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, 2017

☐ **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 001-33614

ULTRA PETROLEUM CORP.

(Exact name of registrant as specified in its charter)

Yukon, Canada	**N/A**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. employer identification number)*
400 North Sam Houston Parkway East, Suite 1200, Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip code)*

(281) 876-0120

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Shares, without par value	NASDAQ

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ☑ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in 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, or a smaller reporting 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. (Check one):

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 ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was $2,130,019,725 as of June 30, 2017 (based on the last reported sales price of $10.85 of such stock on the New York Stock Exchange on such date).

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13, or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. YES ☑ NO ☐

The number of common shares, without par value, of Ultra Petroleum Corp., outstanding as of February 15, 2018 was 196,346,736.

Documents incorporated by reference: The definitive Proxy Statement for the 2018 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2017 is incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

Certain Definitions

Terms used to describe quantities of oil and natural gas and marketing

- ***Bbl*** — One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.
- ***Bcf*** — One billion cubic feet of natural gas.
- ***Bcfe*** — One billion cubic feet of natural gas equivalent.
- ***Tcfe*** — One trillion cubic feet of natural gas equivalent.
- ***BOE*** — One barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.
- ***BTU*** — British Thermal Unit.
- ***Condensate*** — An oil-like, liquid hydrocarbon which is produced in association with natural gas production that condenses from natural gas as it is produced and delivered into a separator or similar equipment prior to the delivery of such natural gas to the natural gas gathering pipeline system.
- ***MBbl*** — One thousand barrels of crude oil or other liquid hydrocarbons.
- ***Mcf*** — One thousand cubic feet of natural gas.
- ***Mcfe*** — One thousand cubic feet of natural gas equivalent, converting oil, condensate or NGLs to natural gas at the ratio of one barrel of oil, condensate or NGLs to six Mcf of natural gas.
- ***MMBbl*** — One million barrels of crude oil or other liquid hydrocarbons.
- ***MMcf*** — One million cubic feet of natural gas.
- ***MMBTU*** — One million British Thermal Units.
- ***NGL or NGLs*** — Natural gas liquids, which are expressed in barrels.

Terms used to describe the Company's interests in wells and acreage

- ***Gross oil and natural gas wells or acres*** — The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
- ***Net oil and natural gas wells or acres*** — Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.
- ***Prospect*** — A location where hydrocarbons such as oil and gas are believed to be present in quantities which are economically feasible to produce.

Terms used to assign a present value to the Company's reserves

- ***Standardized measure of discounted future net cash flows, after income taxes*** — The present value, discounted at 10%, of the after tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and natural gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the oil and natural gas spot prices based on the average price during the 12-month period before the ending date of the period covered by the report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, adjusted for quality and transportation. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes, using rates in effect on the date of the report, are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.
- ***Standardized measure of discounted future net cash flows before income taxes*** — The discounted present value of proved reserves is identical to the standardized measure described above, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a better basis for comparison of its reserves to the producers who may have different income tax rates.

Terms used to classify the Company's reserve quantities

The Securities and Exchange Commission ("SEC") definition of proved oil and natural gas reserves, per Regulation S-X, is as follows:

Economically producible — A resource that generates revenue that exceeds (or is reasonably expected to exceed) costs of the operation.

Estimated ultimate recovery — The sum of reserves remaining as of a given date and cumulative production as of that date.

Proved oil and gas reserves — Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of available 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 regulation — before 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.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited fluid contacts, if any,

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period before the ending date of the period covered by the report, determined as an un-weighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved developed oil and gas reserves — Proved oil and gas reserves that can be expected to be recovered:

a. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

b. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves — Proved oil and 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 recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Reasonable certainty — If deterministic methods are used, a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable technology — A grouping of one or more technologies (including computational methods) that has been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves — Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Resources — Quantities of oil and 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.

Terms used to describe the legal ownership of the Company's oil and natural gas properties

- ***Revenue interest*** — The amount of the interest owned in the proceeds derived from a producing well less all royalty interests.
- ***Working interest*** — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Terms used to describe seismic operations

- ***Seismic data*** — Oil and natural gas companies use seismic data as their principal source of information to locate oil and natural gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- ***2-D seismic data*** — 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
- ***3-D seismic data*** — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three-dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Other Terms

- ***All-in costs*** — For any period, means the sum of lease operating expenses, liquids gathering system operating lease expense, severance taxes, gathering costs, transportation charges, depletion, depreciation and amortization, interest expense and general and administrative expenses divided by production on an Mcfe basis during the period.
- ***Reserve replacement ratio*** — The sum of the estimated net proved reserves added through extensions, discoveries, revisions and additions (including purchases of reserves) for a specified period of time divided by production for that same period of time.
- ***Finding and development costs*** — The sum of property acquisition costs, exploration costs and development costs for a specified period of time, divided by the total of proved reserve extensions, discoveries, revisions and additions (including purchases) for that same period of time.

PART I

Item 1.*Business.*

General

Ultra Petroleum Corp. ("Ultra" or the "Company") is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company was incorporated on November 14, 1979, under the laws of the Province of British Columbia, Canada. Ultra remains a Canadian company, but since March 2000, has operated under the laws of Yukon, Canada pursuant to Section 190 of the *Yukon Business Corporations Act*. The Company's principal business activities are developing its long-life natural gas reserves in the Green River Basin of southwest Wyoming — the Pinedale and Jonah fields and its oil reserves in the Uinta Basin in northeast Utah.

The Company's annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge to the public on the Company's website at www.ultrapetroleum.com. To access the Company's SEC filings, select "SEC Filings" under the Investors tab on the Company's website. You may also request a copy of these filings at no cost by making written or telephone requests for copies to Ultra Petroleum Corp., Director, Investor Relations, 400 N. Sam Houston Pkwy. E., Suite 1200, Houston, TX 77060, (281) 876-0120. Any materials that the Company has filed with the SEC may be read and/or copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding the Company. The SEC's website address is www.sec.gov.

Chapter 11 Proceedings

Voluntary Reorganization Under Chapter 11

On April 29, 2016 (the "Petition Date"), the Company and its subsidiaries (collectively, "the Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). Our chapter 11 cases were jointly administered under the caption *In re Ultra Petroleum Corp.,* et al, (Case No. 16-32202 (MI). On March 14, 2017, the Bankruptcy Court confirmed our *Debtors' Second Amended Joint Chapter 11 Plan of Reorganization* (the "Plan"), and on April 12, 2017 (the "Effective Date"), we emerged from bankruptcy. For further description of these matters, see Note 1 in this Form 10-K in our Consolidated Financial Statements.

Oil and Gas Properties Overview —

Principal Operating Areas

Ultra's operations in southwest Wyoming have historically focused on developing its long-life natural gas reserves in a tight gas sand trend located in the Green River Basin. The Company targets sands of the upper Cretaceous Lance Pool in the Pinedale and Jonah fields. The Lance Pool, as administered by the Wyoming Oil and Gas Conservation Commission ("WOGCC"), includes sands of the Lance formation at depths between approximately 8,000 and 12,000 feet and the Mesaverde formation at depths between approximately 12,000 and 14,000 feet. As of December 31, 2017, Ultra owned interests in approximately 112,000 gross (77,000 net) acres in Wyoming covering approximately 190 square miles.

The Company's operations in the Uinta Basin in Utah have focused on developing its oil-producing properties and undeveloped acreage covering approximately 8,000 net acres. The primary geologic target is the Eocene aged Green River formation found between subsurface depths of approximately 4,000 and 7,500 feet.

The Company had operations in north-central Pennsylvania with a focus on developing its natural gas reserves in the Marcellus Shale. During the fourth quarter of 2017, the Company divested certain non-core properties in the Pennsylvania Devonian aged Marcellus Shale (the "Pennsylvania Asset Sale"), which consisted of net production of approximately 30 million cubic feet per day, for net cash proceeds of approximately $115.0 million, subject to post-close purchase adjustments.

Mission and Strategy

Ultra's mission is to profitably grow an upstream oil and gas company for the long-term benefit of its shareholders. Ultra's strategy to achieve this goal includes building a portfolio of high return investment opportunities, maintaining a disciplined approach to capital investment, maximizing earnings and cash flows by controlling costs, utilizing advancements in drilling technologies to maximize results, and maintaining financial flexibility.

High Return Portfolio. Ultra seeks to maintain a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. The Company continually evaluates opportunities for the acquisition, exploration, and development of additional oil and natural gas properties that afford risk-adjusted returns in excess of or equal to its current set of investment alternatives.

Disciplined Capital Investment. The Company's business strategy includes proactive and regular review of its portfolio of investment opportunities with a focus on investments that produce positive returns in order to optimize return to its shareholders. The Company seeks to develop the resource from existing, self-funding assets over the next twenty years, while spending within cash flows in order to maximize profitability.

Focus on Maximizing Value. Ultra strives to maintain one of the lowest cost structures in the industry in terms of both adding and producing oil and natural gas reserves. The Company continues to focus on improving its drilling and production results using advanced technologies and detailed technical analysis of its properties, while maintaining its low cost structure, adhering to industry best practices, maintaining strict safety and environmental standards, and recruiting and retaining top talent within the Company.

Financial Strength and Flexibility. Preserving financial flexibility and a strong balance sheet are also key components of Ultra's business philosophy. At December 31, 2017, the Company had cash on hand of $16.6 million and outstanding debt of $2.2 billion. At December 31, 2017, the Company had $425.0 million of available borrowing under its revolving credit facility. The Company's average debt maturity is 5.8 years and the Company's weighted average cost of debt is approximately 6%. Further, the Company seeks to improve its cash flow visibility by hedging up to 50% of its forecasted volumes on an annual basis in order to manage commodity price risks and provide cash flow predictability.

Exploration and Production

Green River Basin, Wyoming

During 2017, the Company participated in the drilling of 210 wells in Wyoming and continued to improve its drilling and completion efficiency on its operated wells. The Company's operated vertical well costs declined from an annual average of $3.8 million per well during 2014 to $3.0 million per well average during 2017. The reduction in costs is attributable to drilling efficiencies and service cost reductions. The Company operates 89% of its production in the Pinedale field.

During 2018, the Company plans, based on the availability of capital, to continue developing its position in the Pinedale field, and will continue to target tight gas sands of the Lance Pool. All of the Company's drilling activity is conducted utilizing its extensive geological and geophysical data set. This data set is used to map the productive intervals, to refine areas of drilling focus, to identify areas for future extension of the Lance fairway with horizontal wells and to identify deeper objectives that may warrant drilling.

Utah

During 2017, the Company did not drill any wells on the Uinta Basin properties. The Company continued to expand its waterflood program resulting in incremental recovery in the first two pilot projects. At December 31, 2017, the company had 9 wells drilled but not completed in inventory. Ultra is the sole operator of the properties with a 100% working interest. At the end of 2017, approximately 88% of the Company's gross acreage holdings in Utah were held by production.

During 2018, the Company will consider strategic alternatives in Utah, including the possible divestiture of its assets.

Pennsylvania

During 2017, the Company did not drill any wells on its Pennsylvania properties and sold the properties during the quarter ended December 31, 2017.

Marketing and Pricing

Overview

During the year ended December 31, 2017, Ultra derived its revenues from the sale of its natural gas and associated condensate produced from wells operated by the Company in the Green River Basin in southwest Wyoming, from the sale of natural gas produced from wells operated by others in the Appalachian Basin in Pennsylvania, and from the sale of crude oil and natural gas from wells operated by the Company in the Uinta Basin of Utah. During the quarter ended December 31, 2017, the Company divested its natural gas reserves in the north-central Pennsylvania area of the Appalachian Basin. During 2017, 94% of the Company's production and 84% of its revenues were attributable to natural gas, with the balance attributable to associated condensate and crude oil.

The Company's natural gas revenues are determined by prevailing natural gas market prices in the Rocky Mountain region of the United States, specifically, southwest Wyoming, and prior to the Pennsylvania Asset Sale, were also determined by natural gas market prices in the Eastern region of the United States. The Company's oil revenues are determined by prevailing oil and condensate prices in the Rocky Mountain region of the United States.

Natural Gas Marketing

Ultra currently sells all of its natural gas production to a diverse group of third-party, non-affiliated entities in a portfolio of transactions of various durations and prices (daily, monthly and longer term). The Company's customer base includes a significant number of customers situated in the various regions of the United States. The sale of the Company's natural gas is "as produced". As such, the Company does not maintain any significant inventories or imbalances of natural gas.

Midstream services. For its natural gas production in Wyoming, the Company has entered into various gathering and processing agreements with several midstream service providers that gather, compress and process natural gas owned or controlled by the Company from its producing wells in the Pinedale Anticline and Jonah fields. Under these agreements, the midstream service providers continue to expand their facilities' capacities in southwest Wyoming to accommodate growing volumes from wells in which the Company owns an interest. The Company believes that the capacity of the midstream infrastructure related to its production will continue to be adequate to allow it to sell essentially all of its available natural gas production.

Basis differentials. The market price for natural gas is influenced by a number of regional and national factors which are beyond the Company's ability to control. These factors include, among others, weather, natural gas supplies, imports from Canada, natural gas demand, inventory levels in natural gas storage fields, and natural gas pipeline capacity to export gas from the basins where the Company's production is located. See Item 1A — Risk Factors for more information about risks to our financial condition and business results associated with basis differentials.

The Rocky Mountain region is a net exporter of natural gas because local natural gas production exceeds local demand, especially during non-winter months. As a result, natural gas production in southwest Wyoming has from time to time sold at a discount relative to other U.S. natural gas production sources or market areas. These regional pricing differentials, or discounts, are typically referred to as "basis" or "basis differentials" and are reflective, to some extent, of i.) the costs associated with transporting the Company's gas to markets in other regions or states, and ii.) the availability of pipeline capacity to move the Company's gas to market.

The Inside FERC First of Month Index for Northwest Pipeline — Rocky Mountains ("NwRox") is the price that is reflective of the Company's gas sold in the Opal, Wyoming area and the Inside FERC First of Month Index for Dominion Transmission Inc. — Appalachia is the price that was reflective of the Company's gas sold in Pennsylvania.

From 1990 to 2009, the average annual basis for NwRox averaged 23.7% below Henry Hub. After the Rockies Express and Ruby pipelines began flowing, the average annual basis for NwRox averaged 5.6% below Henry Hub from 2012 through 2016. The additional capacity of these two pipelines has had a significant positive impact on the value that the Company receives for its natural gas production in southwest Wyoming. In recent months, however, NwRox basis has weakened from levels realized in 2012 through 2016 mainly due to weakening fundamentals in the Company's core delivery area, California, and increasing flows from regions that produce significant quantities of oil and are connected by gas pipelines to the California market. In 2017, NwRox basis averaged an 11.9% discount to Henry Hub.

The table below provides a historical perspective on average annual basis differentials for Wyoming natural gas (NwRox) and Northeast (Appalachia). The basis differential is expressed as a percentage of the Henry Hub price as reported by Platt's M2M (Mark to Market) Report and Bloomberg on December 31, 2017.

	2014	2015	2016	2017
NW Pipeline Corp. — Rocky Mountains	96%	93%	91%	88%
Dominion Transmission Inc — Appalachia	74%	54%	56%	72%

Oil Marketing

Wyoming. The Company markets its Wyoming condensate to various purchasers, which are primarily refiners in the Salt Lake City, Utah area. The Company's condensate realized pricing is typically based on New York Mercantile Exchange crude futures daily settlement prices, less a negotiated location/transportation discount or differential. All of the Company's condensate sales are denominated in U.S. dollars per barrel and are paid for on a monthly basis. The Company routinely maintains only operating inventories of condensate production and sells its product on an "as produced" basis. A portion of the Company's condensate sales are entered into by its operating partners in the Pinedale field.

Utah. The Company's properties in the Uinta Basin produce what is typically referred to as Black Wax Crude which is considered a medium grade of crude oil. This oil is marketed through short-term or long-term contracts with refiners in the Salt Lake City, Utah area. The price for the Company's crude oil production is typically based off of NYMEX pricing for West Texas Intermediate Crude Oil or from a posting for Black Wax Crude in the Uinta Basin, less a negotiated location/transportation discount or differential.

Derivatives

The Company, from time to time and in the regular course of its business, enters into hedges for volumes equivalent to a portion of expected future production volumes, primarily through the use of financial swaps with creditworthy financial counterparties (See Note 12), or through the use of fixed price, forward sales of physical product. The Company plans to enter into additional hedge positions in much the same manner as it has done previously. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The Company's hedging policy limits the volumes hedged to not more than 50% of its forecasted production without Board approval. During 2017 and 2015, the quantities that the Company hedged for the twelve-month period represented 40% and 62%, respectively, of the Company's forecasted production for such periods. During 2016, the Company did not have any open hedge positions. Where the Company hedged more than 50% of its forecasted production, Ultra's board approved hedges of greater than 50% of the Company's forecasted production for each respective period. (See Note 7 for additional information).

Significant Counterparties

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2017, the Company had no single counterparty that represented 10% or more of the Company's total revenues.

The Company maintains credit policies intended to mitigate the risk of uncollectible accounts receivable related to the sale of natural gas and condensate as well as commodity derivatives. A more complete description of the Company's credit policies is described in Note 12. The Company did not have any outstanding, uncollectible accounts for its natural gas and oil sales at December 31, 2017.

Regulatory Matters

The Company's oil and gas operations are subject to a number of regulations. Governing agencies may include one or more of the following levels: Federal, Regional, State, County, Municipality, Tribal or other public entities. In general, the purposes of these regulations are to prevent waste of oil and natural gas resources, protect the rights of surface and mineral owners, regulate interstate transportation of oil and gas, and to govern environmental quality. Common forms of regulations may include:

- Notification to stakeholders of proposed and ongoing operations;
- Nondiscrimination statutes;
- Royalty and related valuation requirements;
- On-site security and bonding requirements;
- Location and density of drilling;
- Method of drilling, completing and operating wells;
- Measurement and reporting of oil and gas;
- Rates, terms and conditions applicable to the interstate transportation of oil and gas;
- Production, severance and ad valorem taxes;
- Management of produced water and waste; and
- Surface use, reclamation and plugging and abandonment of wells.

A significant portion of the Company's operations are located on federal lands in the Pinedale and Jonah Fields of Sublette County, Wyoming. The development activities in these fields are subject to the regulation of the U.S. Bureau of Land Management ("BLM") which is responsible for governing their surface and mineral rights and regulating certain development activities in these fields. As required under the National Environmental Policy Act ("NEPA"), an Environmental Impact Statement ("EIS") was prepared to quantify and address potential impacts of natural gas development in both the Pinedale and Jonah fields. In March 2006, the BLM issued its Record of Decision ("ROD") which provides broad authorization for the development activities currently occurring in the Jonah Area. In September 2008, the BLM issued its ROD that currently governs the development activities in the Pinedale Area. In addition to the overarching authorizations provided by the Jonah and Pinedale RODs, BLM issues site-specific authorizations such as rights of way and permits to drill on an ongoing basis.

The Pinedale ROD includes some significant components to ensure the orderly and responsible development of natural gas concurrent to minimizing the environmental impact. Some of these components include:

- Year-round operations on multi-wells pads;
- Liquid gathering systems to reduce truck traffic and minimize impacts to air quality and wildlife;
- Monitoring of key wildlife species and mitigation of monitored impacts;
- Advanced emission reductions including best practices such as controlled drill rigs;
- Spatial progression of development to address specific surface and wildlife issues;

- Annual meeting and long-range planning requirements to allow for socioeconomic predictability;
- Adaptive Management to consider current and changing conditions and facilitate common-sense solutions; and
- Suspension of flank acreage until core acreage is developed and returned to a functioning habitat.

While the majority of the Company's operations in Wyoming are covered by the Pinedale ROD, provisions of the Jonah ROD similarly ensure responsible and orderly development of the Jonah field while minimizing the environmental impact:

- Annual reporting and long-range planning requirements to allow for planned mitigation and socioeconomic predictability;
- Emission reduction report to ensure air quality goals are met;
- Annual water well monitoring reports; and
- Flareless-completion technology to reduce noise, visual impacts and air emissions.

The State of Wyoming maintains governance over some of the more traditional state-regulated matters such as individual well drilling permits, spacing and pooling, wellbore construction, as well as its own regulations on safety and environmental matters. The Wyoming Oil and Gas Conservation Commission ("WOGCC") has authorized drilling density up to 1 well per 5 acres in the Pinedale field and up to 1 well per 10 acres in the Jonah field.

Regulations are well documented and the Company believes that it is substantially in compliance with current applicable laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company. However, changes to certain existing regulations are beyond the control of the Company and could introduce uncertainty and additional costs. Please see Section 1A: Risk Factors for additional information.

Mineral Leasing Act

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits ownership of any direct or indirect interest in federal onshore oil and gas leases by a foreign citizen or a foreign corporation except through stock ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or corporations of the United States. If these restrictions are violated, the oil and gas lease can be canceled in a proceeding instituted by the United States Attorney General. The Company qualifies as a corporation formed under the laws of the United States or of any U.S. State or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns interests in numerous federal onshore oil and gas leases. It is possible that holders of the Company's equity interests may be citizens of foreign countries that are determined to be non-reciprocal countries under the Mineral Act. In such event, the federal onshore oil and gas leases held by the Company could be subject to cancellation based on such determination.

Environmental and Occupational Safety and Health Matters

Surface Damage Acts

Several states, including Wyoming, and some tribal nations have enacted surface damage statutes. These laws are designed to compensate for damages caused by oil and gas development operations. Most surface damage statutes contain entry and negotiation requirements to facilitate contact between the operator and surface owners. Most also contain binding requirements for payments by the operator in connection with development operations. Costs and delays associated with surface damage statutes could impair operational effectiveness and increase development costs.

Environmental Regulations

General. The Company's exploration, drilling and production activities from wells and oil and natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil, natural gas and other products are subject to numerous stringent federal, state and local laws and regulations relating to environmental quality, including those relating to oil spills and pollution control. These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. The U.S. Environmental Protection Agency ("EPA") has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2017-2019 and as a general matter, the oil and gas exploration and production industry has been and continues to be the subject of increasing scrutiny and regulation by environmental authorities.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot be sure that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. However, it is anticipated that, absent the occurrence of an extraordinary event, compliance with these laws and regulations will not have a material effect upon the Company's operations, capital expenditures, earnings or competitive position.

Solid and Hazardous Waste. The Company has previously owned or leased and currently owns or leases, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although the Company utilized standard operating and disposal practices, hydrocarbons or other solid wastes may have been disposed of or released on or under such properties or on or under locations where such wastes have been taken for disposal. In addition, many of these properties are or have been operated by third parties over whom the Company has no control, nor has ever had control as to such entities' treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and natural gas wastes and properties have gradually become stricter over time. Under current and evolving law, it is possible the Company could be required to remediate property, including ground water, impacted by operations of the Company or by such third-party operators, or impacted by previously disposed wastes including performing remedial plugging operations to prevent future, or mitigate existing contamination.

Although oil and gas wastes generally are exempt from regulation as hazardous wastes ("Hazardous Wastes") under the federal Resource Conservation and Recovery Act ("RCRA") and some comparable state statutes, it is possible some wastes the Company generates presently are or in the future may be subject to regulation under RCRA and state analogs, even as non-hazardous wastes. The EPA and various state agencies have limited the disposal options for certain wastes, including Hazardous Wastes and there is no guarantee that the EPA or the states will not adopt more stringent requirements in the future. For example, in May 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Columbia that sought to compel the EPA to review and, if necessary, revise its regulations regarding existing exemptions for exploration and production related wastes. Pursuant to a consent decree entered December 28, 2016 that settled the lawsuit, the EPA committed to propose by March 15, 2019 new regulations for the management of oil and gas wastes under RCRA Subtitle D (which relates to non-hazardous wastes), or sign a determination that a revision of existing rules is unnecessary. If the EPA proposes new rulemaking, the Consent Decree requires the EPA to take final action on such rules no later than July 15, 2021. Furthermore, certain wastes generated by the Company's oil and natural gas operations that are currently exempt from designation as Hazardous Wastes may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly operating and disposal requirements.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials ("NORM") may affect our operations. For example, the Pennsylvania Department of Environmental Protection has asked operators to identify technologically enhanced NORM ("TENORM") in their processes, such as hydraulic fracturing sand. Local landfills only accept such waste when it meets their TENORM permit standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste, potentially increasing our disposal costs.

Hydraulic Fracturing. Many of the Company's exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. Hydraulic fracturing activities are typically regulated by state oil and gas commissions. The EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the federal Safe Drinking Water Act ("SDWA") involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Congress has periodically considered legislation to amend the SDWA to remove the exemption from permitting and regulation provided to injection for hydraulic fracturing (except where diesel is a component of the fracturing fluid) and to require the disclosure and reporting of the chemicals used in hydraulic fracturing. This type of federal legislation, if adopted, could lead to additional regulation and permitting requirements that could result in operational delays making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and operating costs.

In addition, the EPA has issued guidance regarding federal regulatory authority over hydraulic fracturing using diesel under the Safe Drinking Water Act's Underground Injection Control Program. Further, in December 2016 the EPA released its final report on a wide-ranging study on the effects of hydraulic fracturing resources. While no widespread impacts from hydraulic fracturing were found, the EPA identified a number of activities and factors that may have increased risk for future impacts. Furthermore, a number of public and private studies are underway regarding the connection, if any, between the disposal of waste water associated with hydraulic fracturing and observed seismicity in the vicinity of such disposal operations. These studies and the EPA's enforcement initiative for the energy extraction sector could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In addition, some states, including Wyoming, Utah, and Colorado, have adopted, and other states are considering adopting, regulations that require disclosure of the chemicals in the fluids used in hydraulic fracturing or well stimulation operations. Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some case impose a moratorium on hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding permitting, casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. For example, the Pennsylvania Supreme Court has limited the state's ability to limit such ordinances at and strengthened the ability of municipalities to enact local ordinances regulating drilling activities. Although none of the Company's properties are in jurisdictions where the moratoria have been imposed, it is possible the jurisdictions where the Company's properties are located may adopt such limits or other limits on hydraulic fracturing in the future. The BLM finalized regulations for hydraulic fracturing activities on federal lands in March 2015, though a preliminary injunction was issued in June 2015 prior to implementation. In June 2016, a U.S. District Court judge ruled that the BLM has no authority to regulate hydraulic fracturing. Under a new administration, in December 2017, BLM subsequently rescinded the hydraulic fracturing regulations at issue. Further, the EPA has announced an initiative under the Toxic Substances Cont rol Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals and is working on regulations for wastewater generated by hydraulic fracturing.

