 2019
/s/ PAUL D. MANISCALCO Paul D. Maniscalco	Chief Financial Officer (Principal Financial and Principal Accounting Officer)	April 3, 2019
/s/ BILL M. CONRAD Bill M. Conrad	Chairman of the Board of Directors	April 3, 2019
/s/ FREDERICK J. WITSELL Frederick J. Witsell	Director and President	April 3, 2019
/s/ SCOTT C. CHANDLER Scott C. Chandler	Director	April 3, 2019
/s/ DOUGLAS R. HARRIS Douglas R. Harris	Director	April 3, 2019
/s/ JAMES H. SINCLAIR James H. Sinclair	Director	April 3, 2019

Supplemental Information to be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

The registrant sent a proxy statement to its shareholders in connection with a special meeting of its shareholders held on March 15, 2019. A copy of the proxy statement was filed with the Commission under cover of Form 8-K on February 12, 2019.