Superfund. Under the federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, liability, generally, is joint and several for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRP"), include current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance, persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility, and in some cases the parties transporting such Hazardous Substances to the facility at issue. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to releases and threats of releases to protect the public health or the environment and to seek to recover from the PRP the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, adulterated petroleum products containing other Hazardous Substances have been treated as Hazardous Substances in the past, and the Company has generated and will generate wastes that fall within CERCLA's definition of Hazardous Substances. The Company may also be an owner or operator of facilities on which Hazardous Substances have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages, as a past or present owner or operator or as an arranger. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes was not under our control. Many states have comparable laws imposing liability on similar classes of persons for releases, including for releases of materials that may not be included in CERCLA's definition of Hazardous Substances. To its knowledge, the Company has not been named a PRP under CERCLA (or any comparable state law) nor have any prior owners or operators of its properties been named as PRPs related to their ownership or operation of such property.

National Environmental Policy Act. The federal National Environmental Policy Act provides that, for federal actions significantly affecting the quality of the human environment, the federal agency taking such action must prepare an Environmental Assessment ("EA") or an environmental impact statement (EIS). In the EIS, the agency is required to evaluate alternatives to the proposed action and the environmental impacts of the proposed action and of such alternatives. Actions of the Company, such as drilling on federal lands, to the extent the drilling requires federal approval, may trigger the requirements of the National Environmental Policy Act, including the requirement that an EA or EIS be prepared. The requirements of the National Environmental Policy Act may result in increased costs, significant delays and the imposition of restrictions or obligations on the Company's activities, including but not limited to the restricting or prohibiting of drilling.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of the Clean Water Act ("CWA"), imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and for a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company could be liable for costs and damages.

Clean Air Act. The Clean Air Act ("CAA)" regulates emissions of pollutants from stationary and mobile sources and establishes National Ambient Air Quality Standards ("NAAQS") for pollutants of concern. The CAA directs states to develop state implementation plans to achieve these standards and gives the primary role of enforcing this plans to the states. Federal and state laws generally require new and modified sources of air pollutants to obtain permits prior to commencing construction, which may require, among other things, stringent emission controls. Administrative agencies can bring actions for failure to comply with air pollution regulations or permits and generally enforce compliance through administrative, civil or criminal enforcement actions, which may result in fines, injunctive relief and imprisonment.

The New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs under the Clean Air Act ("CAA") impose specific requirements under both programs for compressors, controllers, dehydrators, storage tanks, natural gas processing plants, completions and certain other equipment. Periodic review and revision of these rules by federal and state agencies may require changes to our operations, including possible installation of new equipment to control emissions. We continuously evaluate the effect of new rules on our business.

In May 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, although the rules are currently the subject of litigation and in June 2017, the EPA proposed a 2-year stay of the rules. In November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands, although the present administration published a rule in December 2017 that delays the implementation dates applicable to requirements under these rules. Several states, including Colorado and Pennsylvania, are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. Furthermore, in September 2017, Utah proposed regulations implementing a new permit-by-rule system for emissions from new and existing oil and gas sources. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. The EPA has also adopted new rules under the CAA that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant.

Clean Water Act. The Clean Water Act ("CWA") and analogous state laws restrict the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined to include, among other things, certain wetlands. Under the Clean Water Act, permits must be obtained for the discharge of pollutants into waters of the United States. The CWA provides for administrative, civil and criminal penalties for unauthorized discharges, both routine and accidental, of pollutants and of oil and hazardous substances. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require permits to discharge storm water runoff, including discharges associated with construction activities. The CWA also prohibits the discharge of fill materials to regulated waters including wetlands without a permit. In addition, the EPA and the Army Corps of Engineers ("Corps") released a rule to revise the definition of "waters of the United States" ("WOTUS") for all Clean Water Act programs, which went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit stayed the WOTUS rule nationwide pending further action of the court. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States" and in June 2017 formally proposed to rescind the new WOTUS rules and promulgate the regulatory test that existed prior to the effective date of the new WOTUS rules. Currently, regulations are being implemented as they were prior to the effective date of the new WOTUS rule. The new WOTUS rules, if they were to become effective and no rescinded, could significantly expand federal control of land and water resources across the U.S., triggering substantial additional permitting and regulatory requirements.

Also, in 2016, the EPA finalized new wastewater pretreatment standards that prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works, permitting several years until compliance will be enforced. This pending restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Endangered Species Act. The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act, and special protections are provided to bald and golden eagles under the Bald and Golden Eagle Protection Act. The Company conducts operations on federal and other oil and natural gas leases that have species, such as raptors, that are listed and species, such as sage grouse, that could be listed as threatened or endangered under the ESA. In the case of sage grouse, in October 2017, the U.S. Fish and Wildlife Service announced the beginning of a scoping process to solicit public comments on Greater Sage-Grouse land management that could warrant land plan use amendments relating to the sage grouse. On February 11, 2016, the U.S. Fish and Wildlife Service published a final policy which alters how it identifies critical habitat for endangered and threatened species. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development. Moreover, the U.S. Fish and Wildlife Service continues its six-year effort to make listing decisions and critical habitat designations where necessary for over 250 species, as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia, and many hundreds of additional anticipated listing decisions have already been identified beyond those recognized in the 2011 settlement. A small portion of the lands operated by the Company in Utah have been designated on behalf of the hookless cactus, but the Company does not expect this designation to interfere with development of the properties. If the Company were to have other portions of its leases designated as critical or suitable habitat for the hookless cactus or any other protected species, it may adversely impact the value of the affected leases.

Climate Change Legislation. More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs"), including methane and carbon dioxide, may be adopted and could cause the Company to incur material expenses in complying with them. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements as applicable to GHG emissions, it upheld the EPA's authority to control GHG emissions when a permit is requir ed due to emissions of other pollutants. The EPA has established GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Ultra has submitted all required annual reports to date. Although the rule does not limit the amount of GHGs that can be emitted, it could require us to incur significant costs to monitor, keep records of, and report GHG emissions associated with our operations.

The EPA has also adopted regulations that seek to reduce GHG emissions. For example, in August 2015, the EPA issued its final Clean Power Plan rules, which seek to reduce carbon dioxide emissions from power plants by 32 percent from 2005 levels by 2030; however, on February 9, 2016, the U.S. Supreme Court stayed the implementation of the plan while it is being challenged in court and on October 10, 2017, the EPA proposed the repeal of the Clean Power Plan. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rule includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. These rules also are the subject of litigation and proposed stays.

Although the current administration has announced the intention to withdraw, the U.S. is currently a party to the Paris Agreement, which aims to reduce global greenhouse emissions. In addition to possible federal regulations, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These or other potential federal and state initiatives may result in so-called cap-and-trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in the Company incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from its operations. These regulatory initiatives also could adversely affect the marketability of the oil and natural gas the Company produces.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by our customers or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Worker Safety. The Occupational Safety and Health Act ("OSHA") and analogous state laws regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties. In December 2015, the U.S. Departments of Justice and Labor announced a plan to more frequently and effectively prosecute worker health and safety violations, including enhanced penalties.

The Company believes that it is in substantial compliance with current applicable environmental and occupational health and safety laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

Employees

As of December 31, 2017, the Company had 166 full-time employees, including officers.

Competition

The oil and gas industry is intensely competitive, and we compete with other companies in our industry that have more extensive resources than we do or that may have other competitive advantages or disadvantages. We compete with other companies in the acquisition of properties, in the search for and development of reserves, in the production and sale of natural gas and crude oil, and for the labor and equipment required to conduct our operations. Our competitors include major oil and natural gas companies, other independent oil and natural gas companies, and individual producers and operators.

Item 1A.*Risk Factors.*

An investment in our common stock involves certain risks. If any of the following key risks were to occur, it could have a material adverse effect on our financial position, results of operations, and cash flows. In any such circumstance and others described below, the trading price of our securities could decline and investors could lose part or all of their investment.

We emerged from bankruptcy on April 12, 2017, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our emergence from chapter 11 bankruptcy proceedings could adversely affect our business and relationships with customers, employees, and suppliers. Due to uncertainties, many risks exist, including the following:

- Key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- The ability to renew existing contracts and compete for new business may be adversely affected;
- The ability to attract, motivate, and/or retain key executives and employees may be adversely affected;
- Employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- Competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial conditions, and reputation. We cannot assure you that having been subject to bankruptcy protections will not adversely affect our operations in the future.

Our business could suffer if we lost the services of, or fail to attract and retain, key personnel.

The success of our business depends on our ability to attract and retain key personnel. In January 2018, Mr. Michael D. Watford announced his retirement from his positions at the Company, which include serving as Chairman of the Board of Directors, Chief Executive Officer and President of the Company, and two other members of our Board of Directors tendered their resignation from our Board of Directors. Mr. Watford's retirement and our board members' resignations will be effective February 28, 2018. The loss of the services of these individuals could have a material adverse effect on our operational and financial results in the future. We do not maintain any "key-man" insurance policies on any of our senior management, and we do not have any plans to obtain such insurance in the future.

Furthermore, our ability to attract and retain key personnel may be difficult in light of our emergence from the chapter 11 cases, the uncertainties and challenges currently facing our business and the crude oil and natural gas industry generally, the uncertainties and challenges associated with the changes in key personnel described above as well as other changes we may make to our organizational structure to adjust to changing circumstances from time to time. If additional executives, directors, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner or we may not be able to replace them with personnel of comparable skill, experience or expertise, and, as a result, we could experience significant declines in productivity.

Transfers or issuances of our equity may impair our ability to utilize our income tax net operating loss carryforwards in future years.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income net operating losses carried forward from prior years. We have U.S. federal net operating loss carryforwards of approximately $2.1 billion as of December 31, 2017. Our ability to utilize our net operating loss carryforwards to offset future taxable income and to reduce federal income tax liability may be substantially limited if we experience an "ownership change," as defined in section 382 of the U.S. Internal Revenue Code, which could have a negative impact on our financial position and results of operations. Generally, there is an "ownership change" if one or more shareholders owning 5% or more of a corporation's common stock have aggregate increases in their ownership of such stock of more than 50 percentage points over the prior three-year period. An "ownership change" occurred when our chapter 11 plan of reorganization became effective. A further "ownership change" is possible now that we have emerged from chapter 11. Under section 382 of the U.S. Internal Revenue Code, absent an applicable exception, if a corporation undergoes an "ownership change," the amount of its pre-ownership change net operating losses that may be utilized to offset future taxable income generally will be subject to an annual limitation equal to the value of its stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate, plus an additional amount calculated based on certain "built in gains" in our assets that may be deemed to be realized within a 5-year period following any ownership change. The ownership change that occurred as a result of our exit from chapter 11 proceedings should not materially limit our ability to utilize our net operating loss carryforwards, but it may be affected by future ownership changes, if any. There can be no assurance that we will be able to utilize our federal income tax net operating loss carry-forwards to offset future taxable income.

If we cannot obtain sufficient capital when needed, we will not be able to continue with our historical business strategy.

Our business strategy has historically included maintaining a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our historical business strategy, we may be required to curtail operations, which could adversely affect our financial condition and results of operations.

Our operations could be adversely affected if we fail to maintain required bonds.

Federal and state laws require bonds or cash deposits to secure our obligations with respect to various parts of our operations. Our failure to maintain, or inability to acquire, bonds that are required by state and federal law would have a material adverse effect on us. That failure could result from a variety of factors including: (i) our failure to comply with rules and regulations of Federal and state governmental agencies, including the United States Bureau of Land Management, (ii) the lack of availability of bonding, higher expense or unfavorable market terms of new bonds; (iii) and the exercise by third-party bond issuers of their right to refuse to renew the bonds. If we fail to maintain required bonds, our production may significantly decrease, which would significantly decrease our cash flow.

We cannot control the future price of oil and natural gas and sustained periods of low prices could hurt our profitability and financial condition and could impair our ability to grow our business or to perform the obligations in our agreements, including the agreements governing our indebtedness.

Sustained periods of low commodity prices will adversely affect our operations and financial condition. Our revenues, profitability, liquidity, ability to raise capital for our business, future growth, ability to operate, develop and explore our properties, and the carrying value of our properties depend heavily on prevailing prices for oil and natural gas.

Natural gas comprised approximately 94% of our total production for the year ended December 31, 2017 and represented 95% of our total proved reserves as of December 31, 2017. Historically, natural gas prices have been highly volatile, including in the Rocky Mountain region of the United States where the vast majority of our natural gas is produced. Prices have been affected by actions of federal, state and local governments and agencies, foreign governments, national and international economic and political conditions, levels of consumer demand, weather conditions, domestic and foreign supply of oil and natural gas, proximity and capacity of gas pipelines and other transportation facilities, the price and availability of equipment, materials and personnel to conduct operations, and the price and availability of alternative fuels. These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of natural gas. Any substantial or extended decline in the price of natural gas will have a material adverse effect on our financial condition and results of operations, including reduced cash flow and borrowing capacity, and lower proved reserves. Price volatility also makes it difficult to budget for and project the return on potential acquisitions and development and exploration projects, and sustained lower gas prices have caused and may, in the future continue to cause, us or the operators of properties in which we have ownership interests to curtail projects and limit or suspend drilling, completion or even production activities.

Crude oil comprised approximately 6% of our total production for the year ended December 31, 2017 and represented 5% of our total proved reserves as of December 31, 2017. Crude oil prices declined substantially from late 2014 through early 2016 and have remained flat during the year ended December 31, 2017. In the future, crude oil prices may remain at current levels or fall to lower levels. If crude oil prices remain at current levels or fall to lower levels, this will adversely affect our crude oil operations and our financial condition. Most of the production from our Uinta Basin properties is crude oil. At current oil prices, it is not profitable for us to drill and complete new wells on our Uinta Basin properties.

In addition, because we are significantly leveraged, a substantial decrease in our revenue due to low commodity prices is currently impairing and may in the future continue to impair our ability to satisfy payment obligations on our indebtedness and reduce funds available for operations and future business opportunities.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future.

The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;

- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is currently sold at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. Lower oil and natural gas prices will reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices could render uneconomic a significant portion of our identified drilling locations, and, may cause us to make significant downward adjustments to our estimated proved reserves or to be unable to claim proved undeveloped reserves at all. If oil and natural gas prices experience a substantial or extended decline from current levels, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures will be materially and adversely affected.

Our reserve estimates may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and 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, estimates of different engineers often vary. In addition, drilling, testing and production data acquired subsequent to the date of an estimate may justify revising such estimates. Accordingly, reserve estimates are often different from the quantities of oil, natural gas and NGLs that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, the timing and identification of future drilling locations, commodity prices, future production levels, costs and the ability to finance future development that may not prove correct over time. Predictions of future production levels, development schedules (particularly with regard to non-operated properties), commodity prices and future operating costs are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

The present value of net proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. In accordance with SEC requirements, we base the present value, discounted at 10%, of the pre-tax future net cash flows attributable to our net proved reserves on the average oil and natural gas prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, adjusted for quality and transportation fees. The costs to produce the reserves remain constant at the costs prevailing on the date of the estimate. Actual current and future commodity prices and costs may be materially higher or lower, and higher future costs and/or lower future commodity prices may impact whether development of our reserves in the future occurs as scheduled or at all. In addition, the 10% discount factor, which the SEC requires us to use in calculating our discounted future net revenues for reporting purposes, may not be the most appropriate discount factor based on our cost of capital from time to time and/or the risks associated with our business.

Competitive industry conditions may negatively affect our ability to conduct operations.

We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and natural gas companies as well as numerous independents, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill and complete wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties;
- our ability to comply with administrative, regulatory and other governmental requirements; and
- our ability to access pipelines, and the locations of facilities used to produce and transport oil and natural gas production.

Factors beyond our control affect our ability to effectively market production and may ultimately affect our financial results.

The ability to market oil and natural gas depends on numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and natural gas;
- the availability of pipeline, rail and refinery capacity, including facilities owned and operated by third parties;
- the availability of a market for our oil and natural gas production;
- the availability of satisfactory transportation arrangements for our oil and natural gas production;
- the proximity of natural gas production to natural gas pipelines;
- the effects of inclement weather;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- state and federal regulations of oil and natural gas marketing and transportation; and
- federal regulation of natural gas sold or transported in interstate commerce.

Because of these factors and other factors beyond our control, we may be unable to market all of the oil and natural gas that we produce or obtain favorable prices for such production.

The borrowing base under our revolving credit facility may be reduced, which could limit us in the future.

The borrowing base under our revolving credit facility is currently $1.4 billion, and lender commitments under our revolving credit facility are $425.0 million. The borrowing base is redetermined semi-annually under the terms of our revolving credit facility on April 1 and October 1. In addition, either we or the banks may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower commodity prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness, or for any other reason. In the event of a decrease in our borrowing based due to declines in commodity prices or otherwise, our ability to borrow under the revolving credit facility may be limited and we could be required to pay indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations, including any such debt repayment obligations.

Any derivative transactions we enter into may limit our gains and expose us to other risks.

We may enter into financial derivative transactions from time to time to manage our exposure to commodity price risks. These transactions limit our potential gains if commodity prices rise above the levels established by our derivative transactions. These transactions may also expose us to other risks of financial losses, for example, if our production is less than we anticipated at the time we entered into a derivative instrument or if a counterparty to our derivative instruments fails to perform its obligations under a derivatives transaction.

Legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd–Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) establishes federal oversight and regulation of over-the-counter (“OTC”) derivatives and requires the U.S. Commodity Futures Trading Commission (the “CFTC”) and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on November 5, 2013, a proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas) and for swaps that are their economic equivalents. Certain specified types of hedging transactions are exempt from these position limits, provided that such hedging transactions satisfy the CFTC’s requirements for “bona fide hedging” transactions or positions. Similarly, the CFTC has issued a proposed rule on margin requirements for swap transactions, which proposes an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions. In addition, the CFTC has issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or margin requirements, depending on the Company's ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may require us to comply with position limits, margin requirements and with certain clearing and trade-execution requirements in connection with our financial derivative activities. The Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of commercial end-users to have access to financial derivatives to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

Compliance with environmental and occupational safety and health laws and other government regulations could be costly and could negatively impact our production.

Our operations are subject to numerous and complex laws and regulations relating to environmental and occupational protection. These laws and regulations, which are continuously being reviewed for amendment and/or expansion, may:

- require that we acquire permits before developing our properties;
- restrict the substances that can be released into the environment in connection with drilling, completion and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, including plugging previously abandoned wells.

Under these laws and regulations or under the common law, we could be liable for personal injury and clean-up costs and other environmental, natural resource and property damages, as well as administrative, civil and criminal penalties or injunctions. Failure to comply with these laws and regulations could also result in the occurrence of delays or restrictions in permitting or performance of projects, or the issuance of orders and injunctions limiting or preventing operations relating to our properties in some areas. Under certain environmental laws and regulations, an owner or operator of our properties could be subject to strict, joint and several strict liability for the investigation, removal or remediation of previously released materials or property contamination, regardless of whether the owner or operator was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time the release or contamination occurred. Private parties, including the owners of properties upon which wells are drilled or facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, to seek damages for contamination or for personal injury or property damage. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by accidental environmental damages. Accordingly, we may be subject to liability in excess of our insurance coverage or may be required to cease production from properties in the event of material environmental damages.

We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine and other equipment emissions, greenhouse gases and hydraulic fracturing. Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by Ultra or other operators of the properties to attain and maintain compliance and may otherwise have a material adverse effect on the results of operations, competitive position or financial condition of Ultra or such other operators. Increased scrutiny of the oil and natural gas industry may occur as a result of EPA's FY2017-2019 National Enforcement Initiatives, through which the EPA will purportedly address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.

A significant percentage of our operations are conducted on federal and state lands. These operations are subject to a wide variety of regulations as well as other permits and authorizations which must be obtained from and issued by state and federal agencies. To conduct these operations, we may be required to file applications for permits, seek agency authorizations and comply with various other statutory and regulatory requirements. Complying with any of these requirements may adversely affect our ability to complete our drilling programs at the costs and in the time periods anticipated.

Climate change legislation or regulations restricting emissions of "greenhouse gases" ("GHGs") could result in increased operating costs and reduced demand for the oil and gas we produce.

More stringent laws and regulations relating to climate change and GHGs may be adopted and could cause us to incur material expenses to comply with such laws and regulations. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, as applicable only to GHG emissions, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA also requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of GHG emissions from such facilities is required on an annual basis. We will continue to incur costs associated with this reporting obligation.

In May 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, although the rules are currently the subject of litigation and in June 2017, the EPA proposed a 2-year stay of the rules. In November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands, although the present administration is proposing to delay the implementation dates applicable to requirements under these rules. Several states, including Colorado and Pennsylvania, are pursuing similar measures to regulate emissions of methane from new and existing sources within the oil and natural gas source category. Furthermore, in September 2017, Utah proposed regulations implementing a new permit-by-rule system for emissions from new and existing oil and gas sources.

In addition, the United States Congress has considered legislation to reduce emissions of GHGs and many states and regions have already taken legal measures to reduce or measure GHG emission levels, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs require major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to reduce overall GHG emissions. The cost of these allowances could escalate significantly over time. On an international level, almost 200 nations agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. Although the present administration has announced its intention to withdraw from the Paris accord, several states and local governments remain committed to its principles in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the international climate change agreement. The adoption and implementation of any legislation or regulatory programs imposing GHG reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Potential physical effects of climate change could adversely affect our operations and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations, including the hydraulic fracturing of our wells, have the potential to be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from powerful winds or floods, or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions; however, EPA has taken certain actions with respect to regulating hydraulic fracturing. For example, EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in May 2016 (which are currently the subject of litigation and a proposed regulatory stay) governing performance standards for the oil and natural gas industry; issued in June 2016 final effluent limitations guidelines under the CWA that waste water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, the U.S. District Court of Wyoming struck down this rule in June 2016 and the ruling is currently on appeal before the U.S. Tenth Circuit Court of Appeals. The BLM also issued new rules in November 2016 which seek to limit methane emissions from new and existing oil and gas operations on federal lands, although the present administration is proposing to delay the implementation dates applicable to the requirements under these rules.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Wyoming has adopted regulations requiring producers to provide detailed information about wells they hydraulically fracture in that state. Some states have adopted or are considering adopting regulations requiring disclosure of chemicals in fluids used in hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; restrictions on access to, and usage of, water; and restrictions on the type of chemical additives that may be used in hydraulic fracturing operations. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. We have conducted hydraulic fracturing operations on most of our existing wells, and we anticipate conducting hydraulic fracturing operations on substantially all of our future wells. As a result, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities and adversely affect our operations and financial condition.

Changes in tax laws and regulations, including interpretations thereof, or in our operations may impact our effective tax rate and may adversely affect our business, financial condition and operating results.

Tax interpretations, regulations, and legislation in the various jurisdictions in which we and our affiliates operate are subject to measurement uncertainty and the interpretations can impact net income, income tax expense or recovery, and deferred income tax assets or liabilities. In addition, tax rules and regulations, including those relating to foreign jurisdictions, are subject to interpretation and require judgment by us that may be challenged by the taxation authorities upon audit. Changes in tax laws in any of the multiple jurisdictions in which we operate could result in an unfavorable change in our effective tax rate, which could adversely affect our business, financial condition, and operating results.

The effects of the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (hereinafter, “Tax Cuts and Jobs Act”) on our business have not been fully analyzed and could have an adverse effect on our net income.

On December 22, 2017, the Tax Cuts and Jobs Act (“TCJA”) was enacted and made significant changes to the U.S. Internal Revenue Code. Such changes include a reduction in the corporate tax rates and limitation on certain deductions and credits, among other changes. In addition, adverse changes in the underlying profitability and financial outlook of our operations and changes in tax law could lead to changes in our valuation allowance against deferred tax assets on our balance sheets, which could materially affect our results of operations. While we believe that the TCJA will not impact the ability of our deferred tax assets, as re-measured, including our significant U.S. Federal Net Operating Loss carryover, to reduce the amount or cash income taxes payable in the future, we are in the process of further analyzing the TCJA and its possible effects on us.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While our operations and financial condition have not been materially and adversely affected by cyber-attacks, there is no assurance that we will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Our business and the trading prices of our securities could be negatively impacted by the actions of so-called “activist” stockholders.

If we become the subject of activity by activist shareholders, this could disrupt our business, distract our management and Board of Directors, and negatively impact our business and the trading prices of our securities, including our common stock. Responding to shareholder activism can be costly and time-consuming, disrupt our operations, and divert the attention of management and our employees from our strategic initiatives. Furthermore, activist campaigns can create perceived uncertainties as to our future direction, strategy, or leadership and may result in the loss of potential business opportunities, harm our ability to attract new employees, investors, customers, and joint venture partners, and cause our stock price to experience periods of volatility.

If a sustained financial or economic downturn occurs domestically or internationally, capital market conditions and commodity prices may deteriorate, which could materially and adversely affect our liquidity, results of operations and ability to execute our business.

Global and domestic economic conditions are difficult for us to forecast and impossible for us to control. Similarly, conditions in global and domestic capital markets, including debt and equity markets, are difficult for us to forecast and impossible for us to control. Adverse changes, even material adverse changes, in global and domestic economic conditions and in domestic and international capital markets may occur without warning. Although there are steps we can take to anticipate and mitigate such changes, we may fail to do so. If we fail to successfully anticipate or mitigate such matters, adverse changes in global or domestic economic conditions or capital markets, especially materially adverse changes, could increase our costs, limit our financial flexibility, and materially and adversely affect our business, results of operations, and liquidity.

Unless we are able to replace reserves that we have produced, our cash flows and production will decrease over time.

Our future success depends on our ability to find, acquire, develop and produce additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We can give no assurance that we will be able to find, develop or acquire additional reserves at acceptable costs.

We may not be able to replace our reserves or generate cash flows if we are unable to raise capital. We will be required to make substantial capital expenditures to develop our existing reserves and to discover new oil and gas reserves.

Our ability to continue exploration and development of our properties and to replace reserves depends upon our ability to comply with our debt covenants, renegotiate our debt agreements, raise significant additional financing, or to seek and obtain other arrangements with industry participants in lieu of raising additional financing. Any arrangements that may be entered into could be expensive to us if such arrangements can be made at all. There can be no assurance that we will be able to raise additional capital in light of factors such as our financial condition, the market demand for our securities, the general condition of financial markets for independent oil and gas companies (including the markets for debt), oil and natural gas prices and general market conditions. See Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for a discussion of our capital budget. Continued periods of depressed commodity prices or further commodity price decreases could have a material adverse effect on our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. There can also be no assurance that we will be able to obtain other satisfactory arrangements to allow further exploration and development of our properties if we are unable to raise additional capital.

We expect to use our cash from operations, cash from draws on the Revolving Credit Facility (defined below) and cash on hand to fund our capital budget during 2018. The loan commitment and the aggregate amount of money that we can borrow under the Revolving Credit Facility (defined below) and from other sources is revised from time to time based on certain restrictive covenants. A change in our ability to meet the restrictive covenants may limit our ability to borrow. If this occurred, we may have to sell assets or seek substitute financing. We can make no assurances that we would be successful in selling assets or arranging substitute financing. See Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for information about our liquidity, available cash on hand, and the description of the current debt agreements.

Our operations may be interrupted by severe weather or drilling restrictions.

Our operations are conducted primarily in the Rocky Mountain region of the United States. The weather in this area can be extreme and can cause interruption in our exploration and production operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital investment. Likewise, our operations are subject to disruption from winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

The oil and natural gas business involves a variety of operating risks, including blowouts, fire, explosion, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, natural gas leaks, discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids, including chemical additives. The occurrence of any of these events with respect to any property we own or operate (in whole or in part) could have a material adverse impact on us. We and the operators of our properties maintain insurance in accordance with customary industry practices and in amounts that management believes to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

There are risks associated with our drilling activity that could impact our results of operations.

Our oil and natural gas operations are subject to all of the risks and hazards typically associated with drilling, completion, production and transportation of, oil and natural gas. These risks include the necessity of spending large amounts of money for identification and acquisition of properties and for drilling and completion of wells. In the drilling and completing of wells, failures and losses may occur before any deposits of oil or natural gas are found and produced. The presence of unanticipated pressure or irregularities in formations, blow-outs or accidents may cause such activity to be unsuccessful, resulting in a loss of our investment in such activity and possible liabilities. If oil or natural gas is encountered, there can be no assurance that it can be produced in quantities sufficient to justify the cost of continuing such operations or that it can be marketed satisfactorily.

Our decision to drill a prospect is subject to a number of factors which may alter our drilling schedule or our plans to drill at all.

A prospect is an area in which our geoscientists have identified what they believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill our prospects depends on many factors, including but not limited to: the availability and cost of capital; receipt of additional seismic data or reprocessing of existing data; material changes in current of future expected oil or natural gas prices; the costs and availability of drilling and completion equipment; the success or failure of wells drilled in similar formations or which would use the same production facilities and equipment; changes in the estimates of costs to drill or complete wells; decisions of our joint working interest owners; and regulatory, permitting and other governmental requirements. It is possible these factors and others may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

We have limited control over activities conducted on properties we do not operate.

We own interests in properties that are operated by third parties. The success, timing and costs of drilling, completion, and other development activities on our non-operated properties depend on a number of factors that are beyond our control. Because we have only a limited ability to influence and control the operations of our non-operated properties, we can give no assurances that we will realize our targeted returns with respect to those properties.

Our business depends on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities would interfere with our ability to market the oil and natural gas that we produce.

The marketability of our oil and natural gas production will depend in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering or transportation system, or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity, or significant delay in the construction of necessary gathering and transportation facilities, could adversely affect our business, results of operations, financial condition and prospects.

We may fail to fully identify problems with any properties we acquire.

We acquired a portion of our acreage position in Wyoming and Utah through property acquisitions and acreage trades, and we may acquire additional acreage in these or other regions in the future. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify.

Our acquisitions may perform worse than we expected or prove to be worth less than what we paid because of uncertain factors and matters beyond our control. In addition, our acquisitions could expose us to potentially significant liabilities.

When we make acquisitions of oil and gas properties, we make assumptions about many uncertain factors, including estimates of recoverable reserves, expected timing of recovering acquired reserves, future commodity prices, expected development and operating costs, and other matters, many of which are beyond our control. Assumptions about uncertain factors may be wrong, and the properties we acquire may perform worse than we expect, materially and adversely affecting our operations and financial condition.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Since our business depends on the level of activity in the oil and natural gas industry, any improvement in or new discoveries of alternative energy technologies that increase the use of alternative forms of energy and reduce the demand for oil and natural gas could have a material adverse effect on our business, financial condition, and operations.

Any future implementation of price controls on oil and natural gas would affect our operations.

The United States Congress may in the future impose some form of price controls on either oil, natural gas, or both. Any future limits on the price of oil or natural gas could negatively affect the demand for our services and consequently, have a material adverse effect on our business, financial condition, and results of operations.

Forward-Looking Statements

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. Except for statements of historical facts, all statements included in this document, including those statements preceded by, followed by or that otherwise include the words "believe," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," or similar expressions or variations on such expressions are forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct.

Forward-looking statements include statements regarding:

- our oil and natural gas reserve quantities, and the discounted present value of those reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;
- our ability to respond to low natural gas prices;
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- volatility and, especially, declines or substantial declines and weakness in natural gas or oil prices;
- our ability to maintain adequate liquidity in view of current natural gas prices;
- our ability to comply with the covenants and restrictions of the agreements governing our indebtedness, or our ability to amend or replace the agreements governing our indebtedness;
- any future global economic downturn;
- general economic conditions, including the availability of credit and access to existing lines of credit;
- conditions in capital markets, including the availability of capital to companies in the oil and gas business;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- our decisions about how we allocate capital and resources among strategic opportunities;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- reductions in our borrowing base under our revolving credit facility;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business, including those related to climate change and greenhouse gases, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and the use of water, and financial derivatives and hedging activities;
- actions of operators of our oil and natural gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Location and Characteristics

The Company owns oil and natural gas leases in Wyoming and Utah. The Company owned natural gas leases in Pennsylvania, which the Company sold during the quarter ended December 31, 2017. In Colorado, the Company owns oil and natural gas leases as well as fee oil and gas rights. The leases in Wyoming are primarily federal leases with 10-year lease terms until establishment of production. Production extends the lease terms until cessation of that production. The leases in Utah are from private individuals and companies, the State of Utah, and the federal government with primary lease terms ranging from five to ten years until the establishment of production. In 2014, the Company sold the surface rights to its undeveloped acreage in Colorado Springs, Colorado while retaining the oil and gas rights. The Company has no immediate plans for further exploration in Colorado during 2018.

Green River Basin, Wyoming

As of December 31, 2017, the Company owned oil and natural gas leases totaling approximately 112,000 gross (77,000 net) acres in southwest Wyoming's Green River Basin. Most of this acreage covers the Pinedale and Jonah fields. Of the total acreage position in Wyoming and as of December 31, 2017, approximately 39,000 gross (25,000 net) acres were developed, and 73,000 gross (52,000 net) acres were undeveloped. The developed portion represents 83% of the Company's total developed net acreage while the undeveloped portion represents approximately 95% of the Company's total undeveloped net acreage. The Company operates 89% of its acreage position in the Pinedale field and 89% of its production.

Lease maintenance costs in Wyoming were approximately $0.6 million for the year ended December 31, 2017. The Company currently owns 67 leases totaling 79,000 gross (54,000 net) acres that are held by production and activities ("HBP"). The HBP acreage includes all of the Company's leases within the productive area of the Pinedale and Jonah fields.

Development Wells. Development wells are wells that were drilled in the current year that were proved undeveloped locations in the prior year's reserve report. During 2017, none of the productive wells drilled by the Company are considered to be development wells.

Exploratory Wells. Exploratory wells are wells that were drilled in the current year that were not proved undeveloped locations in the prior year's reserve report. During 2017, all of the productive wells drilled by the Company are reported as exploratory wells and totaled 210 gross (172.1 net) productive exploratory wells on the Green River Basin properties. At December 31, 2017, there were 23 gross (17.4 net) additional exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth and thus a determination of productive capability could not be made at year-end. As Ultra did not report proved undeveloped reserves at December 31, 2016, all wells drilled in 2017 are considered exploratory wells.

Seismic Activity. The Company owns 492 square miles of 3D seismic data in Wyoming which, when overlap is subtracted, covers 415 square miles. The data consists of both proprietary data and data licensed from independent seismic contractors, and provides coverage over the entire productive areas of Pinedale and Jonah fields. During 2016, the Company completed a project to merge the various data sets and reprocess the entire volume.

Uinta Basin, Utah

As of December 31, 2017, the Company owned oil and natural gas leases covering 8,000 gross (8,000 net) acres in the Uinta Basin. This acreage is located in Uintah County in the eastern portion of the Uinta Basin. As of December 31, 2017, approximately 5,000 gross (5,000 net) acres were developed, and 3,000 gross (3,000 net) acres were undeveloped. The developed portion represents 17% of the Company's total developed net acreage position while the undeveloped portion represents 5% of the Company's total undeveloped net acreage position. The Company operates 100% of the properties.

Lease maintenance costs in Utah for the year ended December 31, 2017 were not significant. The Company owns approximately 7,000 gross (7,000 net) acres currently held by production or activities in Utah.

Development Wells. During 2017, the Company did not participate in the drilling of any development wells on the Utah properties. At December 31, 2017, there were no development wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth.

Exploratory Wells. During 2017, the Company did not participate in the drilling of any exploratory wells on the Utah properties. At December 31, 2017, there were no exploratory wells that commenced during the year that were either still drilling or had operations suspended at a depth short of total depth.

Waterflood. In 2017, the Company continued its waterflood program with incremental recovery achieved in both pilots. A third pilot has been planned and permitted, but operations have not yet been implemented.

Seismic Activity. The Company's 3D seismic coverage in Utah covers approximately 27 square miles, partially covering its properties.

Pennsylvania

During the fourth quarter of 2017, the Company sold the oil and gas leases covering 144,000 gross (72,000 net) acres in the Pennsylvania portion of the Appalachian Basin for a cash purchase price of approximately $115.0 million, subject to post-close adjustments. This acreage is located in the heart of northeast Pennsylvania's Marcellus Shale Gas Trend, principally in Lycoming, Clinton and Centre counties. The Company's properties in Pennsylvania were non-operated.

Lease maintenance costs in Pennsylvania were approximately $0.1 million for the year ended December 31, 2017.

Development Wells. During 2017, the Company did not participate in the drilling of any development wells on the Pennsylvania properties.

Exploratory Wells. During the year ended December 31, 2017, the Company did not participate in the drilling of any exploratory wells on the Pennsylvania properties.

Oil and Gas Reserves

The following table sets forth the Company's quantities of proved reserves for the years ended December 31, 2017, 2016, and 2015. The table summarizes the Company's proved reserves, the estimated future net revenues from these reserves and the standardized measure of discounted future net cash flows attributable thereto at December 31, 2017, 2016 and 2015. During 2014, the Company acquired contracts related to NGLs providing an annual election to process NGLs beginning in 2017. During 2017, the Company renegotiated its existing gas processing contracts in Wyoming. The new gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves. As of December 31, 2017, proved undeveloped reserves represent 23% of the Company's total proved reserves. The Company did not record any proved undeveloped reserves for the years ended December 31, 2016 and 2015 because of the going concern assessment for those respective periods.

	December 31,		
	2017	2016	2015
	($ amounts in thousands, except per unit data)		
Proved Developed Reserves			
Natural gas (MMcf)	2,261,289	2,321,613	2,336,280
Oil (MBbl)	21,652	21,475	22,175
Natural gas liquids (MBbl)	71	9,903	9,840
Proved Undeveloped Reserves			
Natural gas (MMcf)	694,703	—	—
Oil (MBbl)	5,466	—	—
Natural gas liquids (MBbl)	—	—	—
Total Proved Reserves (MMcfe) (1)	3,119,126	2,509,881	2,528,370
Estimated future net cash flows, before income tax	$ 4,377,344	$ 2,791,229	$ 2,946,982
Standardized measure of discounted future net cash flows, before income taxes (2)	$ 2,384,328	$ 1,690,946	$ 1,865,649
Future income tax	$ —	$ —	$ —
Standardized measure of discounted future net cash flows, after income tax	$ 2,384,328	$ 1,690,946	$ 1,865,649
Calculated average price (3)			
Gas ($/Mcf)	$ 2.59	$ 2.07	$ 2.21
Oil ($/Bbl)	$ 48.05	$ 37.90	$ 42.36
NGLs ($/Bbl)	$ 26.85	$ 19.17	$ 20.61

(1) Oil, condensate and NGLs are converted to natural gas at the ratio of one barrel of liquids to six Mcf of natural gas. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or condensate to an Mcf of natural gas.

(2) Management believes that the presentation of the standardized measure of discounted future net cash flows, before income taxes, of estimated proved reserves, discounted at 10% per annum, may be considered a non-Generally Accepted Accounting Principle financial measure as defined in Item 10(e) of Regulation S-K, therefore the Company has included this reconciliation of the measure to the most directly comparable Generally Accepted Accounting Principle ("GAAP") financial measure (standardized measure of discounted future net cash flows, after income taxes). Management believes that the presentation of the standardized measure of future net cash flows before income taxes provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of the Company's oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of the Company's reserves to other companies. The standardized measure of discounted future net cash flows, before income taxes, is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. Standardized measure of discounted future net cash flows, before income taxes, should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(3) As prescribed by SEC rules, our reserve estimates at December 31, 2017, 2016 and 2015, reflect spot prices based on the average of the beginning of the month prices during the 12-month period before the ending date of the period covered by this report determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period.

Since January 1, 2016, no crude oil, natural gas or NGL reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

Proved Undeveloped Reserves

Changes in proved undeveloped reserves: Changes to the Company's proved undeveloped reserves (PUDs) during 2017 are summarized in the table below. These changes include updates to prior PUDs, the addition of new PUDs associated with the current development plans, the transfer of PUDs to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years. The Company annually reviews all PUDs to ensure an appropriate plan for development exists. As of December 31, 2017, 100% of the proved undeveloped locations are located in Wyoming.

	MMcfe
Proved undeveloped reserves, December 31, 2016	—
Converted to proved developed	—
Proved undeveloped reserve extensions	39,093
Proved undeveloped reserves purchased	3,151
Proved undeveloped reserves transferred to unproven	—
Proved undeveloped reserve revisions	685,255
Proved undeveloped reserves, December 31, 2017	727,499

Conversions: Due to going concern issues related to the Company's chapter 11 proceedings, no proved undeveloped reserves were recognized at December 31, 2016. As a result, there are no PUD conversions nor a conversion rate to report on an annual basis for the year ended December 31, 2017.

Additions/Extensions: In 2017, the Company's reserve additions primarily include initial bookings of horizontal PUDs in Pinedale.

Purchases: In 2017, the Company purchased certain assets in the Pinedale field. The divestiture of assets in Pennsylvania did not affect proved undeveloped reserves.

Transfers: At December 31, 2016, the Company did not book any PUD reserves. As a result, there are no transfers of PUDs to record in 2017.

Revisions: Due to the uncertainty of the Company's ability to fund a development plan as a result of the Company's chapter 11 proceedings, no proved undeveloped reserves were recognized at December 31, 2016. Upon emergence from chapter 11 proceedings the Company began recognizing PUDs as the substantial doubt regarding the Company's ability to continue as a going concern had been alleviated. The changes to the Company's PUDs during 2017 include the PUDs associated with the current development plan. In 2017, the Company's revisions include Pinedale drilling locations that are scheduled in its limited development plan within the next five years.

Internal Controls Over Reserve Estimating Process

Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC's regulations and GAAP. The Senior Director— Development is primarily responsible for overseeing the preparation of the Company's reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 15 years of experience.

The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation as well as ultimate approval of our capital budget and review of our development plan by our senior management and Board of Directors. The development plan underlying the Company's PUD reserves, if any, is further subject to internal controls, including a comparison of future development costs to historical expenditures as well as our future development plan and financial capabilities, and an evaluation of the estimated profitability of each location at the time the report is prepared. The development plan underlying the Company's proved undeveloped reserves, adopted every year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company's shareholders.

The estimates of proved reserves and future net revenue as of December 31, 2017 are based upon the use of technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, these estimates necessarily represent only informed professional judgment.

The Company engaged Netherland, Sewell & Associates, Inc. ("NSAI"), a third-party, independent engineering firm, to prepare the reserve estimates for all of the Company's assets for the years ended December 31, 2017, 2016 and 2015 in this annual report.

Our internal professional staff works closely with our independent engineers, NSAI, to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves. The report of NSAI is included as an Exhibit to this annual report.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. ("NSAI"), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F 2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Sean A. Martin and Mr. Philip R. Hodgson. Mr. Martin, a Licensed Professional Engineer in the State of Texas (No. 125354), has been practicing consulting petroleum engineering at NSAI since 2014 and has over 7 years of prior industry experience. He graduated from University of Florida in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Table of Contents

Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for and average production costs associated with the Company's sale of oil and natural gas for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	260,009	264,278	268,954
Oil (Bbl)	2,775	2,912	3,533
Total (Mcfe)	276,659	281,748	290,149
Revenues			
Natural gas sales	$ 748,682	$ 609,756	$ 696,730
Oil sales	133,368	111,335	142,381
Other revenues	9,823	—	—
Total revenues	$ 891,873	$ 721,091	$ 839,111
Lease Operating Expenses			
Lease operating expenses (a)	$ 92,326	$ 89,134	$ 106,906
Facility lease expense	21,749	20,686	20,647
Severance/production taxes	91,067	69,737	72,774
Gathering	86,953	86,809	87,904
Total lease operating expenses	$ 292,095	$ 266,366	$ 288,231
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on commodity derivatives)	$ 2.92	$ 2.31	$ 3.14
Natural gas ($/Mcf, excluding realized gains (losses) on commodity derivatives)	$ 2.88	$ 2.31	$ 2.59
Oil ($/Bbl), including realized gains (losses) on commodity derivatives)	$ 48.05	$ 38.24	$ 40.31
Oil ($/Bbl), excluding realized gains (losses) on commodity derivatives)	$ 48.05	$ 38.24	$ 40.31
Costs per Mcfe			
Lease operating expenses	$ 0.33	$ 0.32	$ 0.37
Facility lease expense	$ 0.08	$ 0.07	$ 0.07
Severance/production taxes	$ 0.33	$ 0.25	$ 0.25
Gathering	$ 0.31	$ 0.31	$ 0.30
Transportation charges	$ —	$ 0.07	$ 0.29
DD&A	$ 0.59	$ 0.44	$ 1.38
General & administrative	$ 0.14	$ 0.03	$ 0.03
Interest	$ 1.31	$ 0.24	$ 0.59
Total costs per Mcfe	$ 3.09	$ 1.73	$ 3.28

The following table sets forth the net sales volumes, operating expenses and realized natural gas prices attributable to field(s) that contain 15% or more of our total estimated proved reserves as of December 31, 2017:

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Pinedale Field:			
Production (Mcfe)	256,695	256,881	261,498
Operating expenses	$ 265,051	$ 241,975	$ 253,214
Realized price ($/Mcf)	$ 2.90	$ 2.35	$ 2.66

(a) Lease operating costs include lifting costs and remedial workover expenses.

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. As of February 9, 2018, the Company has long-term natural gas delivery commitments of 12.6 MMMBtu in 2019 under existing agreements. As of February 9, 2018, the Company has long-term crude oil delivery commitments of 1.7 MMBbls in 2018 and 0.3 MMBbls in 2019 under existing agreements. None of these commitments require the Company to deliver gas or oil produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Item 1A. "Risk Factors". If for some reason our production is not sufficient to satisfy these commitments, subject to the availability of capital, we could purchase volumes in the market or make other arrangements to satisfy the commitments.

Productive Wells

As of December 31, 2017, the Company's total gross and net wells were as follows:

Productive Wells*	Gross Wells	Net Wells
Natural Gas	2,893	2,005
Crude Oil	139	139
Total	3,032	2,144

* Productive wells are producing wells, shut-in wells the Company deems capable of production, wells that are waiting for completion, plus wells that are drilled/cased and completed, but waiting for pipeline hook-up. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional working interests the company owns in gross wells.

Oil and Gas Acreage

The primary terms of the Company's oil and gas leases expire at various dates. Much of the Company's undeveloped acreage is held by production, which means that the Company will maintain its rights in these leases as long as oil or natural gas is produced from the acreage by it or by other parties holding interests in producing wells on those leases. In some cases, if production from a lease ceases, the lease will expire, and in some cases, if production from a lease ceases, the Company may maintain the lease by additional operations on the acreage.

The Company does not believe the remaining terms of its leases are material. The Company expects to maintain essentially all of the material leases among its oil and gas properties by production, operations, extensions or renewals. The Company does not expect to lose material lease acreage because of failure to drill due to inadequate capital, equipment or personnel. The Company has, based on its evaluation of prospective economics, allowed acreage to expire and it may allow additional acreage to expire in the future. The Company estimates that approximately 300 net acres of leases in Utah may expire in 2018 and approximately 400 net acres of leases in Utah and 6,700 net acres of leases in Wyoming may expire in 2019.

As of December 31, 2017, the Company had total gross and net developed and undeveloped oil and natural gas leasehold acres in the United States as set forth below.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Wyoming	39,000	25,000	73,000	52,000
Utah	5,000	5,000	3,000	3,000
All States	44,000	30,000	76,000	55,000

Drilling Activities

For each of the three fiscal years ended December 31, 2017, 2016 and 2015 the number of gross and net wells drilled by the Company was as follows:

Wyoming — Green River Basin

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	0.0	0.0	0.0	0.0	184.0	132.3
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	184.0	132.3

At year end, there were no development wells that were either drilling or had operations suspended. This includes wells in both the Pinedale and Jonah fields.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	210.0	172.1	94.0	68.6	7.0	3.8
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	210.0	172.1	94.0	68.6	7.0	3.8

At year end, there were 23 gross (17.4 net) additional exploratory wells that were either drilling or had operations suspended in the Pinedale field.

Utah

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	0.0	0.0	0.0	0.0	14.0	14.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	14.0	14.0

At year end, there were no additional development wells that were either drilling or had operations suspended.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	0.0	0.0	0.0	0.0	5.0	5.0
Dry	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	5.0	5.0

At year end, there were no additional exploratory wells that were either drilling or had operations suspended.

Pennsylvania

The Company divested its Pennsylvania assets during the fourth quarter of 2017. For the years ended December 31, 2017, 2016, and 2015, the Company did not drill any development or exploratory wells on its Pennsylvania acreage.

Colorado

The Company did not conduct any operations on this acreage during 2017, 2016 or 2015. During 2014, the Company sold the surface rights to its Colorado acreage and retained the mineral rights. The Company has no immediate plans for further exploration in this area during 2018.

Item 3. ***Legal Proceedings.***

Other Claims: See Note 11 for additional discussion of on-going claims and disputes that arose during our chapter 11 proceedings, certain of which may be material. The Company is also currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine or predict the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company's financial position, or results of operations.

Item 4. ***Mine Safety Disclosures.***

None.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Subsequent to emergence from chapter 11 proceedings, the Company's common shares have been traded on the NASDAQ (the "NASDAQ") under the symbol "UPL". From January 1, 2017 through the Effective Date, the Company's common shares traded on the over-the counter ("OTC) under the symbol "UPLMQ". In conjunction with emergence from chapter 11 proceedings, the Company issued new Common Shares to holders of existing pre-petition Common Shares (the "Existing Common Shares") at a conversion ratio of 0.521562 (the "New Equity"). As a result, the share price has been adjusted to reflect this conversion as if it had occurred on January 1, 2016. The following table sets forth the high and low intra-day sales prices of the common shares as reported in the New York Stock Exchange (the "NYSE")-Composite Transaction quotations for the periods indicated.

2017		**High**		**Low**
1st quarter	$	16.78	$	11.64
2nd quarter	$	14.82	$	9.54
3rd quarter	$	11.02	$	7.37
4th quarter	$	10.18	$	7.65
2016		**High**		**Low**
1st quarter	$	5.06	$	0.35
2nd quarter	$	4.10	$	0.31
3rd quarter	$	9.91	$	3.11
4th quarter	$	16.28	$	6.98

As of February 14, 2018, the last reported sales price of the common shares on the NASDAQ was $4.87 per share and there were approximately 541 holders of record of the common shares. The Company has not declared or paid and does not anticipate declaring or paying any dividends on its common shares in the near future. Additionally, our RBL Credit Agreement (defined below), Term Loan Agreement (defined below), and the indentures governing the Notes (defined below) place certain restrictions on our ability to pay cash dividends. The Company intends to retain its cash flow from operations for the future operation and development of its business.

The following share price performance graph is intended to allow review of shareholder returns, expressed in terms of the appreciation of the Company's common shares relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future share performance. The graph below matches the Company's cumulative total shareholder return on common stock since the Effective Date with the cumulative total returns of the NYSE Composite index and the Dow Jones US Exploration and Production TSM index. The graph tracks quarterly performance of a $100 investment in our common stock and each respective index (with the reinvestment of all dividends) from the Effective Date through December 31, 2017.

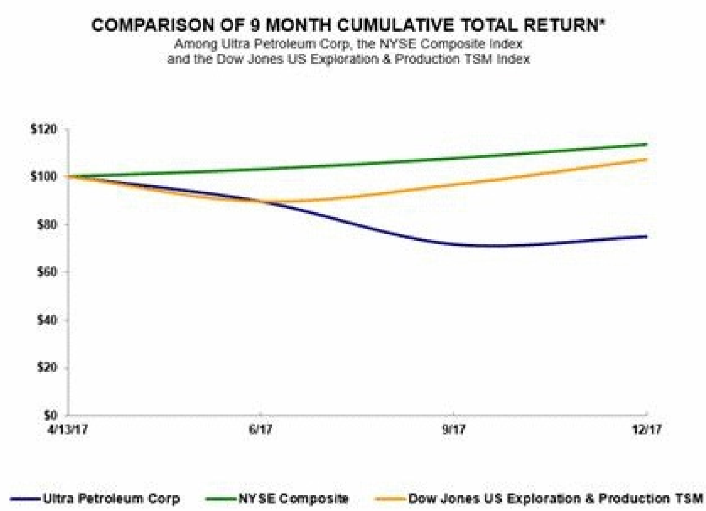

Table of Contents

Item 6. *Selected Financial Data.*

The selected consolidated financial information presented below for the years ended December 31, 2017, 2016, 2015, 2014 and 2013 is derived from the Consolidated Financial Statements of the Company.

	Year Ended December 31, 2017	2016	2015	2014	2013
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Natural gas sales	$ 748,682	$ 609,756	$ 696,730	$ 969,850	$ 824,266
Oil sales	133,368	111,335	142,381	260,170	109,138
Other revenues	9,823	—	—	—	—
Total operating revenues	891,873	721,091	839,111	1,230,020	933,404
Expenses:					
Production expenses and taxes	292,095	266,366	288,231	280,631	212,578
Transportation charges	—	20,049	83,803	77,780	82,797
Depletion, depreciation and amortization	161,945	125,121	401,200	292,951	243,390
Ceiling test and other impairments	—	—	3,144,899	—	—
General and administrative	39,548	9,179	7,387	19,069	22,373
Interest expense	361,367	66,565	171,918	126,157	101,486
Total operating expenses	854,955	487,280	4,097,438	796,588	662,624
Other:					
Gain (loss) on commodity derivatives	28,412	—	42,611	82,402	(46,754)
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553	10,553	10,553
Contract settlement	(52,707)	(131,106)	—	—	—
Gain on sale of property	—	—	—	8,022	—
Litigation expense	—	—	(4,401)	—	—
Restructuring expenses	—	(7,176)	—	—	—
Reorganization items, net	140,907	(47,503)	—	—	—
Other (expense) income, net	(237)	(3,082)	(2,060)	2,618	(357)
Total other income (expense), net	126,928	(178,314)	46,703	103,595	(36,558)
Income (loss) before income taxes	163,846	55,497	(3,211,624)	537,027	234,222
Income tax (benefit)	(13,294)	(654)	(4,404)	(5,824)	(3,616)
Net income (loss)	$ 177,140	$ 56,151	$ (3,207,220)	$ 542,851	$ 237,838
Basic Earnings (Loss) per Share:					
Net income (loss) per common share — basic (1)	$ 1.08	$ 0.70	$ (40.14)	$ 6.79	$ 2.97
Fully Diluted Earnings (Loss) per Share:					
Net income (loss) per common share — fully diluted (1)	$ 1.08	$ 0.70	$ (40.14)	$ 6.73	$ 2.95
Statement of Cash Flows Data (2):					
Net cash provided by (used in):					
Operating activities	$ 65,268	$ 311,070	$ 515,536	$ 712,582	$ 472,636
Investing activities	$ (435,311)	$ (278,900)	$ (512,757)	$ (1,600,743)	$ (1,093,519)
Financing activities	$ (16,737)	$ 368,621	$ (7,557)	$ 886,414	$ 618,624
Balance Sheet Data:					
Cash and cash equivalents	$ 16,631	$ 401,478	$ 4,143	$ 8,919	$ 10,664
Working capital (deficit)	$ (81,065)	$ 383,185	$ (3,560,683)	$ (168,580)	$ (278,845)
Oil and gas properties	$ 1,325,068	$ 1,010,466	$ 851,145	$ 3,878,937	$ 2,421,611
Total assets	$ 1,512,982	$ 1,540,928	$ 952,039	$ 4,225,690	$ 2,785,319
Total debt(3)(4)	$ 2,116,211	$ —	$ 3,390,000	$ 3,378,000	$ 2,470,000
Other long-term obligations	$ 197,728	$ 177,088	$ 165,784	$ 152,472	$ 91,932
Deferred income taxes, net	$ —	$ —	$ —	$ 992	$ —
Total shareholders' (deficit) equity	$ (1,154,636)	$ (2,928,151)	$ (2,991,937)	$ 211,660	$ (331,490)

(1) In conjunction with emergence from chapter 11 proceedings, the Company issued new common shares to holders of existing common shares at a conversion ratio of 0.521562. The earnings (loss) per share has been adjusted to reflect this conversion as if it had occurred on January 1, 2013.

(2) Cash flows from operating activities for the years ended December 31, 2016, 2015, 2014, and 2013, have been updated to reflect the retrospective application of the Company's adoption of ASU 2016-18.

(3) At December 31, 2016, $3.8 billion of long-term debt is included with liabilities subject to compromise on our Consolidated Balance Sheets.

(4) At December 31, 2017, costs associated with the issuance of our long-term debt, excluding the costs associated with the Credit Agreements, are presented as a direct deduction from the carrying value of the related debt liability on the Consolidated Balance Sheet.

Table of Contents

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion of the financial condition and operating results of the Company should be read in conjunction with the consolidated financial statements and related notes of the Company, which are included in this report in Item 8, and the information set forth in Risk Factors under Item 1A. Except as otherwise indicated, all amounts are expressed in U.S. dollars.

Overview

Ultra Petroleum Corp. is an independent exploration and production company focused on developing its long-life natural gas reserves in the Green River Basin of Wyoming — the Pinedale and Jonah fields and its oil reserves in the Uinta Basin in Utah. The Company operates in one industry segment, natural gas and oil exploration and development, with one geographical segment, the United States.

The Company currently conducts operations exclusively in the United States. Substantially all of its oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company's proportionate interest in such activities. The Company continues to focus on improving its drilling and production results through gaining efficiencies with the use of advanced technologies, detailed technical analysis of its properties and leveraging its experience into improved operational efficiencies. Inflation has not had, nor is it expected to have in the foreseeable future, a material impact on the Company's results of operations.

The Company currently generates its revenue, earnings and cash flow primarily from the production and sales of natural gas and condensate from its properties in southwest Wyoming with a portion of the Company's revenues coming from oil sales from its properties in the Uinta Basin in Utah. During the year ended December 31, 2017, the Company generated revenue from gas sales from wells located in the Appalachian Basin in Pennsylvania, which were sold during the fourth quarter of 2017. During 2014, the Company acquired contracts related to NGLs providing an annual election to process NGLs beginning in 2017. During 2017, the Company renegotiated its existing gas processing contracts in Wyoming. The new gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves.

The prices of oil and natural gas are critical factors to the Company's business. The prices of oil and natural gas have historically been volatile, and this volatility could be detrimental to the Company's financial performance. As a result, and from time to time, the Company tries to limit the impact of this volatility on its results by entering into swap agreements and/or fixed price forward physical delivery contracts for natural gas and oil. (See Note 7).

The average price realization for the Company's natural gas during 2017 was $2.92 per Mcf, including realized gains and losses on commodity derivatives. During the quarter ended December 31, 2017, the average price realization for the Company's natural gas was $2.86 per Mcf, including realized gains and losses on commodity derivatives. The Company's average price realization for natural gas, excluding realized gains and losses on commodity derivatives, was $2.88 per Mcf and $2.81 per Mcf for the year and the quarter ended December 31, 2017, respectively.

The average price realization for the Company's crude oil and condensate during 2017 was $48.05 per barrel. During the quarter ended December 31, 2017, the average price realization for the Company's crude oil and condensate was $53.17 per barrel.

Chapter 11 Proceedings

Voluntary Reorganization Under Chapter 11and Ability to Continue as a Going Concern

On April 29, 2016 (the "Petition Date"), the Company and its subsidiaries (collectively, "the Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). Our chapter 11 cases were jointly administered under the caption *In re Ultra Petroleum Corp.,* et al, (Case No. 16-32202 (MI). On March 14, 2017, the Bankruptcy Court confirmed the Plan and on the Effective Date, we emerged from bankruptcy.

As a result of its improved financial condition and successful emergence from chapter 11, the Company believes it has sufficient liquidity along with funds generated from ongoing operations, to fund anticipated cash requirements for operations, capital expenditures and working capital purposes. As a result, substantial doubt no longer exists regarding the Company's ability to meet its obligations as they become due within one year after the date that the financial statements are issued.

Plan Support Agreement, Rights Offering, Backstop Commitment Agreement and Exit Financing

On November 21, 2016, each of the Ultra Entities entered into a Plan Support Agreement ("PSA") with (i) holders of at least 66.67% of the principal amount of the Company's outstanding 5.750% Senior Notes due 2018 (the "2018 Senior Notes) and 6.125% Senior Notes due 2024 (the "2024 Senior Notes") and (ii) shareholders who own at least a majority of the Company's outstanding common stock or the economic interests therein (collectively, the "Plan Support Parties") and a Backstop Commitment Agreement ("BCA") with a subset thereof (collectively, the "Commitment Parties").

Plan Support Agreement: The PSA enumerated the terms and conditions pursuant to which the Ultra Entities and the Commitment Parties agreed to seek and support a joint plan of reorganization. The Plan consummated on the Effective Date was the joint plan of reorganization contemplated in the PSA.

Rights Offering: In accordance with the Plan, the BCA and the Rights Offering procedures submitted by the Company in connection with the Plan, the Company offered eligible debt and equity holders, including the Commitment Parties, the right to purchase shares of new common stock in the Company upon effectiveness of the Plan for an aggregate purchase price of $580.0 million. The Rights Offering was consummated upon the Company's emergence from bankruptcy on the Effective Date. Pursuant to the Rights Offering:

- HoldCo Noteholders were granted rights (the "HoldCo Noteholder Rights Offering") entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the "HoldCo Noteholder Rights Offering Shares"), which HoldCo Noteholder Rights Offering Shares, collectively, reflected an aggregate purchase price of $435.0 million.
- HoldCo Equityholders were granted rights (the "HoldCo Equityholder Rights Offering") entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the "HoldCo Equityholder Rights Offering Shares" and, together with the HoldCo Noteholder Rights Offering Shares, the "Rights Offering Shares"), which HoldCo Equityholder Rights Offering Shares, collectively, reflected an aggregate purchase price of $145.0 million.

Backstop Commitment Agreement: Under the BCA, the Commitment Parties agreed to purchase the HoldCo Noteholder Rights Offering Shares and the HoldCo Equityholder Rights Offering Shares, as applicable, that were not duly subscribed for pursuant to the HoldCo Noteholder Rights Offering or the HoldCo Equityholder Rights Offering, as applicable, by parties other than Commitment Parties (the "Backstop Commitment") at an implied 20% discount to the Plan Value, which is the price for the rights offering set forth in the PSA (the "Rights Offering Price"). In connection with our emergence from bankruptcy on the Effective Date, the Commitment Parties performed the Backstop Commitment as and to the extent provided for in the BCA. In addition, on the Effective Date, the Company paid the Commitment Parties a Commitment Premium equal to 6.0% of the $580.0 million committed amount. The commitment premium was paid in the form of new common stock at the Rights Offering Price.

Exit Financing: On February 8, 2017, the Debtors obtained a commitment letter (as amended, the "Commitment Letter") from Barclays Bank PLC (including any affiliates that may perform its responsibilities thereunder, "Barclays"), pursuant to which, in connection with the consummation of the Plan, Barclays agreed to provide us with secured and unsecured financing in an aggregate amount of up to $2.4 billion.

On the Effective Date, in connection with the consummation of our Plan:

- Ultra Resources entered into a Credit Agreement dated April 12, 2017 with Bank of Montreal, as administrative agent, and with the other lenders party thereto (the "RBL Credit Agreement"), providing for a revolving credit facility (the "Revolving Credit Facility") for an aggregate amount of $400.0 million;
- Ultra Resources entered into a Senior Secured Term Loan Agreement dated April 12, 2017 with Barclays Bank PLC, as administrative agent, and with the other lenders party thereto (the "Term Loan Agreement"), providing for senior secured first lien term loans for an aggregate amount of $800.0 million;
- Ultra Resources entered into an Indenture dated April 12, 2017 with Wilmington Trust, as trustee (the "Indenture"), and also issued the $700.0 million of its 6.875% unsecured senior notes due 2022 (the "2022 Notes") and $500.0 million of its 7.125% unsecured senior notes due 2025 (the "2025 Notes" and, collectively with the 2022 Notes, the "Notes"), as contemplated in a purchase agreement, dated April 7, 2017, among Ultra Resources, the guarantors party thereto, and Barclays Capital Inc.. The 2022 Notes were sold at an issue price of 100% and the 2025 Notes were sold at an issue price of 98.507%, and the issuance of the 2022 Notes and the 2025 Notes resulted in net proceeds (after deducting purchasers' discounts and commissions) to Ultra Resources of $1.185 billion.
- The principal obligations outstanding of $999.0 million under the Prepetition Credit Agreement (as defined below) and $1.46 billion under the Prepetition Senior Notes (as defined below), as well as prepetition interest and other undisputed amounts, were paid in full. The Company's obligations under the Prepetition Credit Agreement and Prepetition Senior Notes were cancelled and extinguished as provided in the Plan.
- The claims of $450.0 million related to the 2018 Senior Notes and $850.0 million related to the 2024 Senior Notes were allowed in full, each holder of a claim related to the 2018 and 2024 Notes received a distribution of common stock in the amount of the holders' applicable claim and the Company's obligations under the 2018 Notes and 2024 Notes were cancelled and extinguished as provided in the Plan.

Ultra Resources' obligations under the RBL Credit Agreement, the Term Loan Agreement, the Indenture, and the Notes are guaranteed by the Company and each of its subsidiaries (other than Ultra Resources). In addition, on the Effective Date, the Company and each of its subsidiaries (other than Ultra Resources) entered into a Guaranty and Collateral Agreement in favor of Bank of Montreal, as administrative agent, for the benefit of the secured parties under the RBL Credit Agreement and the Term Loan Agreement.

The Company's obligations under the Revolving Credit Facility and the Term Loan Agreement are secured by first priority, perfected liens and security interests on 85% of the total value of proved oil and gas properties evaluated in reserve reports delivered to the lenders under the Revolving Credit Facility, as well as a negative pledge on substantially all non-mortgaged assets of the Company and other guarantors under the Revolving Credit Facility

For further description of the emergence financing and for other information and changes to the Company's debt financing subsequent to the Effective Date, see Note 5 in this Form 10-K in our Consolidated Financial Statements.

Fresh Start Accounting

As previously disclosed, we are not required to apply fresh start accounting to our financial statements in connection with our emergence from bankruptcy because the reorganization value of our assets immediately prior to confirmation of the Plan exceeded our aggregate postpetition liabilities and allowed claims.

Liabilities Subject to Compromise

The following table reconciles the settlement of liabilities subject to compromise included in our Consolidated Balance Sheets from December 31, 2016 through December 31, 2017:

	December 31, 2017
Liabilities subject to compromise at December 31, 2016	$ 4,038,041
Debt extinguishment-cash	(2,521,493)
Debt extinguishment-non-cash	(1,339,740)
Contract settlement	(169,600)
Reclassified to accrued liabilities	(7,208)
Liabilities subject to compromise at December 31, 2017	$ —

Bankruptcy Claims Resolution Process

The claims filed against us during our chapter 11 proceedings were voluminous. In addition, claimants may file amended or modified claims in the future, which modifications or amendments may be material. The claims resolution process is on-going, and the ultimate number and amount of prepetition claims is not presently known, nor can the ultimate recovery with respect to allowed claims be presently ascertained.

As a part of the claims resolution process, we are working to resolve differences between amounts we listed in information filed during our bankruptcy proceedings and the amounts of claims filed by our creditors. We have filed, and we will continue to file, objections with the Bankruptcy Court as necessary with respect to claims we believe should be disallowed.

Costs of Reorganization

We have incurred significant costs associated with our reorganization and the chapter 11 proceedings. We expect these costs, which are being expensed as incurred, will significantly affect our results of operations. For additional information about the costs of our reorganization and chapter 11 proceedings, see "Reorganization items, net" below.

The following table summarizes the components included in Reorganization items, net in our Consolidated Statements of Operations for the years ended December 31, 2017, 2016, and 2015:

	For the Year Ended December 31,		
	2017	2016	2015
Professional fees (1)	$ (66,529)	$ (11,781)	$ —
Gains (losses) (2)	431,107	—	—
Deferred financing costs	—	(18,742)	—
Contract settlements	—	(17,350)	—
Make-whole fees (3)	(223,838)	—	—
Other (4)	167	370	—
Total Reorganization items, net	$ 140,907	$ (47,503)	$ —

(1) The year ended December 31, 2017 includes $1.1 million directly related to accrued, unpaid professional fees associated with the chapter 11 filings.

(2) Gains (losses) represent the net gain on the debt to equity exchange related to the 2018 Senior Notes and 2024 Senior Notes.

(3) Make-whole fees represent the Bankruptcy Court Order denying our objection to the make-whole claims, as further described in Note 11.

(4) Cash interest income earned for the period after the Petition Date on excess cash over normal invested capital.

Critical Accounting Policies

The discussion and analysis of the Company's financial condition and results of operations is based upon consolidated financial statements, which have been prepared in accordance with U.S. GAAP. In addition, application of GAAP requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates related to judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated. Set forth below is a discussion of the critical accounting policies used in the preparation of our financial statements which we believe involve the most complex or subjective decisions or assessments.

Oil and Gas Reserves. The reserve estimates presented herein were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance according to Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities — Oil and Gas ("FASB ASC 932") as updated in order to align the reserve calculation and disclosure requirements with those in SEC Release No. 33-8995.

The Company utilizes reliable technology such as seismic data and interpretation, wireline formation tests, geophysical logs and core data to assess its resources. However, none of these technologies have contributed to a material addition to the proved reserves in this report.

Estimates of proved crude oil and natural gas reserves significantly affect the Company's depreciation, depletion and amortization ("DD&A") expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves may result from a number of factors including lower prices, evaluation of additional operating history, mechanical problems on our wells and catastrophic events. Lower prices also make it uneconomical to drill wells or produce from fields with high operating costs.

The Company's proved reserves are a function of many assumptions, all of which could deviate materially from actual results. As a result, the estimates of proved reserves could vary over time, and could vary from actual results.

Full Cost Method of Accounting. The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Additives — Oil and Gas ("FASB ASC 932"). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded on the fair value of the asset retirement obligation when incurred. Gain or loss or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the Company's proved reserves. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement costs are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. The Company reviews its unproved leasehold costs quarterly or when management determines that events or circumstances indicate that the recorded carrying value of the unevaluated properties may not be recoverable. The fair values of unproved properties are evaluated utilizing a discounted net cash flows model based on management's assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk weighting factors. The amount of any impairment is transferred to the capitalized costs being amortized.

Write-down of Oil and Gas Properties. Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing the average of prices in effect on the first day of the month for the preceding twelve-month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company did not have any write-downs related to the full cost ceiling limitation in 2017 or 2016. During 2015, the Company recorded a $3.1 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected with ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve-month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials.

Deferred Financing Costs. At December 31, 2017, the Company follows ASU No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* and includes the costs for issuing debt, including issuance discounts, except those related to the revolving credit facility, as a direct deduction from the carrying amount of the related debt liability. Costs related to the issuance of the revolving credit facility are recorded as an asset in the Consolidated Balance Sheets.

Asset Retirement Obligation. The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. FASB ASC Topic 410, Asset Retirement and Environmental Obligations ("FASB ASC 410") requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements; the credit-adjusted, risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company 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 passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A.

Entitlements Method of Accounting for Oil and Natural Gas Sales. The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices and under multi-year contracts that provide for a fixed price of oil and natural gas. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances.

Valuation of Deferred Tax Assets. The Company uses the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax basis (temporary differences).

To assess the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment.

The Company has recorded a valuation allowance against all of its deferred tax assets as of December 31, 2017. Some or all of this valuation allowance may be reversed in future periods against future income.

Derivative Instruments and Hedging Activities. The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations as an unrealized gain or loss on commodity derivatives.

Fair Value Measurements. The Company follows FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"). Under FASB ASC 820, fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at measurement date and establishes a three-level hierarchy for measuring fair value. The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs). See Note 8 for additional information.

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that the counterparty is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

	Level 1	Level 2	Level 3	Total
Assets:				
Current derivative asset	$ —	$ 16,865	$ —	$ 16,865

Legal, Environmental and Other Contingencies. A provision for legal, environmental and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingencies and periodically determines when the Company should record losses for these items based on information available to the Company. Contingent gains arise if the outcome of future events may result in a possible gain or benefit to the Company and are recorded when the gain is realized.

Share-Based Payment Arrangements. The Company follows FASB ASC Topic 718, Compensation — Stock Compensation ("FASB ASC 718") which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values. Share-based compensation expense recognized under FASB ASC 718 for the years ended December 31, 2017, 2016 and 2015 was $40.0 million, $5.6 million and $4.1 million, respectively. See Note 6 for additional information.

Conversion of Barrels of Oil to Mcfe of Gas. The Company converts barrels of oil and other liquid hydrocarbons to Mcfe at a ratio of one barrel of oil or liquids to six Mcfe. This conversion ratio, which is typically used in the oil and gas industry, represents the approximate energy equivalent of a barrel of oil or other liquids to an Mcf of natural gas. The sales price of one barrel of oil or liquids has been much higher than the sales price of six Mcf of natural gas over the last several years, so a six to one conversion ratio does not represent the economic equivalency of six Mcf of natural gas to a barrel of oil or other liquids.

Recent accounting pronouncements.

Statement of Cash Flows: In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* ("ASU No. 2016-18"). The guidance requires that an explanation is included in the cash flow statement of the change in the total of (1) cash, (2) cash equivalents, and (3) restricted cash or restricted cash equivalents. The ASU also clarifies that transfers between cash, cash equivalents and restricted cash or restricted cash equivalents should not be reported as cash flow activities and requires the nature of the restrictions on cash, cash equivalents, and restricted cash or restricted cash equivalents to be disclosed. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. We early adopted ASU 2016-18 at December 31, 2017 and disclosure revisions have been made for the years presented on the Consolidated Statements of Cash Flows. All prior periods have been adjusted to confirm, which resulted in a (decrease)/increase in cash flows from operating activities of approximately ($1.9) million, $3.5 million and ($0.2) million for the years ended December 31, 2017, 2016 and 2015, respectively. See the following table for a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the same amounts shown in the Consolidated Statements of Cash Flows.

Current Presentation	**December 31, 2017**	**December 31, 2016**	**December31, 2015**
Cash and Cash Equivalents	$ 16,631	$ 401,478	$ 4,143
Restricted Cash	1,638	3,571	115
Total cash, cash equivalents, and restricted cash	$ 18,269	$ 405,049	$ 4,258

Statement of Cash Flows: In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)* ("ASU No. 2016-15"). The guidance requires that debt prepayment or debt extinguishment costs, including third-party costs, premiums paid, and other fees paid to lenders, be classified as cash outflows for financing activities. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. We early adopted ASU 2016-15 at December 31, 2017. The guidance was applied retrospectively as required by the standard. For the year ended December 31, 2017, the material impact to the Consolidated Statement of Cash Flows was the reclassification of costs related to the extinguishment of long-term debt from cash flows provided by operating activities to cash flows used in financing activities totaling $223.8 million. There was no material impact to the Consolidated Statement of Cash Flows for the years ended December 31, 2016 and 2015.

Leases: In February 2016, the FASB issued ASU 2016-02, *Leases* ("ASU No. 2016-02"). The guidance requires that lessees will be required to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months. The ASU will also require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative information. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 with earlier application permitted. The Company is still evaluating the impact of ASU No. 2016-02 on its financial position and results of operations.

Stock Compensation: In May 2017, the FASB issued ASU 2017-09, *Compensation-Stock Compensation (Topic 718)* ("ÁSU No. 2017-09"), which is intended to clarify and reduce diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. The Company does not expect the adoption of ASU No. 2017-09 to have a material impact on its consolidated financial statements.

Derivatives: In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815)* ("ASU No. 2017-12"), which makes significant changes to the current hedge accounting rules. The new guidance impacts the designation of hedging relationships; measurement of hedging relationships; presentation of the effects of hedging relationships; assessment of hedge effectiveness; and disclosures. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. The Company does not expect the adoption of ASU No. 2017-12 to have a material impact on its consolidated financial statements.

Revenues from Contracts with Customers: In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) and in 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), and ASU 2016-10, Revenues from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services.

We have evaluated the provisions of ASU 2014-09 and assessed the impact it may have on our financial positi on and results of operations. As part of our assessment work, we have done the following:

- We have completed training of the new ASU's revenue recognition model, dedicated resources to its implementation, and initiated contract review and documentation; including analyzing the standard's impact on our contract portfolio, comparing historical accounting policies and practices to the requirements of the new standard, and identifying differences from applying the requirements of the new standards to our contracts.
- We have evaluated each revenue stream, including sales of oil, natural gas, and other revenues, noting no significant changes to revenue recognition under the new standard.
- We had previously elected to utilize the entitlements method, which will no longer be applicable under ASU 2014-09. We do not anticipate the change from the entitlements method to have a material impact on our financial statements.
- We evaluated our product sales contracts in order to determine if there were remaining performance obligations. We have determined that our product sales are primarily short-term in nature with contract periods of one year or less. We have evaluated product sales contracts with terms greater than one year and anticipate using the practical expedient in ASC 606-10-50-14(a) which will not require disclosure of the transaction price allocated to remaining performance obligations.
- We have evaluated our product sales contracts and do not anticipate them to give rise to contract assets or liabilities.
- We have evaluated the expanded disclosure requirements under the new standard and reviewed our processes, systems, and internal controls over financial reporting to ensure the appropriate information will be available for these disclosures. We do not anticipate any issues in providing the appropriate information to be available for the disclosures.

The Company was required to adopt the new standards in the first quarter of 2018 using one of two application methods: retrospectively to each prior reporting period presented (full retrospective method), or retrospectively with the cumulative effect of initially applying the guidance recognized at the date of initial application (the modified retrospective method). The Company adopted the standard as of January 1, 2018 using the modified retrospective method. The Company is currently estimating the impact to beginning retained earnings to be immaterial to the overall consolidated financial statements based on implementation through the modified retrospective approach.

Results of Operations — Year Ended December 31, 2017 vs. Year Ended December 31, 2016

	For the year ended December 31,		
	2017	2016	% change
	(Amounts in thousands, except per unit data)		
Production, Commodity Prices and Revenues:			
Production:			
Natural gas (Mcf)	260,009	264,278	-2%
Crude oil and condensate (Bbls)	2,775	2,912	-5%
Total production (Mcfe)	276,659	281,748	-2%
Commodity Prices:			
Natural gas ($/Mcf, incl realized hedges)	$ 2.92	$ 2.31	27%
Natural gas ($/Mcf, excluding hedges)	$ 2.88	$ 2.31	25%
Crude oil and condensate ($/Bbl, incl realized hedges)	$ 48.05	$ 38.24	26%
Crude oil and condensate ($/Bbl, excluding hedges)	$ 48.05	$ 38.24	26%
Revenues:			
Natural gas sales	$ 748,682	$ 609,756	23%
Oil sales	$ 133,368	$ 111,335	20%
Other revenues	$ 9,823	$ —	n/a
Total operating revenues	$ 891,873	$ 721,091	24%
Derivatives:			
Realized gain on commodity derivatives	$ 11,446	$ —	n/a
Unrealized gain on commodity derivatives	$ 16,966	$ —	n/a
Total gain on commodity derivatives	$ 28,412	$ —	n/a
Operating Costs and Expenses:			
Lease operating expenses	$ 92,326	$ 89,134	4%
Facility lease expense	$ 21,749	$ 20,686	5%
Production taxes	$ 91,067	$ 69,737	31%
Gathering fees	$ 86,953	$ 86,809	0%
Transportation charges	$ —	$ 20,049	-100%
Depletion, depreciation and amortization	$ 161,945	$ 125,121	29%
General and administrative expenses	$ 39,548	$ 9,179	331%
Per Unit Costs and Expenses ($/Mcfe):			
Lease operating expenses	$ 0.33	$ 0.32	3%
Facility lease expense	$ 0.08	$ 0.07	14%
Production taxes	$ 0.33	$ 0.25	32%
Gathering fees	$ 0.31	$ 0.31	0%
Transportation charges	$ —	$ 0.07	-100%
Depletion, depreciation and amortization	$ 0.59	$ 0.44	34%
General and administrative expenses	$ 0.14	$ 0.03	367%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2017, production decreased on a gas equivalent basis to 276.7 Bcfe from 281.7 Bcfe for the same period in 2016. The decrease is primarily attributable to decreased capital investment during the year ended December 31, 2016.

Commodity prices — natural gas. Realized natural gas prices, including realized gains and losses on commodity derivatives, increased to $2.92 per Mcf during the year ended December 31, 2017 as compared to $2.31 per Mcf during 2016. The Company has open natural gas price commodity derivative contracts as of December 31, 2017, see Note 7 for additional details. During the year ended December 31, 2017, the Company's average price for natural gas, excluding realized gains and losses on commodity derivatives was $2.88 per Mcf as compared to $2.31 per Mcf for the same period in 2016.

Commodity prices — oil. During the year ended December 31, 2017, the average price realization for the Company's oil was $48.05 per barrel compared with $38.24 per barrel during 2016. The Company did not have any open derivative contracts for oil production during 2017 or 2016.

Revenues. The increase in average oil and natural gas prices partially offset by decreased total production resulted in revenues increasing to $891.9 million for the for the year ended December 31, 2017 as compared to $721.1 million in 2016.

Operating Costs and Expenses:

Lease Operating Expense. Lease operating expenses ("LOE") increased to $92.3 million for the year ended December 31, 2017 compared to $89.1 million during the same period in 2016 largely related to the increase in producing well counts. On a unit of production basis, LOE costs increased to $0.33 per Mcfe at December 31, 2017 compared to $0.32 per Mcfe at December 31, 2016.

Facility Lease Expense. During December 2012, the Company sold a system of liquids gathering pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming. The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the Pinedale LGS (the "Pinedale Lease Agreement"). The Pinedale Lease Agreement provides for an initial term of 15 years, and annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease. For the year ended December 31, 2017, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $21.7 million, or $0.08 per Mcfe compared with $20.7 million, or $0.07 per Mcfe in 2016.

Production Taxes. During the year ended December 31, 2017, production taxes were $91.1 million compared to $69.7 million during the same period in 2016, or $0.33 per Mcfe in 2017, compared to $0.25 per Mcfe in 2016. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming and Utah after certain deductions and were 10.2% of revenues for the year ended 2017 and 9.7% for the same period in 2016. The increase in production taxes is primarily attributable to increased oil and natural gas prices during the year December 31, 2017 as compared to the same period in 2016.

Gathering Fees. Gathering fees increased slightly to $87.0 million for the year ended December 31, 2017 compared to $86.8 million during the same period in 2016. On a per unit basis, gathering fees remained flat at $0.31 per Mcfe for the year ended December 31, 2017 and 2016.

Transportation Charges. As a result of the termination of the Rockies Express Pipeline ("Rockies Express") contract during the first quarter of 2016, there were no material transportation charges for the year ended December 31, 2017. Transportation charges were $20.0 million for the year ended December 31, 2016.

Depletion, Depreciation and Amortization. DD&A expenses increased to $161.9 million during the year ended December 31, 2017 from $125.1 million for the same period in 2016, attributable to the addition of proved undeveloped properties (PUDs) as a result of emergence from chapter 11 proceedings. On a unit of production basis, DD&A increased to $0.59 per Mcfe at December 31, 2017 from $0.44 per Mcfe at December 31, 2016.

General and Administrative Expenses. General and administrative expenses increased to $39.5 million for the year ended December 31, 2017 compared to $9.2 million for the same period in 2016. The increase in general and administrative expenses is primarily attributable to the non-cash stock incentive compensation expense that was incurred as part of the 2017 Stock Incentive Plan, in which tranche one became fully vested on the Effective Date. On a per unit basis, general and administrative expenses increased to $0.14 per Mcfe at December 31, 2017 from $0.03 per Mcfe at December 31, 2016.

Other Income and Expenses:

Interest Expense. Interest expense increased to $361.4 million during the year ended December 31, 2017 compared to $66.6 million during the same period in 2016. The increase in interest expense is comprised of $85.8 million of accrued postpetition interest for the period beginning April 29, 2016 through April 12, 2017, $100.4 million of interest expense incurred on the Revolving Credit Facility, Term Loan Facility, and the Notes (see Note 5 for additional details), and $175.2 million for postpetition interest, related to the Bankruptcy Court order denying our objection to postpetition interest claims, at the default rate for the period beginning April 29, 2016 through April 12, 2017, as described in Note 11.

Restructuring Expenses. During the year ended December 31, 2016, the Company incurred $7.2 million in costs and fees in connection with its efforts to restructure its debt prior to filing the chapter 11 petitions.

Contract Settlement. Contract settlement expense decreased to $52.7 million for the year ended December 31, 2017 compared to $131.1 million for the year ended December 31, 2016. The decrease relates to the contract settlement of $57.0 million reached with Sempra Rockies Marketing, LLC during the year ended December 31, 2017 as compared to the contract settlement of $150.0 million reached with Rockies Express Pipeline LLC during the year ended December 31, 2016.

Deferred Gain on Sale of Liquids Gathering System. During the years ended December 31, 2017 and 2016, the Company recognized $10.6 million in deferred gain on sale of the liquids gathering system relating to the sale of a system of pipelines and central gathering facilities and certain associated real property rights in the Pinedale Anticline in Wyoming during December 2012.

Commodity Derivatives:

Gain on Commodity Derivatives. During the year ended December 31, 2017, the Company recognized a gain of $28.4 million related to commodity derivatives. Of this total, the Company recognized $11.4 million related to realized gain during the year ended December 31, 2017. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts. This gain or loss on commodity derivatives also includes a $17.0 million unrealized gain on commodity derivatives at December 31, 2017. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments over the remaining term of the contract. The Company did not have any open commodity derivatives at December 31, 2016.

Reorganization Items:

Reorganization Items, Net. Reorganization items, net increased to income of $140.9 million for the year ended December 31, 2017 compared to expense of $47.5 million for the same period in 2016. The increase is due to the emergence from chapter 11 proceedings during the year ended December 31, 2017 and is primarily comprised of expenses of $66.4 million in professional fees, settlements, and interest income associated with the Company's chapter 11 cases and of $223.8 million related to the Bankruptcy Court order denying our objection to the make-whole claims offset by a gain of $431.1 million, which primarily represents the gain on the debt for equity exchange related to the prepetition 2018 and 2024 Senior Notes. No cash tax is expected to be recognized as the result of this gain.

Income from Continuing Operations:

Pretax Income. The Company recognized income before income taxes of $163.8 million for the year ended December 31, 2017 compared with income of $55.5 million for the same period in 2016. The increase in earnings is primarily attributable to increased revenues due to increases in the average oil and natural gas prices and the net effect of reorganization items, partially offset by an increase in interest expense, DD&A, and general and administrative expense during the year ended December 31, 2017.

Income Taxes. The Company has recorded a $13.3 million tax benefit related to expected U.S. cash tax refunds. The Company has recorded a valuation allowance against all of its net deferred tax asset balance as of December 31, 2017. Some or all of this valuation allowance may be reversed in future periods against future income.

Net Income. For the year ended December 31, 2017, the Company recognized net income of $177.1 million or $1.08 per diluted share as compared with net income of $56.2 million or $0.70 per diluted share for the same period in 2016. The increase in earnings is primarily attributable to increased revenues due to increases in the average oil and natural gas prices and the net effect of reorganization items, partially offset by an increase in interest expense, DD&A, and general and administrative expense during the year ended December 31, 2017.

Table of Contents

Results of Operations — Year Ended December 31, 2016 vs. Year Ended December 31, 2015

	For the year ended December 31,		
	2016	2015	% change
	(Amounts in thousands, except per unit data)		
Production, Commodity Prices and Revenues:			
Production:			
Natural gas (Mcf)	264,278	268,954	-2%
Crude oil and condensate (Bbls)	2,912	3,533	-18%
Total production (Mcfe)	281,748	290,149	-3%
Commodity Prices:			
Natural gas ($/Mcf, incl realized hedges)	$ 2.31	$ 3.14	-26%
Natural gas ($/Mcf, excluding hedges)	$ 2.31	$ 2.59	-11%
Crude oil and condensate ($/Bbl, incl realized hedges)	$ 38.24	$ 40.31	-5%
Crude oil and condensate ($/Bbl, excluding hedges)	$ 38.24	$ 40.31	-5%
Revenues:			
Natural gas sales	$ 609,756	$ 696,730	-12%
Oil sales	$ 111,335	$ 142,381	-22%
Total operating revenues	$ 721,091	$ 839,111	-14%
Derivatives:			
Realized gain on commodity derivatives	$ —	$ 146,801	n/a
Unrealized loss on commodity derivatives	$ —	$ (104,190)	n/a
Total gain on commodity derivatives	$ —	$ 42,611	n/a
Operating Costs and Expenses:			
Lease operating expenses	$ 89,134	$ 106,906	-17%
Facility lease expense	$ 20,686	$ 20,647	0%
Production taxes	$ 69,737	$ 72,774	-4%
Gathering fees	$ 86,809	$ 87,904	-1%
Transportation charges	$ 20,049	$ 83,803	-76%
Depletion, depreciation and amortization	$ 125,121	$ 401,200	-69%
Ceiling test and other impairments	$ —	$ 3,144,899	-100%
General and administrative expenses	$ 9,179	$ 7,387	24%
Per Unit Costs and Expenses ($/Mcfe):			
Lease operating expenses	$ 0.32	$ 0.37	-14%
Facility lease expense	$ 0.07	$ 0.07	0%
Production taxes	$ 0.25	$ 0.25	0%
Gathering fees	$ 0.31	$ 0.30	3%
Transportation charges	$ 0.07	$ 0.29	-76%
Depletion, depreciation and amortization	$ 0.44	$ 1.38	-68%
General and administrative expenses	$ 0.03	$ 0.03	0%

Production, Commodity Prices and Revenues:

Production. During the year ended December 31, 2016, production decreased on a gas equivalent basis to 281.7 Bcfe from 290.1 Bcfe for the same period in 2015. The decrease is primarily attributable to decreased capital investment during the year ended December 31, 2016.

Commodity prices — natural gas. Realized natural gas prices decreased to $2.31 per Mcf during the year ended December 31, 2016 as compared to $2.59 per Mcf during 2015. The Company did not have any open derivative contracts for natural gas production during 2016. During the year ended December 31, 2015, the Company's average price for natural gas was $3.14 per Mcf, including realized gains and losses on commodity derivatives.

Commodity prices — oil. During the year ended December 31, 2016, the average price realization for the Company's oil was $38.24 per barrel compared with $40.31 per barrel during 2015. The Company did not have any open derivative contracts for oil production during 2016 or 2015.

Revenues. The decrease in average oil and natural gas prices and decreased total production resulted in revenues decreasing to $721.1 million for the year ended December 31, 2016 as compared to $839.1 million in 2015.

Operating Costs and Expenses:

Lease Operating Expense. LOE decreased to $89.1 million for the year ended December 31, 2016 compared to $106.9 million during the same period in 2015 largely related to lower costs due to improved efficiencies. On a unit of production basis, LOE costs decreased to $0.32 per Mcfe at December 31, 2016 compared to $0.37 per Mcfe at December 31, 2015.

Facility Lease Expense. During December 2012, the Company sold the Pinedale LGS and certain associated real property rights in the Pinedale Anticline in Wyoming. The Company entered into a long-term, triple net lease agreement with the buyer relating to the use of the Pinedale LGS (the "Pinedale Lease Agreement"). The Pinedale Lease Agreement provides for an initial term of 15 years, and annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease. For the year ended December 31, 2016, the Company recognized operating lease expense associated with the Pinedale Lease Agreement of $20.7 million, or $0.07 per Mcfe compared with $20.6 million, or $0.07 per Mcfe in 2015.

Production Taxes. During the year ended December 31, 2016, production taxes were $69.7 million compared to $72.8 million during the same period in 2015, or $0.25 per Mcfe in 2016 and 2015. Production taxes are primarily calculated based on a percentage of revenue from production in Wyoming and Utah after certain deductions and were 9.7% of revenues for the year ended 2016 and 8.7% for the same period in 2015. The decrease in production taxes is primarily attributable to decreased oil and natural gas prices during the year December 31, 2016 as compared to the same period in 2015.

Gathering Fees. Gathering fees decreased slightly to $86.8 million for the year ended December 31, 2016 compared to $87.9 million during the same period in 2015. On a per unit basis, gathering fees increased slightly to $0.31 per Mcfe for the year ended December 31, 2016 as compared to $0.30 per Mcfe for the year ended December 31, 2015.

Transportation Charges. Transportation charges decreased to $20.0 million for the year ended December 31, 2016 as compared to $83.8 million for the same period in 2015 primarily as a result of the termination of the Rockies Express contract during the first quarter of 2016.

Depletion, Depreciation and Amortization. DD&A expenses decreased to $125.1 million during the year ended December 31, 2016 from $401.2 million for the same period in 2015, attributable to a decreased depletion rate on a unit of production basis as a result of the ceiling test impairment during the fourth quarter of 2015. On a unit of production basis, DD&A decreased to $0.44 per Mcfe at December 31, 2016 from $1.38 per Mcfe at December 31, 2015.

Ceiling Test Write-Down. The Company recorded a $3.1 billion non-cash write-down of the carrying value of its proved oil and natural gas properties for the year ended December 31, 2015 as a result of ceiling test limitations, which is reflected as ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve-month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials. The write-down reduced earnings in the period and will result in lower a DD&A rate in future periods. The Company did not have any write-downs related to the full cost ceiling limitation during the prior year ended December 31, 2016.

General and Administrative Expenses. General and administrative expenses increased to $9.2 million for the year ended December 31, 2016 compared to $7.4 million for the same period in 2015. The increase in general and administrative expenses is primarily attributable to reversal of certain incentive compensation expense during the year ended December 31, 2015. On a per unit basis, general and administrative expenses remained flat at $0.03 per Mcfe for the year ended December 31, 2016 and 2015.

Other Income and Expenses:

Interest Expense. Interest expense decreased to $66.6 million during the year ended December 31, 2016 compared to $171.9 million during the same period in 2015. No interest was recognized during the year ended December 31, 2016 subsequent to the petition date of April 29, 2016.

Litigation Expense During the year ended December 31, 2015, the Company recognized litigation expenses of $4.4 million related to the resolution of litigation matters.

Deferred Gain on Sale of Liquids Gathering System. During the years ended December 31, 2016 and 2015, the Company recognized $10.6 million in deferred gain on sale of the liquids gathering system relating to the sale of a system of pipelines and central gathering facilities and certain associated real property rights in the Pinedale Anticline in Wyoming during December 2012.

Commodity Derivatives:

Gain (Loss) on Commodity Derivatives. The Company did not have any open commodity derivative contracts as of December 31, 2016. During the year ended December 31, 2015, the Company recognized a gain of $42.6 million related to commodity derivatives. Of this total, the Company recognized $146.8 million related to realized gain during the year ended December 31, 2015. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under the Company's derivative contracts. This gain or loss on commodity derivatives also includes a $104.2 million unrealized loss on commodity derivatives at December 31, 2015. The unrealized gain or loss on commodity derivatives represents the change in the fair value of these derivative instruments over the remaining term of the contract.

Reorganization Items:

Reorganization Items, Net. Reorganization items, net represent expense of $47.5 million for the year ended December 31, 2016 include the contract settlement of $17.4 million related to a settlement reached with Big West Oil, LLC. Reorganization items, net also includes professional fees and interest income of $11.4 million and a non-cash charge to write-off all unamortized debt issuance costs totaling $18.7 million related to the Prepetition Credit Agreement, the Prepetition Senior Notes, the 2018 Notes, and the 2024 Notes issued by the Company.

Income (Loss) from Continuing Operations:

Pretax Income (Loss). The Company recognized income before taxes of $55.5 million for the year ended December 31, 2016 compared with a loss of $3.2 billion for the same period in 2015. The increase in earnings is primarily related to the non-cash ceiling test impairment incurred during 2015 and decreased DD&A, reduced interest expense, and reduced transportation charges during the year ended December 31, 2016; partially offset by costs associated with the reorganization and decreased revenues as a result of lower oil and natural gas prices for the year ended December 31, 2016 as compared to the same period in 2015.

Income Taxes. The Company has recorded a valuation allowance against substantially all of its net deferred tax asset balance as of December 31, 2016. Some or all of this valuation allowance may be reversed in future periods against future income.

Net Income (Loss). For the year ended December 31, 2016, the Company recognized a net income of $56.2 million or $0.70 per diluted share as compared with a net loss of $3.2 billion or ($40.14) per diluted share for the same period in 2015. The increase in earnings is primarily related to the non-cash ceiling test impairment incurred during 2015 and decreased DD&A, reduced interest expense, and transportation charges during the year ended December 31, 2016; partially offset by costs associated with the reorganization and decreased revenues as a result of lower oil and natural gas prices for the year ended December 31, 2016 as compared to the same period in 2015.

LIQUIDITY AND CAPITAL RESOURCES

Overview. During the year ended December 31, 2017, we funded our operations primarily through cash flows from operating activities and borrowings under the RBL Credit Agreement and our other emergence financing agreements as further described in 'Emergence Financing and Transactions' below. At December 31, 2017, the Company reported a cash position of $16.6 million compared to $401.5 million at December 31, 2016. At December 31, 2017, the Company did not have any outstanding borrowings and had $425.0 million of available borrowing capacity under the RBL Credit Agreement. In addition, the Company had $2.2 billion outstanding in term loans and senior notes.

Given the current level of volatility in the market and unpredictability of certain costs that could potentially arise in our operations, the Company's liquidity needs could be significantly higher than the Company currently anticipates. The Company's ability to maintain adequate liquidity depends on the prevailing market prices for oil and natural gas, the successful operation of the business, and appropriate management of operating expenses and capital spending. The Company's anticipated liquidity needs are highly sensitive to changes in each of these and other factors.

Emergence Financing and Transactions. Upon our emergence from chapter 11 proceedings, the following transactions occurred which significantly affected the Company's liquidity:

- Ultra Resources entered into and issued, as applicable, secured and unsecured financing in an aggregate amount of up to $2.4 billion, consisting of (i) the Term Loan Agreement (a seven-year secured first lien term loan credit facility in an aggregate amount of $800.0 million), (ii) the RBL Credit Agreement (a senior secured first lien revolving credit facility in an aggregate amount of $400.0 million), and (iii) the unsecured Senior Notes (2022 Notes in an aggregate principle amount of $700.0 million and 2025 Notes in an aggregate principal amount of $500.0 million);

- Debt repayment, cancellation and extinguishment of the $1.0 billion unsecured revolving credit facility between Ultra Resources and JPMorgan Chase Bank, N.A. (the "Prepetition Credit Agreement") and $1.46 billion senior unsecured private placement notes issued by Ultra Resources (the "Prepetition Senior Notes"), including principal, prepetition interest, and certain other interest, fees, and expenses; and
- Completion of the $580.0 million Rights Offering and payment of applicable Backstop Commitment fee.

Capital Expenditures. For the year ended December 31, 2017, total capital expenditures were $557.0 million. During this period, the Company participated in 210 gross (172.1 net) wells in Wyoming that were drilled to total depth and cased. No wells were drilled in Utah or Pennsylvania during 2017.

2018 Capital Investment Plan. For 2018, our capital expenditures are expected to be approximately $400.0 million. We expect to fund these capital expenditures through cash flows from operations, borrowings under the RBL Credit Agreement, and cash on hand. We expect to allocate nearly all of the budget to development activities in our Pinedale field.

Common stock-NASDAQ Listing. In connection with its emergence from chapter 11 proceedings, the Company issued 194,991,656 shares of its new common stock. All of the Company's existing common stock that had been trading under the ticker symbol "UPLMQ" was cancelled and the existing stockholders received new common stock as set forth in the Plan. All of the allowed claims attributable to the prepetition high yield bonds issued by the Company were converted into new common stock as set forth in the Plan. The shares related to the $580.0 million equity rights offering were issued and the fee payable to the commitment parties under the Backstop Commitment Agreement was paid in new common stock as set forth in the Plan. The newly-issued common stock began trading on The NASDAQ Global Select Market on April 13, 2017 under the ticker symbol "UPL".

Ultra Resources, Inc.

Credit Agreement. On April 12, 2017, Ultra Resources, Inc. ("Ultra Resources"), as the borrower, entered into a Credit Agreement with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent, and with the other lenders party thereto from time to time (as amended, the "RBL Credit Agreement"), providing for a revolving credit facility (the "Revolving Credit Facility,") for an aggregate amount of $400.0 million and an initial borrowing base of $1.2 billion (which limits the aggregate amount of first lien debt under the Revolving Credit Facility and the Term Loan Facility (defined below)). On September 19, 2017, the Bank of Montreal, as administrative agent, and the other lenders party thereto, approved an increase in the borrowing base under the RBL Credit Agreement from $1.2 billion to $1.4 billion as requested by the Company, which included an increase in the commitments under the RBL Credit Agreement to an aggregate amount of $425.0 million. At December 31, 2017, Ultra Resources did not have any outstanding borrowings under the RBL Credit Agreement, had total commitments under the RBL Credit Agreement of $425.0 million, and a borrowing base of $1.4 billion. There are no scheduled borrowing base redeterminations until April 1, 2018.

The Revolving Credit Facility has capacity for Ultra Resources to increase the commitments subject to certain conditions, and had $50.0 million of the commitments available for the issuance of letters of credit. During the quarter ended December 31, 2017, the Company utilized $34.5 million of the commitments available for the issuance of a letter of credit associated with the Pennsylvania Asset Sale. The Revolving Credit Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus an applicable margin that varies from 250 to 350 basis points or (b) the base rate plus an applicable margin that varies from 150 to 250 basis points. The interest rate remained the same for the Revolving Credit Facility subsequent to approved commitments increase noted above. The Revolving Credit Facility loans mature on January 12, 2022.

The RBL Credit Agreement requires Ultra Resources to maintain (i) an interest coverage ratio of 2.50 to 1.00; (ii) a current ratio, including the unused portion of the Revolving Credit Facility, of 1.00 to 1.00; (iii) a consolidated net leverage ratio of (A) 4.25 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2017 and (B) 4.00 to 1.00, as of the last day of any fiscal quarter thereafter; and (iv) after the Company has obtained investment grade rating an asset coverage ratio of 1.50 to 1.00. At December 31, 2017, Ultra Resources was in compliance with all of its debt covenants under the RBL Credit Agreement.

Ultra Resources is required to pay a commitment fee on the average daily unused portion of the Revolving Credit Facility, which varies based upon a borrowing base utilization grid. Ultra Resources is also required to pay customary letter of credit and fronting fees.

The RBL Credit Agreement also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments, hedging requirements and other customary covenants.

The RBL Credit Agreement contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the RBL Credit Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Credit Agreement and any outstanding unfunded commitments may be terminated.

Term Loan. On April 12, 2017, Ultra Resources, as borrower, entered into a Senior Secured Term Loan Agreement with the Company and UP Energy Corporation, as parent guarantors, Barclays Bank PLC, as administrative agent, and the other lenders party thereto (the "Term Loan Agreement"), providing for senior secured first lien term loans for an aggregate amount of $800.0 million consisting of an initial term loan in the amount of $600.0 million and an incremental term loan in the amount of $200.0 million to be drawn immediately after the funding of the initial term loan. On September 29, 2017, the Company closed an incremental senior secured term loan offering of $175.0 million, increasing total borrowings under the Term Loan Agreement to $975.0 million (the "Term Loan Facility"). As part of the Term Loan Agreement, Ultra Resources agreed to pay an original issue discount equal to one percent of the principal amount, which is included in the deferred financing costs noted above. The Term Loan Agreement has capacity to increase the commitments subject to certain conditions. At December 31, 2017, Ultra Resources had $975.0 million in outstanding borrowings under the Term Loan Facility.

The Term Loan Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus 300 basis points or (b) the base rate plus 200 basis points. The Term Loan Facility amortizes in equal quarterly installments in aggregate annual amounts equal to 0.25% of the aggregate principal amount beginning on June 30, 2019. The Term Loan Facility matures seven years after the Effective Date.

The Term Loan Facility is subject to mandatory prepayments and customary reinvestment rights. The mandatory prepayments include, without limitation, a prepayment requirement with the total net proceeds from certain asset sales and net proceeds on insurance received on account of any loss of Ultra Resources' property or assets, in each case subject to certain exceptions. In addition, subject to certain exceptions, there is a prepayment requirement if the asset coverage ratio is less than 2.0 to 1.0. To the extent any mandatory prepayments are required, prepayments are applied to prepay the Term Loan Facility.

The Term Loan Agreement also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants. At December 31, 2017, Ultra Resources was in compliance with all of its debt covenants under the Term Loan Facility.

The Term Loan Agreement contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the Term Loan Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Term Loan Agreement.

Senior Notes. On April 12, 2017, the Company issued $700.0 million of its 6.875% senior notes due 2022 (the "2022 Notes") and $500.0 million of its 7.125% senior notes due 2025 (the "2025 Notes," and together with the 2022 Notes, the "Notes") and entered into an Indenture, dated April 12, 2017 (the "Indenture"), among Ultra Resources, as issuer, the Company and its subsidiaries, as guarantors. The Notes are treated as a single class of securities under the Indenture.

The Notes have not been registered under the Securities Act of 1933, as amended (the "Securities Act") or any state securities laws, and unless so registered, the securities may not be offered or sold in the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. The Notes may be resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act or to non-U.S. persons pursuant to Regulation S under the Securities Act.

The 2022 Notes will mature on April 15, 2022. The interest payment dates for the 2022 Notes are April 15 and October 15 of each year. The 2025 Notes will mature on April 15, 2025. The interest payment dates for the 2025 Notes are April 15 and October 15 of each year. Interest will be paid on the Notes from the issue date until maturity.

Prior to April 15, 2019, Ultra Resources may, at any time or from time to time, redeem in the aggregate up to 35% of the aggregate principal amount of the 2022 Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 106.875% of the principal amount of the 2022 Notes, plus accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the original principal amount of the 2022 Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before April 15, 2019, Ultra Resources may redeem all or a part of the 2022 Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. In addition, on or after April 15, 2019, Ultra Resources may redeem all or a part of the 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.438% for the twelve-month period beginning on April 15, 2019, 101.719% for the twelve-month period beginning April 15, 2020, and 100.000% for the twelve-month period beginning April 15, 2021 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Prior to April 15, 2020, Ultra Resources may, at any time or from time to time, redeem in the aggregate up to 35% of the aggregate principal amount of the 2025 Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 107.125% of the principal amount of the 2025 Notes, plus accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the original principal amount of the 2025 Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before April 15, 2020, Ultra Resources may redeem all or a part of the 2025 Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. In addition, on or after April 15, 2019, Ultra Resources may redeem all or a part of the 2025 Notes at redemption prices (expressed as percentages of principal amount) equal to 105.344% for the twelve-month period beginning on April 15, 2020, 103.563% for the twelve-month period beginning April 15, 2021, 101.781% for the twelve-month period beginning April 15, 2022, and 100.000% for the twelve-month period beginning April 15, 2023 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2025 Notes.

If Ultra Resources experiences certain change of control triggering events set forth in the Indenture, each holder of the Notes may require Ultra Resources to repurchase all or a portion of its Notes for cash at a price equal to 101% of the aggregate principal amount of such Notes, plus any accrued but unpaid interest to the date of repurchase.

The Indenture contains customary covenants that restrict the ability of Ultra Resources and the guarantors and certain of its subsidiaries to: (i) sell assets and subsidiary equity; (ii) incur indebtedness; (iii) create or incur certain liens; (iv) enter into affiliate agreements; (v) enter into agreements that restrict distribution from certain restricted subsidiaries and the consummation of mergers and consolidations; (vi) consolidate, merge or transfer all or substantially all of the assets of the Company or any Restricted Subsidiary (as defined in the Indenture); and (vii) create unrestricted subsidiaries. The covenants in the Indenture are subject to important exceptions and qualifications. Subject to conditions, the Indenture provides that the Company and its subsidiaries will no longer be subject to certain covenants when the Notes receive investment grade ratings from any two of S&P Global Ratings, Moody's Investors Service, Inc., and Fitch Ratings, Inc. At December 31, 2017, Ultra Resources was in compliance with all of its debt covenants under the Notes.

The Indenture contains customary events of default (each, an "Event of Default"). Unless otherwise noted in the Indenture, upon a continuing Event of Default, the trustee under the Indenture ("the Trustee"), by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Notes, by notice to the Company and the Trustee, may, declare the Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Company, any Significant Subsidiary (as defined in the Indenture) or group of Restricted Subsidiaries (as defined in the Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Notes to become due and payable.

Cash flows provided by (used in):

Operating Activities. During the year ended December 31, 2017, net cash provided by operating activities was $65.3 million, a 79% decrease from net cash provided by operating activities of $311.1 million for the same period in 2016. The decrease in net cash provided by operating activities was largely attributable to the payment of post-petition interest claims during the year ended December 31, 2017 as compared to the same period in 2016 and changes in working capital.

Investing Activities. During the year ended December 31, 2017, net cash used in investing activities was $435.3 million as compared to $278.9 million for the same period in 2016. The increase in net cash used in investing activities is largely related to increased capital investments associated with the Company's drilling activities, partially offset by the proceeds from the Pennsylvania Asset Sale.

Financing Activities. During the year ended December 31, 2017, net cash used in financing activities was $16.7 million as compared to net cash provided by financing activities of $368.6 million for the same period in 2016. The change in net cash used in financing activities is primarily due to the restructuring of debt and equity as a result of emergence from chapter 11 proceedings, the outflow of deferred financing costs and debt extinguishment costs associated with the restructuring of debt and equity.

Outlook

We believe we are well positioned for the current economic environment because of our status as a low-cost operator in the industry combined with our financial flexibility.

While our net cash provided by operating activities will continue to be impacted by changing commodity prices, we believe that we will generate positive cash flow from operations, which, along with our available cash and available borrowing capacity, will provide sufficient liquidity to fund our capital investments and operations over the next twelve months. We will continue to monitor and evaluate the impact of commodity prices in order to determine the appropriate size and nature of our capital investment program.

We have identified significant opportunities for production growth through our horizontal drilling program and will incorporate developing those opportunities as part of our future capital investment program.

We expect to rely on our available cash, existing credit facility, and the cash generated from operations to meet our obligations. While we continue to monitor the overall health of the credit markets, a renewed, long-term disruption in the credit markets could make financing more expensive or unavailable, which could have a material adverse effect on our operations.

Off-Balance Sheet Arrangements

The Company did not have any off-balance sheet arrangements as of December 31, 2017.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2017:

	Payments Due by period:				
	Total	Less than 1 year	1 to 3 years	3 to 5 years	More than 5 years
	(Amounts in thousands of U.S. dollars)				
Long-term debt	$ 2,175,000	$ —	$ 17,063	$ 719,500	$ 1,438,437
Interest payments (1)	754,474	127,373	254,172	228,392	144,537
Transportation contract (REX)	189,968	—	29,090	53,626	107,252
Operating lease — Liquids Gathering System	213,213	21,321	42,643	42,643	106,606
Office space lease	5,690	1,347	2,612	1,731	—
Total contractual obligations	$ 3,338,345	$ 150,041	$ 345,580	$ 1,045,892	$ 1,796,832

(1) Interest payments include projected interest payments based on the variable interest rates which were calculated assuming a 3-month London interbank offered rate plus 300 basis points as of December 31, 2017.

Outstanding debt and interest payments: On the Effective Date, the Company entered into new debt financing agreements consisting of the Term Loan Facility, the Notes, and the Revolving Credit Facility, see Note 1 for additional details. The Company included the principal and interest obligations above based on the respective agreements. See Note 5 for additional details.

Transportation contract. During our chapter 11 proceedings, Rockies Express Pipeline LLC ("REX") filed a claim against us for $303.3 million for breach of contract. As previously disclosed, on January 12, 2017, we agreed to settle their claim and paid the settlement amounts of $150.0 million during the year ended December 31, 2017. In connection with the settlement of REX's proof of claim, the Company agreed to enter into a new transportation agreement pursuant to which the Company will have firm transportation capacity of 200,000 Dekatherms per day at a rate of approximately $0.37 per dekatherm on the Rockies Express Pipeline, commencing on December 1, 2019 and extending for a term expiring December 31, 2026. This new agreement will provide the Company with the opportunity to transport a portion of its natural gas production away from its properties in Wyoming to capture improved basis differentials available at sales points along the Rockies Express Pipeline, if any.

Operating lease. During December 2012, the Company sold the Pinedale LGS and certain associated real property rights in the Pinedale Anticline in Wyoming and entered into a long-term, triple net lease agreement (the "Pinedale Operating Lease Agreement") relating to the use of the Pinedale LGS. The Pinedale Operating Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the Pinedale LGS at the sole discretion of the Company. Annual rent for the initial term under the Pinedale Operating Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index, which is 2.0% at January 1, 2018) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Office space lease. The Company maintains office space in Colorado, Texas, Wyoming and Utah with total remaining commitments for office leases of $5.7 million at December 31, 2017.

Item 7A.*Quantitative and Qualitative Disclosures About Market Risk*

Objectives and Strategy: The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program. These types of instruments may include fixed price swaps, costless collars, or basis differential swaps. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. While mitigating the effects of fluctuating commodity prices, these derivative contracts may limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecasted production volumes without Board approval.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the balance sheet and the associated unrealized gains and losses are recorded as current expense or income in the income statement. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the cash flow statement.

Commodity Derivative Contracts: At December 31, 2017, the Company had the following open commodity derivative contracts to manage commodity price risk. For the fixed price swaps, the Company receives the fixed price for the contract and pays the variable price to the counterparty. For the collars, the Company pays the counterparty if the market price is above the ceiling price and the counterparty pays the Company if the market price is below the floor price on a notional quantity. The reference prices of these commodity derivative contracts are typically referenced to index prices as published by independent third parties.

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Average Price/MMBTU	Fair Value - December 31, 2017
Natural Gas					Asset (Liability)
Fixed price swaps					
	NYMEX-Henry Hub	April-Oct 2018	380,000	$ 2.97	$ 15,419

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Floor Price ($/MMBTU)	Ceiling Price ($/MMBTU)	Fair Value - December 31, 2017
Collars						
	NYMEX-Henry Hub	Jan-Mar 2018	40,000	$ 3.23	$ 3.54	$ 1,446

Subsequent to December 31, 2017 and through February 15, 2018, the Company has entered into the following open commodity derivative contracts to manage commodity price risk.

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Average Price/MMBTU
Natural Gas				
Fixed price swaps				
	NYMEX-Henry Hub	April-Oct 2018	390,000	$ 2.79
	NYMEX-Henry Hub	Nov-Dec 2018	400,000	$ 2.88
	NYMEX-Henry Hub	Jan-Mar 2019	200,000	$ 2.91

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Average Differential/MMBTU
Natural Gas				
Basis Swap Contracts(1)	NW Rockies Basis Swap	Mar-Dec 2018	30,000	$ (0.58)
	NW Rockies Basis Swap	April-Oct 2018	140,000	$ (0.62)

Type	Commodity Reference Price	Remaining Contract Period	Volume/ Bbls/day	Average Price/Bbls
Crude Oil				
Fixed price swaps				
	NYMEX-WTI	Feb-Dec 2018	2,000	$ 62.17
	NYMEX-WTI	Mar-Dec 2018	2,000	$ 57.43

(1) Represents swap contracts that fix the basis differentials for gas sold at or near Opal, Wyoming and the value of natural gas established on the last trading day of the month by the NYMEX for natural gas swaps for the respective period.

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015:

Commodity Derivatives (000's):	For the Year Ended December 31, 2017	2016	2015
Realized gain on commodity derivatives-natural gas (1)	$ 11,446	$ —	$ 146,801
Unrealized gain (loss) on commodity derivatives (1)	16,966	—	(104,190)
Total gain on commodity derivatives	$ 28,412	$ —	$ 42,611

(1) Included in gain (loss) on commodity derivatives in the Consolidated Statements of Operations.

Item 8. ***Financial Statements and Supplementary Data.***

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for the preparation and integrity of all information contained in this Annual Report. The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America. The financial statements include amounts that are management's best estimates and judgments.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation under the framework in Internal Control — Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of our internal control over financial reporting has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Report of Independent Registered Public Accounting Firm

The Shareholders and Board of Directors of Ultra Petroleum Corp. and subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ultra Petroleum Corp. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, 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 at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 28, 2018 expressed an unqualified opinion thereon. –

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2006.

Houston, Texas

February 28, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Ultra Petroleum Corp. and subsidiaries

Opinion on Internal Control over Financial Reporting

We have audited Ultra Petroleum Corp. and subsidiaries' internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Ultra Petroleum Corp. and subsidiaries ("the Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and our report dated February 28, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

/s/ Ernst & Young LLP

Houston, Texas

February 28, 2018

Table of Contents

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2017	2016	2015
	(Amounts in thousands of U.S. dollars, except per share data)		
Revenues:			
Natural gas sales	$ 748,682	$ 609,756	$ 696,730
Oil sales	133,368	111,335	142,381
Other revenues	9,823	—	—
Total operating revenues	891,873	721,091	839,111
Expenses:			
Lease operating expenses	92,326	89,134	106,906
Facility lease expense	21,749	20,686	20,647
Production taxes	91,067	69,737	72,774
Gathering fees	86,953	86,809	87,904
Transportation charges	—	20,049	83,803
Depletion, depreciation and amortization	161,945	125,121	401,200
Ceiling test and other impairments	—	—	3,144,899
General and administrative	39,548	9,179	7,387
Total operating expenses	493,588	420,715	3,925,520
Operating income (loss)	398,285	300,376	(3,086,409)
Other (expense) income, net:			
Interest expense (excludes contractual interest expense of $141.5 million for the year ended December 31, 2016)	(361,367)	(66,565)	(171,918)
Gain on commodity derivatives	28,412	—	42,611
Deferred gain on sale of liquids gathering system	10,553	10,553	10,553
Litigation expense	—	—	(4,401)
Restructuring expenses	—	(7,176)	—
Contract settlement	(52,707)	(131,106)	—
Other (expense) income, net	(237)	(3,082)	(2,060)
Total other (expense) income, net	(375,346)	(197,376)	(125,215)
Reorganization items, net	140,907	(47,503)	—
Income (loss) before income tax benefit	163,846	55,497	(3,211,624)
Income tax benefit	(13,294)	(654)	(4,404)
Net income (loss)	$ 177,140	$ 56,151	$ (3,207,220)
Basic Earnings (Loss) per Share:			
Net income (loss) per common share — basic	$ 1.08	$ 0.70	$ (40.14)
Fully Diluted Earnings (Loss) per Share:			
Net income (loss) per common share — fully diluted	$ 1.08	$ 0.70	$ (40.14)
Weighted average common shares outstanding — basic	163,824	79,996	79,899
Weighted average common shares outstanding — fully diluted	163,976	80,363	79,899

Approved on behalf of the Board:

/s/ Michael D. Watford	/s/ Michael J. Keeffe
Chairman of the Board, Chief Executive Officer and President	Director

See accompanying notes to consolidated financial statements.

ULTRA PETROLEUM CORP. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(Amounts in thousands of U. S. dollars, except share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 16,631	$ 401,478
Restricted cash	1,638	3,571
Oil and gas revenue receivable	86,487	79,179
Joint interest billing and other receivables	16,616	10,781
Derivative asset	16,865	—
Income tax receivable	10,091	2,099
Inventory	13,450	4,906
Deposits and retainers	—	13,359
Other current assets	5,647	6,020
Total current assets	167,425	521,393
Oil and gas properties, net, using the full cost method of accounting:		
Proven	1,325,068	1,010,466
Property, plant and equipment	9,569	7,695
Other	10,920	1,374
Total assets	$ 1,512,982	$ 1,540,928
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 59,951	$ 28,171
Accrued liabilities	80,268	53,348
Production taxes payable	51,352	44,329
Interest payable	24,406	—
Capital cost accrual	32,513	12,360
Total current liabilities	248,490	138,208
Long-term debt	2,116,211	—
Deferred gain on sale of liquids gathering system	105,189	115,742
Other long-term obligations	197,728	177,088
Total liabilities not subject to compromise	2,667,618	431,038
Liabilities subject to compromise	—	4,038,041
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Common stock — no par value; authorized — unlimited; issued and outstanding shares — 196,346,736 and 80,017,020, at December 31, 2017 and 2016, respectively	2,116,018	510,063
Treasury stock	(49)	(49)
Retained loss	(3,270,605)	(3,438,165)
Total shareholders' deficit	(1,154,636)	(2,928,151)
Total liabilities and shareholders' equity	$ 1,512,982	$ 1,540,928

See accompanying notes to consolidated financial statements.

Table of Contents

ULTRA PETROLEUM CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Amounts in thousands of U.S. dollars, except share data)

	Shares Issued and Outstanding	Common Stock	Retained Loss	Treasury Stock	Total Shareholders' (Deficit) Equity
Balances at December 31, 2014	79,745	$ 495,913	$ (278,040)	$ (6,213)	$ 211,660
Employee stock plan grants	274	700	—	—	700
Shares re-issued from treasury	—	—	(6,037)	6,037	—
Net share settlements	(86)	—	(2,514)	—	(2,514)
Fair value of employee stock plan grants	—	5,437	—	—	5,437
Net (loss)	—	—	(3,207,220)	—	(3,207,220)
Balances at December 31, 2015	79,933	$ 502,050	$ (3,493,811)	$ (176)	$ (2,991,937)
Employee stock plan grants	145	—	—	—	—
Shares re-issued from treasury	—	—	(127)	127	—
Net share settlements	(61)	—	(378)	—	(378)
Fair value of employee stock plan grants	—	8,013	—	—	8,013
Net income	—	—	56,151	—	56,151
Balances at December 31, 2016	80,017	$ 510,063	$ (3,438,165)	$ (49)	$ (2,928,151)
Equitization of Holdco Notes	70,579	978,230	—	—	978,230
Rights Offering, including Backstop	44,390	573,774	—	—	573,774
Employee stock plan grants	10	—	—	—	—
Stock plan grants	2,191	26,673	—	—	26,673
Net share settlements	(841)	—	(9,580)	—	(9,580)
Fair value of employee stock plan grants	—	27,278	—	—	27,278
Net income	—	—	177,140	—	177,140
Balances at December 31, 2017	196,346	$ 2,116,018	$ (3,270,605)	$ (49)	$ (1,154,636)

See accompanying notes to consolidated financial statements.

Shareholders' Equity Explanatory Note:

In conjunction with emergence from chapter 11 proceedings, the Company issued new Common Shares to holders of existing pre-petition Common Shares (the "Existing Common Shares") at a conversion ratio of 0.521562 (the "New Equity"). As a result, the share counts have been adjusted to reflect this conversion as if it had occurred as of January 1, 2014.

Consistent with the Plan, 194,991,656 shares of New Equity were issued as follows:

- 70,579,367 shares of New Equity were issued pro rata to holders of the HoldCo Notes with claims allowed under the *Debtors' Second Amended Joint Chapter 11 Plan of Reorganization*;
- 80,022,410 shares of New Equity were issued pro rata to holders of Existing Common Shares;
- 2,512,623 shares of New Equity were issued to commitment parties under the Backstop Commitment Agreement in respect of the commitment premium due thereunder;
- 18,844,363 shares of New Equity were issued to commitment parties under the Backstop Commitment Agreement in connection with their backstop obligation thereunder; and
- 23,032,893 shares of New Equity were issued to participants in the Rights Offering.

Table of Contents

ULTRA PETROLEUM CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2017	2016	2015
	(Amounts in thousands of U.S. dollars)		
Cash provided by (used in):			
Operating activities:			
Net income (loss) for the period	$ 177,140	$ 56,151	$ (3,207,220)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depletion, depreciation and amortization	161,945	125,121	401,200
Ceiling test and other impairments	—	—	3,144,899
Deferred and current non-cash income taxes	—	1	(990)
Unrealized (gain) loss on commodity derivatives	(16,966)	—	104,190
Deferred gain on sale of liquids gathering system	(10,553)	(10,553)	(10,553)
Stock compensation	39,977	5,562	4,128
Non-cash reorganization items, net	(453,909)	42,523	—
Amortization of deferred financing costs	7,483	4,194	5,190
Other	(1,047)	2,676	4,027
Net changes in operating assets and liabilities:			
Accounts receivable	(14,483)	(19,635)	65,132
Other current assets	14,136	(15,647)	(20,106)
Other non-current assets	479	(539)	21,112
Accounts payable	34,349	(63,924)	13,815
Accrued liabilities	89,935	133,144	1,655
Production taxes payable	7,023	(7,944)	(3,312)
Interest payable	36,220	57,117	(3,441)
Other long-term obligations	4,737	276	(5,770)
Current taxes payable/receivable	(11,198)	2,547	1,580
Net cash provided by operating activities	65,268	311,070	515,536
Investing Activities:			
Oil and gas property expenditures	(557,029)	(269,314)	(494,025)
Acquisition of oil and gas properties	—	—	3,964
Sale of oil and gas properties	114,263	—	—
Change in capital cost accrual	20,076	(8,134)	(25,380)
Inventory	(8,916)	(1,123)	3,235
Purchase of property, plant and equipment	(3,705)	(329)	(551)
Net cash used in investing activities	(435,311)	(278,900)	(512,757)
Financing activities:			
Borrowings under Credit Agreement	773,000	369,000	1,165,000
Borrowings under Term Loan	975,000	—	—
Extinguishment of long-term debt (chapter 11)	(2,459,000)	—	—
Payments under Credit Agreement	(773,000)	—	(1,153,000)
Proceeds from issuance of Senior Notes	1,200,000	—	—
Deferred financing costs	(73,092)	—	6
Shares issued, net of transaction costs	573,774	—	—
Repurchased shares/net share settlements	(9,581)	(379)	(2,514)
Payment of contingent consideration	—	—	(17,049)
Debt extinguishment costs	(223,838)	—	—
Net cash (used in) provided by financing activities	(16,737)	368,621	(7,557)
(Decrease)/Increase in cash during the period	(386,780)	400,791	(4,778)
Cash, cash equivalents, and restricted cash at beginning of period	405,049	4,258	9,036
Cash, cash equivalents, and restricted cash end of period	$ 18,269	$ 405,049	$ 4,258
SUPPLEMENTAL INFORMATION:			
Cash paid for:			
Interest	$ 317,120	$ 4,793	$ 169,867
Income taxes	$ —	$ 94	$ —

See accompanying notes to consolidated financial statements.

(All amounts in this Report on Form 10-K are expressed in thousands of U.S. dollars (except per share data), unless otherwise noted).

DESCRIPTION OF THE BUSINESS:

Ultra Petroleum Corp. (the "Company") is an independent oil and gas company engaged in the development, production, operation, exploration and acquisition of oil and natural gas properties. The Company is incorporated under the laws of Yukon, Canada. The Company's principal business activities are developing its long-life natural gas reserves in the Green River Basin of Wyoming – the Pinedale and Jonah fields and its oil reserves in the Uinta Basin in Utah.

Chapter 11 Proceedings

Voluntary Reorganization Under Chapter 11and Ability to Continue as a Going Concern

On April 29, 2016 (the "Petition Date"), the Company and its subsidiaries (collectively, "the Debtors") filed voluntary petitions under chapter 11 of title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). Our chapter 11 cases were jointly administered under the caption *In re Ultra Petroleum Corp.,* et al, (Case No. 16-32202 (MI). On March 14, 2017, the Bankruptcy Court confirmed our *Debtors' Second Amended Joint Chapter 11 Plan of Reorganization* (the "Plan"), and on April 12, 2017 (the "Effective Date"), we emerged from bankruptcy.

As a result of its improved financial condition and successful emergence from chapter 11, the Company believes it has sufficient liquidity along with funds generated from ongoing operations, to fund anticipated cash requirements for operations, capital expenditures and working capital purposes. As a result, substantial doubt no longer exists regarding the Company's ability to meet its obligations as they become due within one year after the date that the financial statements are issued.

Plan Support Agreement, Rights Offering, Backstop Commitment Agreement and Exit Financing

On November 21, 2016, each of the Ultra Entities entered into a Plan Support Agreement ("PSA") with (i) holders of at least 66.67% of the principal amount of the Company's outstanding 5.750% Senior Notes due 2018 and 6.125% Senior Notes due 2024 and (ii) shareholders who own at least a majority of the Company's outstanding common stock or the economic interests therein (collectively, the "Plan Support Parties") and a Backstop Commitment Agreement ("BCA") with a subset thereof (collectively, the "Commitment Parties").

Plan Support Agreement: The PSA enumerated the terms and conditions pursuant to which the Ultra Entities and the Commitment Parties agreed to seek and support a joint plan of reorganization. The Plan consummated on the Effective Date was the joint plan of reorganization contemplated in the PSA.

Rights Offering: In accordance with the Plan, the BCA and the Rights Offering procedures submitted by the Company in connection with the Plan, the Company offered eligible debt and equity holders, including the Commitment Parties, the right to purchase shares of new common stock in the Company upon effectiveness of the Plan for an aggregate purchase price of $580.0 million. The Rights Offering was consummated upon the Company's emergence from bankruptcy on the Effective Date. Pursuant to the Rights Offering:

- HoldCo Noteholders were granted rights (the "HoldCo Noteholder Rights Offering") entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the "HoldCo Noteholder Rights Offering Shares"), which HoldCo Noteholder Rights Offering Shares, collectively, reflected an aggregate purchase price of $435.0 million.
- HoldCo Equityholders were granted rights (the "HoldCo Equityholder Rights Offering") entitling each such holder to subscribe for the Rights Offering in an amount up to its pro rata share of new common stock (the "HoldCo Equityholder Rights Offering Shares" and, together with the HoldCo Noteholder Rights Offering Shares, the "Rights Offering Shares"), which HoldCo Equityholder Rights Offering Shares, collectively, reflected an aggregate purchase price of $145.0 million.

Backstop Commitment Agreement: Under the BCA, the Commitment Parties agreed to purchase the HoldCo Noteholder Rights Offering Shares and the HoldCo Equityholder Rights Offering Shares, as applicable, that were not duly subscribed for pursuant to the HoldCo Noteholder Rights Offering or the HoldCo Equityholder Rights Offering, as applicable, by parties other than Commitment Parties (the "Backstop Commitment") at an implied 20% discount to the Plan Value, which is the price for the rights offering set forth in the PSA (the "Rights Offering Price"). In connection with our emergence from bankruptcy on the Effective Date, the Commitment Parties performed the Backstop Commitment as and to the extent provided for in the BCA. In addition, on the Effective Date, the Company paid the Commitment Parties a Commitment Premium equal to 6.0% of the $580.0 million committed amount. The commitment premium was paid in the form of new common stock at the Rights Offering Price.

Exit Financing: On February 8, 2017, the Debtors obtained a commitment letter (as amended, the "Commitment Letter") from Barclays Bank PLC (including any affiliates that may perform its responsibilities thereunder, "Barclays"), pursuant to which, in connection with the consummation of the Plan, Barclays agreed to provide us with secured and unsecured financing in an aggregate amount of up to $2.4 billion.

On the Effective Date, in connection with the consummation of our Plan:

- Ultra Resources entered into a Credit Agreement dated April 12, 2017 with Bank of Montreal, as administrative agent, and with the other lenders party thereto (the "RBL Credit Agreement"), providing for a revolving credit facility (the "Revolving Credit Facility") for an aggregate amount of $400.0 million;
- Ultra Resources entered into a Senior Secured Term Loan Agreement dated April 12, 2017 with Barclays Bank PLC, as administrative agent, and with the other lenders party thereto (the "Term Loan Agreement"), providing for senior secured first lien term loans for an aggregate amount of $800.0 million;
- Ultra Resources entered into an Indenture dated April 12, 2017 with Wilmington Trust, as trustee (the "Indenture"), and also issued the $700.0 million of its 6.875% unsecured senior notes due 2022 (the "2022 Notes") and $500.0 million of its 7.125% unsecured senior notes due 2025 (the "2025 Notes" and, collectively with the 2022 Notes, the "Notes"), as contemplated in the Purchase Agreement. The 2022 Notes were sold at an issue price of 100% and the 2025 Notes were sold at an issue price of 98.507%, and the issuance of the 2022 Notes and the 2025 Notes resulted in net proceeds (after deducting purchasers' discounts and commissions) to Ultra Resources of $1.185 billion.
- The principal obligations outstanding of $999.0 million under the Prepetition Credit Agreement and $1.46 billion under the Prepetition Senior Notes, as well as prepetition interest and other undisputed amounts, were paid in full. The Company's obligations under the Prepetition Credit Agreement and Prepetition Senior Notes were cancelled and extinguished as provided in the Plan.
- The claims of $450.0 million related to the unsecured 2018 Notes and $850.0 million related to the unsecured 2024 Notes were allowed in full, each holder of a claim related to the 2018 and 2024 Notes received a distribution of common stock in the amount of the holders' applicable claim and the Company's obligations under the 2018 Notes and 2024 Notes were cancelled and extinguished as provided in the Plan.

Ultra Resources' obligations under the RBL Credit Agreement, the Term Loan Agreement, the Indenture, and the Notes are guaranteed by the Company and each of its subsidiaries (other than Ultra Resources). In addition, on the Effective Date, the Company and each of its subsidiaries (other than Ultra Resources) entered into a Guaranty and Collateral Agreement in favor of Bank of Montreal, as administrative agent, for the benefit of the secured parties under the RBL Credit Agreement and the Term Loan Agreement.

The Company's obligations under the Revolving Credit Facility and the Term Loan Agreement are secured by first priority, perfected liens and security interests on 85% of the total value of proved oil and gas properties evaluated in reserve reports delivered to the lenders under the Revolving Credit Facility, as well as a negative pledge on substantially all non-mortgaged assets of the Company and other guarantors under the Revolving Credit Facility

For further description of the emergence financing and for other information and changes to the Company's debt financing subsequent to the Effective Date, see Note 5.

Fresh Start Accounting

As previously disclosed, we are not required to apply fresh start accounting to our financial statements in connection with our emergence from bankruptcy because the reorganization value of our assets immediately prior to confirmation of the Plan exceeded our aggregate postpetition liabilities and allowed claims.

Liabilities Subject to Compromise

The following table reconciles the settlement of liabilities subject to compromise included in our Consolidated Balance Sheets from December 31, 2016 through December 31, 2017:

	December 31, 2017
Liabilities subject to compromise at December 31, 2016	4,038,041
Debt extinguishment-cash	(2,521,493)
Debt extinguishment-non-cash	(1,339,740)
Contract settlement	(169,600)
Reclassified to accrued liabilities	(7,208)
Liabilities subject to compromise at December 31, 2017	$ —

Bankruptcy Claims Resolution Process

The claims filed against us during our chapter 11 proceedings were voluminous. In addition, claimants may file amended or modified claims in the future, which modifications or amendments may be material. The claims resolution process is on-going, and the ultimate number and amount of prepetition claims is not presently known, nor can the ultimate recovery with respect to allowed claims be presently ascertained.

As a part of the claims resolution process, we are working to resolve differences between amounts we listed in information filed during our bankruptcy proceedings and the amounts of claims filed by our creditors. We have filed, and we will continue to file, objections with the Bankruptcy Court as necessary with respect to claims we believe should be disallowed.

Costs of Reorganization

We have incurred significant costs associated with our reorganization and the chapter 11 proceedings. We expect these costs, which are being expensed as incurred, will significantly affect our results of operations. For additional information about the costs of our reorganization and chapter 11 proceedings, see "Reorganization items, net" below.

The following table summarizes the components included in Reorganization items, net in our Consolidated Statements of Operations for the years ended December 31, 2017, 2016, and 2015:

	For the Twelve Months Ended December 31,		
	2017	2016	2015
Professional fees (1)	$ (66,529)	$ (11,781)	$ —
Gains (losses) (2)	431,107	—	—
Deferred financing costs	—	(18,742)	—
Contract settlements	—	(17,350)	—
Make-whole fees (3)	(223,838)	—	—
Other (4)	167	370	—
Total Reorganization items, net	$ 140,907	$ (47,503)	$ —

(1) The year ended December 31, 2017 includes $1.1 million directly related to accrued, unpaid professional fees associated with the chapter 11 filings.

(2) Gains (losses) represent the net gain on the debt to equity exchange related to the 2018 and 2024 Notes.

(3) Make-whole fees represent the Bankruptcy Court order denying our objection to the make-whole claims, as further described in Note 11.

(4) Cash interest income earned for the period after the Petition Date on excess cash over normal invested capital.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) *Basis of presentation and principles of consolidation*: The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company presents its financial statements in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). All inter-company transactions and balances have been eliminated upon consolidation.

(b) *Cash and Cash Equivalents:* The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(c) *Restricted Cash:* Restricted cash represents and cash received by the Company from production sold where the final division of ownership of the production is unknown or in dispute.

(d) *Accounts Receivable:* Accounts receivable are stated at the historical carrying amount net of write-offs and an allowance for uncollectible accounts. The carrying amount of the Company's accounts receivable approximates fair value because of the short-term nature of the instruments. The Company routinely assesses the collectability of all material trade and other receivables.

(e) *Property, Plant and Equipment:* Capital assets are recorded at cost and depreciated using the declining-balance method based on their respective useful life.

(f) *Oil and Natural Gas Properties:* The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission ("SEC") Release No. 33-8995, Modernization of Oil and Gas Reporting Requirements ("SEC Release No. 33-8995") and Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 932, Extractive Activities – Oil and Gas ("FASB ASC 932"). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the Company's proved reserves. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement costs are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. The Company reviews its unproved leasehold costs quarterly or when management determines that events or circumstances indicate that the recorded carrying value of the unevaluated properties may not be recoverable. The fair values of unproved properties are evaluated utilizing a discounted net cash flows model based on management's assumptions of future oil and gas production, commodity prices, operating and development costs; as well as appropriate discount rates. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors. The amount of any impairment is transferred to the capitalized costs being amortized.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing the average of prices in effect on the first day of the month for the preceding twelve-month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company did not have any write-downs related to the full cost ceiling limitation in 2017 or 2016. During 2015, the Company recorded a $3.1 billion non-cash write-down of the carrying value of the Company's proved oil and gas properties as a result of ceiling test limitations, which is reflected within ceiling test and other impairments in the accompanying Consolidated Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve-month period at December 31, 2015 for Henry Hub natural gas and West Texas Intermediate oil, adjusted for market differentials.

(g) *Inventories:* Inventory primarily includes $12.3 million in pipe and production equipment that will be utilized during the 2018 drilling program and $1.1 million in crude oil inventory. Materials and supplies inventories are carried at lower of cost or market and include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. The Company uses the weighted average method of recording its materials and supplies inventory. Crude oil inventory is valued at lower of cost or market.

(h) *Derivative Instruments and Hedging Activities:* The Company follows FASB ASC Topic 815, Derivatives and Hedging ("FASB ASC 815"). The Company records the fair value of its commodity derivatives as an asset or liability in the Consolidated Balance Sheets, and records the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations. The Company does not offset the value of its derivative arrangements with the same counterparty. (See Note 7).

(i) *Deferred Financing Costs:* At December 31, 2017, the Company follows ASU No. 2015-13, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* and includes the costs for issuing debt including issuance discounts, except those related to the revolving credit facility, as a direct deduction from the carrying amount of the related debt liability. Costs related to the issuance of the revolving credit facility are recorded as an asset in the Consolidated Balance Sheets.

(j) *Income Taxes:* Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are recorded related to deferred tax assets based on the "more likely than not" criteria described in FASB ASC Topic 740, Income Taxes . In addition, the Company recognizes the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit.

(k) *Equity Interests:* In accordance with the Plan, the Company's equity interests outstanding prior to the Effective Date were cancelled and each such equity interest has no further force or effect after the Effective Date. Pursuant to the Plan, the holders of the Company's common shares outstanding prior to the Effective Date (the "Existing Common Shares") received (i) their proportionate distribution of New Equity and (ii) the right to participate in the Rights Offering. The holders of all other equity interest in the company received no distribution under the Plan in respect thereof.

(l) *Earnings (Loss) Per Share:* Basic earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted earnings (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect.

In conjunction with our emergence from chapter 11 proceedings, on the Effective Date, the Company issued shares of New Equity to holders of Existing Common Shares at a conversion ratio of 0.521562. As a result, the basic and fully diluted share counts have been presented to reflect this conversion as if it had occurred on January 1, 2015.

Share based payments subject to performance or market conditions are considered contingently issuable shares for purposes of calculating diluted earnings per share. Thus, they are not included in the diluted earnings per share denominator until the performance or market criteria are met. For the year ended December 31, 2017, the Company had 3.9 million contingently issuable shares that are not included in the diluted earnings per share denominator as the performance or market criteria have not been met (See Note 6). There were no contingently issuable shares outstanding for the years ended December 31, 2016 and 2015. The following table provides a reconciliation of components of basic and diluted net income (loss) per common share:

	December 31, 2017	2016	2015
Net income (loss)	$ 177,140	$ 56,151	$ (3,207,220)
Weighted average common shares outstanding during the period	163,824	79,996	79,899
Effect of dilutive instruments	152	367	—
Weighted average common shares outstanding during the period including the effects of dilutive instruments	163,976	80,363	79,899
Net income (loss) per common share — basic	$ 1.08	$ 0.70	$ (40.14)
Net income (loss) per common share — fully diluted	$ 1.08	$ 0.70	$ (40.14)
Number of shares not included in dilutive earnings per share that would have been anti-dilutive because the exercise price was greater than the average market price of the common shares (1)	—	749	—

(1) Due to the net loss for the year ended December 31, 2015, 1.7 million shares for options and restricted stock units were anti-dilutive and excluded from the computation of net loss per share.

(m) *Use of Estimates:* Preparation of consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(n) *Accounting for Share-Based Compensation:* The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values in accordance with FASB ASC Topic 718, Compensation – Stock Compensation.

(o) *Fair Value Accounting:* The Company follows FASB ASC Topic 8 20, Fair Value Measurements and Disclosures ("FASB ASC 820"), which defines fair value, establishes a framework for measuring fair value under GAAP, and expands disclosures about fair value measurements. This statement applies under other accounting topics that require or permit fair value measurements. See Note 8 for additional information.

(p) *Asset Retirement Obligation:* The initial estimated retirement obligation of properties is recognized as a liability with an associated increase in oil and gas properties for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations. As a full cost company, settlements for asset retirement obligations for abandonment are adjusted to the full cost pool. The asset retirement obligation is included within other long-term obligations in the accompanying Consolidated Balance Sheets.

(q) *Revenue Recognition:* The Company generally sells oil and natural gas under both long-term and short-term agreements at prevailing market prices. The Company recognizes revenues when the oil and natural gas is delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company accounts for oil and natural gas sales using the "entitlements method." Under the entitlements method, revenue is recorded based upon the Company's ownership share of volumes sold, regardless of whether it has taken its ownership share of such volumes. Any amount received in excess of the Company's share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable.

Make-up provisions and ultimate settlements of volume imbalances are generally governed by agreements between the Company and its partners with respect to specific properties or, in the absence of such agreements, through negotiation. The value of volumes over- or under-produced can change based on changes in commodity prices. The Company prefers the entitlements method of accounting for oil and natural gas sales because it allows for recognition of revenue based on its actual share of jointly owned production, results in better matching of revenue with related operating expenses, and provides balance sheet recognition of the estimated value of product imbalances. The Company's imbalance obligations as of December 31, 2017 and December 31, 2016 were immaterial.

(r) *Other revenues:* Other revenues are comprised of fees paid to us by operators of the gas processing plants where our gas is processed in exchange for the liquids removed from our production.

(s) *Capitalized Interest:* Interest is capitalized on the cost of unevaluated gas and oil properties that are excluded from amortization and actively being evaluated, if any.

(t) *Capital Cost Accrual:* The Company accrues for exploration and development costs in the period incurred, while payment may occur in a subsequent period.

(u) *Reclassifications:* Certain amounts in the financial statements of prior periods have been reclassified to conform to the current period financial statement presentation.

(v) *Deposits and Retainers:* Deposits and retainers primarily consists of payments related to surety bonds.

(w) *Recent Accounting Pronouncements:*

Statement of Cash Flows: In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* ("ASU No. 2016-18"). The guidance requires that an explanation is included in the cash flow statement of the change in the total of (1) cash, (2) cash equivalents, and (3) restricted cash or restricted cash equivalents. The ASU also clarifies that transfers between cash, cash equivalents and restricted cash or restricted cash equivalents should not be reported as cash flow activities and requires the nature of the restrictions on cash, cash equivalents, and restricted cash or restricted cash equivalents to be disclosed. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. We early adopted ASU 2016-18 at December 31, 2017 and disclosure revisions have been made for the years presented on the Consolidated Statements of Cash Flows. All prior periods have been adjusted to conform, which resulted in a (decrease)/increase in cash flows from operating activities of approximately ($1.9) million, $3.5 million, and ($0.2) million for the years ended December 31, 2017, 2016, and 2015 respectively. See the following table for a reconciliation of cash, cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the same amounts shown in the Consolidated Statement of Cash Flows.

Current Presentation	**December 31, 2017**		**December 31, 2016**		**December 31, 2015**	
Cash and Cash Equivalents	$	16,631	$	401,478	$	4,143
Restricted Cash		1,638		3,571		115
Total cash, cash equivalents, and restricted cash	$	18,269	$	405,049	$	4,258

Statement of Cash Flows: In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)* ("ASU No. 2016-15"). ASU 2016-15 provides guidance on eight specific cash flow issues with the objective of reducing diversity in practice in regard to how cash receipts and cash payments are presented and classified in the statement of cash flows. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. We early adopted ASU 2016-15 at December 31, 2017. The guidance was applied retrospectively as required by the standard. For the year ended December 31, 2017, the material impact to the Consolidated Statement of Cash Flows was the reclassification of costs related to the extinguishment of long-term debt from cash flows provided by operating activities to cash flows used in financing activities totaling $223.8 million. There was no material impact to the Consolidated Statement of Cash Flows for the years ended December 31, 2016 and 2015.

Leases: In February 2016, the FASB issued ASU 2016-02, *Leases* ("ASU No. 2016-02"). The guidance requires that lessees will be required to recognize assets and liabilities on the balance sheet for the rights and obligations created by all leases with terms of more than 12 months. The ASU will also require disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. These disclosures include qualitative and quantitative information. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 with earlier application permitted. The Company is evaluating the impact of ASU No. 2016-02 on its financial position and results of operations.

Stock Compensation: In May 2017, the FASB issued ASU 2017-9, *Compensation-Stock Compensation (Topic 718)* ("ASU No. 2017-09")*,* which is intended to clarify and reduce diversity in practice and cost and complexity when applying the guidance in Topic 718, Compensation-Stock Compensation, to a change to the terms or conditions of a share-based payment award. For public companies, the standard will take effect for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017 with earlier application permitted. The Company does not expect the adoption of ASU No. 2017-08 to have a material impact on its consolidated financial statements.

Derivatives: In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815)* ("ASU No. 2017-12"), which makes significant changes to the current hedge accounting rules. The new guidance impacts the designation of hedging relationships; measurement of hedging relationships; presentation of the effects of hedging relationships; assessment of hedge effectiveness; and disclosures. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. The Company does not expect the adoption of ASU No. 2017-12 to have a material impact on its consolidated financial statements.

Revenues from Contracts with Customers: In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) and in 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), and ASU 2016-10, Revenues from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, which supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition. The new standard requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services.

We have evaluated the provisions of ASU 2014-09 and assessed the impact it may have on our financial position and results of operations. As part of our assessment work, we have done the following:

- We have completed training of the new ASU's revenue recognition model, dedicated resources to its implementation, and initiated contract review and documentation; including analyzing the standard's impact on our contract portfolio, comparing historical accounting policies and practices to the requirements of the new standard, and identifying differences from applying the requirements of the new standards to our contracts.
- We have evaluated each revenue stream, including sales of oil, natural gas, and other revenues, noting no significant changes to revenue recognition under the new standard except as noted below.
- We had previously elected to utilize the entitlements method, which will no longer be applicable under ASU 2014-09. We do not anticipate the change from the entitlements method to have a material impact on our financial statements.
- We evaluated our product sales contracts in order to determine if there were remaining performance obligations. We have determined that our product sales are primarily short-term in nature with contract periods of one year or less. We have evaluated product sales contracts with terms greater than one year and anticipate using the practical expedient in ASC 606-10-50-14(a) which will not require disclosure of the transaction price allocated to remaining performance obligations.
- We have evaluated our product sales contracts and do not anticipate them to give rise to contract assets or liabilities.
- We have evaluated the expanded disclosure requirements under the new standard and reviewed our processes, systems, and internal controls over financial reporting to ensure the appropriate information will be available for these disclosures. We do not anticipate any issues in providing the appropriate information to be available for the disclosures.

The Company is required to adopt the new standards in the first quarter of 2018 using one of two application methods: retrospectively to each prior reporting period presented (full retrospective method), or retrospectively with the cumulative effect of initially applying the guidance recognized at the date of initial application (the modified retrospective method). The Company will adopt the standard as of January 1, 2018 using the modified retrospective method. The Company is currently estimating the impact to beginning retained earnings to be immaterial to the overall consolidated financial statements based on implementation through the modified retrospective approach.

2. ASSET RETIREMENT OBLIGATIONS:

The Company is required to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The following table summarizes the activities for the Company's asset retirement obligations for the years ended:

	December 31, 2017	December 31, 2016
Asset retirement obligations at beginning of period	$ 157,173	$ 146,210
Accretion expense	11,689	10,252
Liabilities incurred	8,174	1,317
Liabilities divested (1)	(4,812)	—
Liabilities acquired	1,456	—
Liabilities settled	(598)	(170)
Revisions of estimated liabilities	18	(436)
Asset retirement obligations at end of period	173,100	157,173
Less: current asset retirement obligations	(263)	(239)
Long-term asset retirement obligations	$ 172,837	$ 156,934

(1) During the quarter ended December 31, 2017, the Company divested certain non-core properties in north-central Pennsylvania for net cash proceeds of approximately $115.0 million, subject to post-close adjustments.

3. OIL AND GAS PROPERTIES:

	December 31, 2017	December 31, 2016
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 11,215,563	$ 10,752,642
Less: Accumulated depletion, depreciation and amortization	(9,890,495)	(9,742,176)
	1,325,068	1,010,466

On a unit basis, DD&A was $0.59, $0.44 and $1.38 per Mcfe for the years ended December 31, 2017, 2016 and 2015, respectively.

4. PROPERTY, PLANT AND EQUIPMENT:

	December 31, 2017			December 31, 2016
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Computer equipment	3,018	(2,464)	554	603
Office equipment	309	(214)	95	138
Leasehold improvements	486	(366)	120	185
Land	4,637	—	4,637	4,637
Other	15,773	(11,610)	4,163	2,132
Property, plant and equipment, net	$ 24,223	$ (14,654)	$ 9,569	$ 7,695

5. DEBT AND OTHER LONG-TERM LIABILITIES:

	December 31, 2017	December 31, 2016
Total Debt:		
Term loan, secured, due 2024	$ 975,000	$ —
6.875% Senior, unsecured Notes due 2022	700,000	—
7.125% Senior, unsecured Notes due 2025	500,000	—
6.125% Senior Notes due 2024	—	850,000
5.75% Senior Notes due 2018	—	450,000
Senior Notes issued by Ultra Resources, Inc.	—	1,460,000
Credit Agreement	—	999,000
Total long-term debt	2,175,000	3,759,000
Less: Deferred financing costs	(58,789)	—
Less: Liabilities subject to compromise (1) (See Note 1)	—	(3,759,000)
Total long-term debt not subject to compromise	$ 2,116,211	$ —
Other long-term obligations:		
Other long-term obligations	$ 197,728	$ 177,088

Aggregate maturities of debt at December 31, 2017:

2018	2019	2020	2021	2022	Beyond 5 years	Total
$ —	$ 7,313	$ 9,750	$ 9,750	$ 709,750	$ 1,438,437	$ 2,175,000

(1) All of our indebtedness that was outstanding as of December 31, 2016 was classified as liabilities subject to compromise in the Consolidated Balance Sheets. See below for information about the indebtedness we incurred in connection with, and that is now outstanding following our emergence from bankruptcy.

On the Effective Date, all principal, prepetition interest and other undisputed amounts were paid in full for the amounts owed under the Prepetition Credit Agreement and the Prepetition Senior Notes shown in the table above and the Company's obligations under the Prepetition Credit Agreement and Prepetition Senior Notes were cancelled and extinguished. The claims related to the 2018 and 2024 Notes, shown in the table above were allowed in full, each claim holder received a distribution of our comment stock in the amount of the applicable claim, and the Company's obligations under the 2018 and 2024 Notes were cancelled and extinguished.

Ultra Resources, Inc.

Credit Agreement. On April 12, 2017, Ultra Resources, Inc. ("Ultra Resources"), as the borrower, entered into a Credit Agreement with the Company and UP Energy Corporation, as parent guarantors, with Bank of Montreal, as administrative agent, and with the other lenders party thereto from time to time (as amended, the "RBL Credit Agreement"), providing for a revolving credit facility (the "Revolving Credit Facility," for an aggregate amount of $400.0 million and an initial borrowing base of $1.2 billion (which limits the aggregate amount of first lien debt under the Revolving Credit Facility and the Term Loan Facility (defined below)). On September 19, 2017, the Bank of Montreal, as administrative agent, and the other lenders party thereto, approved an increase in the borrowing base under the RBL Credit Agreement from $1.2 billion to $1.4 billion as requested by the Company, which included an increase in the commitments under the RBL Credit Agreement to an aggregate amount of $425.0 million. At December 31, 2017, Ultra Resources did not have any outstanding borrowings under the RBL Credit Agreement, had total commitments under the RBL Credit Agreement of $425.0 million, and a borrowing base of $1.4 billion. There are no scheduled borrowing base redeterminations until April 1, 2018.

The Revolving Credit Facility has capacity for Ultra Resources to increase the commitments subject to certain conditions, and had $50.0 million of the commitments available for the issuance of letters of credit. During the quarter ended December 31, 2017, the Company utilized $34.5 million of the commitments available for the issuance of a letter of credit associated with the Pennsylvania Asset Sale. The Revolving Credit Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus an applicable margin that varies from 250 to 350 basis points or (b) the base rate plus an applicable margin that varies from 150 to 250 basis points. The interest rate remained the same for the Revolving Credit Facility subsequent to the approved commitments increase noted above. The Revolving Credit Facility loans mature on January 12, 2022.

The RBL Credit Agreement requires Ultra Resources to maintain (i) an interest coverage ratio of 2.50 to 1.00; (ii) a current ratio, including the unused portion of the Revolving Credit Facility of 1.00 to 1.00; (iii) a consolidated net leverage ratio of (A) 4.25 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2017 and (B) 4.00 to 1.00, as of the last day of any fiscal quarter thereafter; and (iv) after the Company has obtained investment grade rating an asset coverage ratio of 1.50 to 1.00. At December 31, 2017, Ultra Resources was in compliance with all of its debt covenants under the RBL Credit Agreement.

Ultra Resources is required to pay a commitment fee on the average daily unused portion of the Revolving Credit Facility, which varies based upon a borrowing base utilization grid. Ultra Resources is also required to pay customary letter of credit and fronting fees.

The RBL Credit Agreement also contains customary affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments, hedging requirements and other customary covenants.

The RBL Credit Agreement contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the RBL Credit Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the RBL Credit Agreement and any outstanding unfunded commitments may be terminated.

Term Loan. On April 12, 2017, Ultra Resources, as borrower, entered into a Senior Secured Term Loan Agreement with the Company and UP Energy Corporation, as parent guarantors, Barclays Bank PLC, as administrative agent, and the other lenders party thereto (the “Term Loan Agreement”), providing for senior secured first lien term loans for an aggregate amount of $800.0 million consisting of an initial term loan in the amount of $600.0 million and an incremental term loan in the amount of $200.0 million to be drawn immediately after the funding of the initial term loan. On September 29, 2017, the Company closed an incremental senior secured term loan offering of $175.0 million, increasing total borrowings under the Term Loan Agreement to $975.0 million (the “Term Loan Facility”). As part of the Term Loan agreement, Ultra Resources agreed to pay an original issue discount equal to one percent of the principal amount, which is included in deferred financing costs noted above. The Term Loan Agreement has capacity to increase the commitments subject to certain conditions. At December 31, 2017, Ultra Resources had $975.0 million in outstanding borrowings under the Term Loan Facility.

The Term Loan Facility bears interest either at a rate equal to (a) a customary London interbank offered rate plus 300 basis points or (b) the base rate plus 200 basis points. The Term Loan Facility amortizes in equal quarterly installments in aggregate annual amounts equal to 0.25% of the aggregate principal amount beginning on June 30, 2019. The Term Loan Facility matures seven years after the Effective Date.

The Term Loan Facility is subject to mandatory prepayments and customary reinvestment rights. The mandatory prepayments include, without limitation, a prepayment requirement with the total net proceeds from certain asset sales and net proceeds on insurance received on account of any loss of Ultra Resources’ property or assets, in each case subject to certain exceptions. In addition, subject to certain exceptions, there is a prepayment requirement if the asset coverage ratio is less than 2.0 to 1.0. To the extent any mandatory prepayments are required, prepayments are applied to prepay the Term Loan Facility.

The Term Loan Agreement also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), delivery of quarterly and annual financial statements and oil and gas engineering reports, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens, indebtedness, asset dispositions, fundamental changes, restricted payments and other customary covenants. At December 31, 2017, Ultra Resources was in compliance with all of its debt covenants under the Term Loan Facility.

The Term Loan Agreement contains customary events of default and remedies for credit facilities of this nature. If Ultra Resources does not comply with the financial and other covenants in the Term Loan Agreement, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Term Loan Agreement.

Senior Notes. On April 12, 2017, the Company issued $700.0 million of its 6.875% senior notes due 2022 (the “2022 Notes”) and $500.0 million of its 7.125% senior notes due 2025 (the “2025 Notes,” and together with the 2022 Notes, the “Notes”) and entered into an Indenture, dated April 12, 2017 (the “Indenture”), among Ultra Resources, as issuer, the Company and its subsidiaries, as guarantors. The Notes are treated as a single class of securities under the Indenture.

The Notes have not been registered under the Securities Act of 1933, as amended (the “Securities Act”) or any state securities laws, and unless so registered, the securities may not be offered or sold in the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. The Notes may be resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act or to non-U.S. persons pursuant to Regulation S under the Securities Act.

The 2022 Notes will mature on April 15, 2022. The interest payment dates for the 2022 Notes are April 15 and October 15 of each year. The 2025 Notes will mature on April 15, 2025. The interest payment dates for the 2025 Notes are April 15 and October 15 of each year. Interest will be paid on the Notes from the issue date until maturity.

Prior to April 15, 2019, Ultra Resources may, at any time or from time to time, redeem in the aggregate up to 35% of the aggregate principal amount of the 2022 Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 106.875% of the principal amount of the 2022 Notes, plus accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the original principal amount of the 2022 Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before April 15, 2019, Ultra Resources may redeem all or a part of the 2022 Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. In addition, on or after April 15, 2019, Ultra Resources may redeem all or a part of the 2022 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.438% for the twelve-month period beginning on April 15, 2019, 101.719% for the twelve-month period beginning April 15, 2020, and 100.000% for the twelve-month period beginning April 15, 2021 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2022 Notes.

Prior to April 15, 2020, Ultra Resources may, at any time or from time to time, redeem in the aggregate up to 35% of the aggregate principal amount of the 2025 Notes in an amount no greater than the net cash proceeds of certain equity offerings at a redemption price of 107.125% of the principal amount of the 2025 Notes, plus accrued and unpaid interest, if any, to the date of redemption, if at least 65% of the original principal amount of the 2025 Notes remains outstanding and the redemption occurs within 180 days of the closing of such equity offering. In addition, before April 15, 2020, Ultra Resources may redeem all or a part of the 2025 Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make-whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. In addition, on or after April 15, 2019, Ultra Resources may redeem all or a part of the 2025 Notes at redemption prices (expressed as percentages of principal amount) equal to 105.344% for the twelve-month period beginning on April 15, 2020, 103.563% for the twelve-month period beginning April 15, 2021, 101.781% for the twelve-month period beginning April 15, 2022, and 100.000% for the twelve-month period beginning April 15, 2023 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2025 Notes.

If Ultra Resources experiences certain change of control triggering events set forth in the Indenture, each holder of the Notes may require Ultra Resources to repurchase all or a portion of its Notes for cash at a price equal to 101% of the aggregate principal amount of such Notes, plus any accrued but unpaid interest to the date of repurchase.

The Indenture contains customary covenants that restrict the ability of Ultra Resources and the guarantors and certain of its subsidiaries to: (i) sell assets and subsidiary equity; (ii) incur indebtedness; (iii) create or incur certain liens; (iv) enter into affiliate agreements; (v) enter into agreements that restrict distribution from certain restricted subsidiaries and the consummation of mergers and consolidations; (vi) consolidate, merge or transfer all or substantially all of the assets of the Company or any Restricted Subsidiary (as defined in the Indenture); and (vii) create unrestricted subsidiaries. The covenants in the Indenture are subject to important exceptions and qualifications. Subject to conditions, the Indenture provides that the Company and its subsidiaries will no longer be subject to certain covenants when the Notes receive investment grade ratings from any two of S&P Global Ratings, Moody's Investors Service, Inc., and Fitch Ratings, Inc. At December 31, 2017, Ultra Resources was in compliance with all of its debt covenants under the Notes.

The Indenture contains customary events of default (each, an "Event of Default"). Unless otherwise noted in the Indenture, upon a continuing Event of Default, the trustee under the Indenture ("the Trustee"), by notice to the Company, or the holders of at least 25% in principal amount of the then outstanding Notes, by notice to the Company and the Trustee, may, declare the Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Company, any Significant Subsidiary (as defined in the Indenture) or group of Restricted Subsidiaries (as defined in the Indenture), that taken together would constitute a Significant Subsidiary, will automatically cause the Notes to become due and payable.

Other long-term obligations: These costs primarily relate to the long-term portion of production taxes payable and asset retirement obligations.

6. SHARE BASED COMPENSATION:

The Company sponsors a share based compensation plan: the 2017 Stock Incentive Plan ("2017 Plan"). The Plan is administered by the Compensation Committee of the Board of Directors (the "Committee"). The share based compensation plan is an important component of the total compensation package offered to the Company's key service providers, and reflects the importance that the Company places on motivating and rewarding superior results.

The 2017 Plan was established on the Effective Date, pursuant to which 7.5% of the equity in the reorganized Company (on a fully-diluted/fully-distributed basis) is reserved for grants to be made from time to time to the directors, officers, and other employees of the reorganized Company (the "Reserve").

Valuation and Expense Information

	Year Ended December 31,		
	2017	2016	2015
Total cost of share-based payment plans	$ 53,952	$ 8,013	$ 6,137
Amounts capitalized in oil and gas properties and equipment	$ 13,975	$ 2,451	$ 2,009
Amounts charged against income, before income tax benefit	$ 39,977	$ 5,562	$ 4,128
Amount of related income tax benefit recognized in income before valuation allowances	$ 15,927	$ 2,216	$ 1,645

Securities Authorized for Issuance Under Equity Compensation Plans

As of December 31, 2017, the Company had the following securities issuable pursuant to outstanding award agreements or reserved for issuance under the Company's previously approved stock incentive plans. Upon exercise, shares issued will be newly issued shares or shares issued from treasury.

Plan Category	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (000's)
Equity compensation plans approved by security holders	14,457
Equity compensation plans not approved by security holders	n/a
Total	14,457

Changes in Stock Options and Stock Options Outstanding

As provided in the Plan, all plans or programs calling for stock grants, stock issuances, stock reserves, or stock options were cancelled as of the Effective Date and all outstanding awards established prior to the Effective Date were cancelled and extinguished as of the Effective Date.

PERFORMANCE SHARE PLANS:

2017 Stock Incentive Plan. As mentioned above, the 2017 Stock Incentive Plan was established on the Effective Date which stated that 7.5% of the equity of the reorganized Company is reserved for grants to be made to directors, officers, and other employees of the Company. Also on the Effective Date, 40% of the Reserve, ("Initial MIP Grants") was granted to members of the board of directors, officers, and other employees of the reorganized Company subject to the conditions and performance requirements provided in the grants, including the limitations that one-third of the Initial MIP Grants will vest, if at all, at such time when the total enterprise value of the Company equals or exceeds $6.0 billion based upon the weighted average price of the common stock during a consecutive 30-day period, that one-third of the Initial MIP Grants will vest, if at all, at such time when the total enterprise value of the Company equals or exceeds 110% of $6.0 billion based upon the volume weighted average price of the common stock during a consecutive 30-day period, and that if any Initial MIP Grants do not vest before the fifth anniversary of the Effective Date, such Initial MIP Grants shall automatically expire.

Long Term Incentive Plans. Subsequent to December 31, 2017, the Board approved the establishment of a Long Term Incentive Plan ("LTIP") in order to further align the interests of key employees with shareholders and to give key employees the opportunity to share in the long-term performance of the Company when specific corporate financial and operational goals are achieved. The LTIP established covers a performance period of three years and includes time-based and performance-based measures established by the Committee at the beginning of the three-year period.

Stock-Based Compensation Cost:

Modification. On the Effective Date, as provided in the Plan, all outstanding awards established prior to the Effective Date were cancelled and extinguished, and participants received no payment or other distribution on account of the outstanding awards. Under FASB ASC Topic 718, Compensation Cost – Stock Compensation ("FASB ASC 718"), the cancellation of an outstanding award of stock based compensation followed by the issuance of a replacement award is treated as a modification of the original award. The equity award cancellations and subsequent new grants by the Company were considered Type I, probable to probable modification. This type represents modifications where the award was likely to vest prior to modification and is still likely to vest after modification. For these types of modifications, the fair value of the award is assessed both prior to modification and after modification. If the fair value after modification exceeds the fair value prior to modification, incremental expense is generated and recognized over the remaining vesting period

Market Based Conditions. When vesting of an award of stock-based compensation is dependent, at least in part, on the value of a company's total equity, for purposes of FASB ASC 718, the award is considered to be subject to a "market condition". Because the Company's total equity value is a component of its enterprise value, the awards based on enterprise value are considered to be subject to a market condition. Unlike the valuation of an award that is subject to a service condition (i.e., time vested awards) or a performance condition that is not related to stock price, FASB ASC 718 requires the impact of the market condition to be considered when estimating the fair value of the award. As a result, we have used a Monte Carlo simulation model to estimate the fair value of the awards that include a market condition.

FASB ASC 718 requires the expense for an award of stock based compensation that is subject to a market condition that can be attained at any point during the performance period to be recognized over the shorter of (a) the period between the date of grant and the date the market condition is attained, and (b) award's derived service period. For purposes of FASB ASC 718, the derived service period represents the duration of the median of the distribution of share price paths on which the market condition is satisfied. That median is the middle share price path (the midpoint of the distribution of paths) on which the market condition is satisfied. The duration is the period of time from the service inception date to the expected date of market condition satisfaction. Compensation expense is recognized regardless of whether the market condition is actually satisfied.

Expense. For the year ended December 31, 2017, the Company recognized $40.0 million in pre-tax compensation expense, of which $38.5 million related to the Initial MIP Grants. For the year ended December 31, 2016, the Company recognized $5.6 million in pre-tax compensation expense, of which $4.7 million related to the 2015 and 2014 LTIP awards. For the year ended December 31, 2015, the Company recognized $4.1 million in pre-tax compensation expense, of which $2.9 million related to the 2015, 2014 and 2013 LTIP awards. The Company expects the total expense associated with the portion of the Initial MIP Grants that vests if the $6.0 billion total enterprise value performance requirement is satisfied to be $21.3 million and the portion of the Initial MIP grants that vests if the $6.6 billion total enterprise value performance requirement is satisfied to be $20.1 million, respectively. One-third of the Initial MIP Grants were paid in shares of the Company's stock to members of its board of directors, as well as its officers and other employees on the Effective Date and totaled $26.1 million (1,238,665 shares) of which a portion was capitalized into oil and gas properties as noted in the valuation and expense information above.

7. DERIVATIVE FINANCIAL INSTRUMENTS:

Objectives and Strategy: The Company's major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company's natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company's forward cash flows supporting the Company's capital investment program. These types of instruments may include fixed price swaps, costless collars, or basis differential swaps. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. While mitigating the effects of fluctuating commodity prices, these derivative contracts may limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

The Company's hedging policy limits the amounts of resources hedged to not more than 50% of its forecasted production volumes without Board approval.

Fair Value of Commodity Derivatives: FASB ASC 815 requires that all derivatives be recognized on the balance sheet as either an asset or liability and be measured at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The Company does not apply hedge accounting to any of its derivative instruments.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value on the Consolidated Balance Sheets and the associated unrealized gains and losses are recorded as current expense or income in the Consolidated Statements of Operations. Unrealized gains or losses on commodity derivatives represent the non-cash change in the fair value of these derivative instruments and do not impact operating cash flows on the Consolidated Statements of Cash Flows.

Commodity Derivative Contracts: At December 31, 2017, the Company had the following open commodity derivative contracts to manage commodity price risk. For the fixed price swaps, the Company receives the fixed price for the contract and pays the variable to the counterparty. For the collars, the Company pays the counterparty if the market price is above the ceiling price and the counterparty pays if the market price is below the floor on a notional quantity. The reference prices of these commodity derivative contracts are typically referenced to index prices published by independent third parties.

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Average Price/MMBTU	Fair Value - December 31, 2017
Natural Gas					Asset (Liability)
Fixed price swaps					
	NYMEX-Henry Hub	April-Oct 2018	380,000	$ 2.97	$ 15,419

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Floor Price ($/MMBTU)	Ceiling Price ($/MMBTU)	Fair Value - December 31, 2017
Collars						
	NYMEX-Henry Hub	Jan-Mar 2018	40,000	$ 3.23	$ 3.54	$ 1,446

Subsequent to December 31, 2017 and through February 15, 2018, the Company has entered into the following open commodity derivative contracts to manage commodity price risk.

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Average Price/MMBTU
Natural Gas				
Fixed price swaps	NYMEX-Henry Hub	April-Oct 2018	390,000	$ 2.79
	NYMEX-Henry Hub	Nov-Dec 2018	400,000	$ 2.88
	NYMEX-Henry Hub	Jan-Mar 2019	200,000	$ 2.91

Type	Commodity Reference Price	Remaining Contract Period	Volume/ MMBTU/day	Average Differential/MMBTU
Natural Gas				
Basis Swap Contracts(1)				
	NW Rockies Basis Swap	Mar-Dec 2018	30,000	$ (0.58)
	NW Rockies Basis Swap	April-Oct 2018	140,000	$ (0.62)

Type	Commodity Reference Price	Remaining Contract Period	Volume/ Bbls/day	Average Price/Bbls
Crude Oil				
Fixed price swaps	NYMEX-WTI	Feb-Dec 2018	2,000	$ 62.17
	NYMEX-WTI	Mar-Dec 2018	2,000	$ 57.43

(1) Represents swap contracts that fix the basis differentials for gas sold at or near Opal, Wyoming and the value of natural gas established on the last trading day of the month by the NYMEX for natural gas swaps for the respective period.

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015:

Commodity Derivatives:	For the Year Ended December 31, 2017	2016	2015
Realized gain on commodity derivatives-natural gas (1)	$ 11,446	$ —	$ 146,801
Unrealized gain (loss) on commodity derivatives (1)	16,966	—	(104,190)
Total gain on commodity derivatives	$ 28,412	$ —	$ 42,611

(1) Included in gain on commodity derivatives in the Consolidated Statements of Operations.

8. FAIR VALUE MEASUREMENTS:

As required by FASB ASC Topic 820, Fair Value Measurements and Disclosures ("FASB ASC 820"), the Company defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and establishes a three-level hierarchy for measuring fair value. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions the Company has used to measure the fair value of its commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs).

	Level 1	Level 2	Level 3	Total
Assets:				
Current derivative asset	$ —	$ 16,865	$ —	$ 16,865

Assets and Liabilities Measured on a Non-Recurring Basis

The Company uses fair value to determine the value of its asset retirement obligations. The inputs used to determine such fair value under the expected present value technique are primarily based upon internal estimates prepared by reservoir engineers for costs of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and gas properties and would be classified Level 3 inputs.

Table of Contents

Fair Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the immediate or short-term maturity of these financial instruments. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates. We use available market data and valuation methodologies to estimate the fair value of our fixed rate debt and the fair values presented in the tables below reflect original maturity dates for each of the debt instruments. The inputs utilized to estimate the fair value of the Company's fixed rate debt are considered Level 2 fair value inputs. This disclosure is presented in accordance with FASB ASC Topic 825, Financial Instruments, and does not impact our financial position, results of operations or cash flows.

	December 31, 2017		December 31, 2016 (1)	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Term Loan, secured due 2024	$ 975,000	$ 975,000	$ —	$ —
6.875% Senior, unsecured Notes, due 2022	700,000	701,750	—	—
7.125% Senior, unsecured Notes, due 2025	500,000	505,000	—	—
Credit Agreement, secured	—	—	—	—
7.31% Notes due March 2016, issued 2009	—	—	62,000	64,266
4.98% Notes due January 2017, issued 2010	—	—	116,000	123,967
5.92% Notes due March 2018, issued 2008	—	—	200,000	224,025
5.75% Notes due December 2018, issued 2013	—	—	450,000	465,630
7.77% Notes due March 2019, issued 2009	—	—	173,000	204,854
5.50% Notes due January 2020, issued 2010	—	—	207,000	233,932
4.51% Notes due October 2020, issued 2010	—	—	315,000	337,528
5.60% Notes due January 2022, issued 2010	—	—	87,000	99,983
4.66% Notes due October 2022, issued 2010	—	—	35,000	38,225
6.125% Notes due October 2024, issued 2014	—	—	850,000	893,325
5.85% Notes due January 2025, issued 2010	—	—	90,000	106,299
4.91% Notes due October 2025, issued 2010	—	—	175,000	193,665
Credit Facility due October 2016	—	—	999,000	999,000
	$ 2,175,000	$ 2,181,750	$ 3,759,000	$ 3,984,699

(1) At December 31, 2016, the debt included in the table above is a component of liabilities subject to compromise in our Consolidated Balance Sheets. See Note 1.

9. INCOME TAXES:

Income (loss) before income tax benefit is as follows:

	Year Ended December 31,		
	2017	2016	2015
United States	$ (197,136)	$ 134,959	$ (3,249,590)
Foreign	360,982	(79,462)	37,966
Total	$ 163,846	$ 55,497	$ (3,211,624)

The consolidated income tax (benefit) provision is comprised of the following:

	Year Ended December 31,		
	2017	2016	2015
Current tax:			
U.S. federal, state and local	$ (13,296)	$ (72)	$ —
Foreign	2	(583)	(3,414)
Total current tax (benefit)	(13,294)	(655)	(3,414)
Deferred tax:			
Foreign	—	1	(990)
Total deferred tax (benefit) expense	—	1	(990)
Total income tax (benefit)	$ (13,294)	$ (654)	$ (4,404)

The income tax provision (benefit) from continuing operations differs from the amount that would be computed by applying the U.S. federal income tax rate of 35% to pretax income as a result of the following:

	Year Ended December 31,		
	2017	2016	2015
Income tax provision (benefit) computed at the U.S. statutory rate	$ 57,346	$ 19,424	$ (1,124,069)
State income tax (benefit) provision net of federal effect	(25,519)	(2,335)	(12,998)
Valuation allowance	(562,491)	(31,083)	1,147,619
Tax effect of rate change	463,113	—	12,898
Sale of Pennsylvania assets	130,552	—	0
Foreign rate differential	(3,150)	17,388	(26,740)
Reorganization items	(78,549)	—	—
Other, net	5,404	(4,048)	(1,114)
Total income tax (benefit)	$ (13,294)	$ (654)	$ (4,404)

The tax effects of temporary differences that give rise to significant components of the Company's deferred tax assets and liabilities are as follows:

	December 31,	
	2017	2016
Deferred tax assets:		
Property and equipment	181,524	603,045
Deferred gain	22,256	40,867
U.S. federal tax credit carryforwards	987	15,967
U.S. net operating loss carryforwards	450,623	428,212
U.S. state net operating loss carryforwards	4,038	71,323
Non-U.S. net operating loss carryforwards	6,556	30,211
Asset retirement obligations	36,624	55,700
Liabilities subject to compromise-contract settlement	—	59,166
Incentive compensation/other, net	8,308	16,088
	710,916	1,320,579
Valuation allowance	(707,348)	(1,270,935)
Net deferred tax assets	$ 3,568	$ 49,644
Deferred tax liabilities:		
Derivative instruments, net	3,568	—
Liabilities subject to compromise-interest	—	35,498
Liabilities subject to compromise-interest (non-U.S.)	—	14,146
Other — non-US	—	—
Net tax liabilities	$ 3,568	$ 49,644
Net tax asset	$ —	$ —

In assessing the realizability of the deferred tax assets, management considers whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which the temporary differences become deductible or before the attributes expire unused. Among other items, management considers the scheduled reversal of deferred tax liabilities, historical taxable income, projected future taxable income, and available tax planning strategies.

At December 31, 2017 and 2016, the Company recorded a valuation allowance against certain deferred tax assets of $0.7 billion and $1.3 billion, respectively. Some or all of this valuation allowance may be reversed in future periods if future taxable income of the appropriate character is available to recognize certain deferred tax assets.

The Company has a U.S. federal tax net operating loss carryforward of $2.1 billion which will be carried forward to offset taxable income generated in future years, and if unutilized, will expire between 2033 and 2037. The Company has Utah state tax net operating loss carry forwards of $102.2 million which will expire between 2033 and 2037. The Company has immaterial Canadian Federal and Provincial and U.S. State tax net operating loss carry forwards in which minimal or no oil and gas operations exist. The ownership change that occurred as a result of the Company's chapter 11 restructuring did not significantly impair the ability to utilize the net operating loss carryforwards to offset future taxable income. Without regard to the recorded valuation allowance, if the Company experiences an additional ownership change as determined under Section 382 of the Internal Revenue Code, our ability to utilize our substantial net operating loss carryforwards and other tax attributes may be limited, if we can use them at all.

The Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations related to accounting for uncertain tax positions. The amount of unrecognized tax benefits did not change as of December 31, 2017.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statements of Operations. The Company has not incurred any interest or penalties associated with unrecognized tax benefits.

The Company files a consolidated federal income tax return in the United States federal jurisdiction and various combined, consolidated, unitary, and separate filings in several states, and international jurisdictions. With certain exceptions, the income tax years 2014 through 2017 remain open to examination by the major taxing jurisdictions in which the Company has business activity. The Company has been notified that Canada intends to audit tax years 2015 and 2016. Management does not expect the results of the audit to materially impact the Company's financial statements.

The undistributed earnings of the Company's U.S. subsidiaries are considered to be indefinitely invested outside of Canada. It is not practical to estimate the amount of unrecognized deferred tax liability related to undistributed foreign earnings at this time. No provision for Canadian income taxes and/or withholding taxes has been provided thereon.

On December 22, 2017, the Tax Cuts and Jobs Act ("TCJA") was enacted into law. The new legislation decreases the U.S. corporate federal income tax rate from 35% to 21% effective January 1, 2018. The Company does not expect any impact on recorded deferred tax balances as the re-measurement of net deferred tax assets will be offset by a change in the valuation allowance. The Act also includes a number of other provisions including the elimination of loss carrybacks and limitations on the use of future losses, repeal of the Alternative Minimum Tax regime, the limitation on the deductibility of certain expenses, including interest expense, and changes in the way capital costs are recovered. These provisions are not expected to have an immediate effect on the Company. TCJA did not make significant changes to the Company's ability to deduct intangible development costs or depletion. The Company's significant net operating loss carryforwards generated in 2017 and before are grandfathered under the provisions of TCJA and should not be subject to the limitations imposed by the act. Further, the elimination of the Alternative Minimum Tax is beneficial because it allows the Company to recover its AMT credit carryforwards in 2018 through 2021. The amount of this expected benefit has been recorded in the financial statements as of and for the year ended December 31, 2017.

Given the significant complexity of the TCJA and anticipated additional implementation guidance from the Internal Revenue Service, the remeasurement is considered provisional, and further implications of the TCJA may be identified in future periods.

10. EMPLOYEE BENEFITS:

The Company sponsors a qualified, tax-deferred savings plan in accordance with provisions of Section 401(k) of the Internal Revenue Code for its employees. Employees may defer 100% of their compensation, subject to limitations. The Company matches all of the employee's contribution up to 5% of compensation, as defined by the plan, along with an employer discretionary contribution of 8%. The expense associated with the Company's contribution was $2.4 million, $2.3 million and $2.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

11. COMMITMENTS AND CONTINGENCIES:

The Plan provides for the treatment of claims against our bankruptcy estates, including claims for prepetition liabilities that have not otherwise been satisfied or addressed before we emerged from chapter 11 proceedings. As noted in this Annual Report on Form 10-K, the claims resolution process associated with chapter 11 proceedings is on-going, and we expect it to continue for an indefinite period of time.

Indebtedness Claims

Our chapter 11 filings constituted events of default under Ultra Resources' prepetition debt agreements. During our bankruptcy proceedings, many holders of this indebtedness filed proofs of claim with the Bankruptcy Court, asserting claims for the outstanding balance of the indebtedness, unpaid prepetition interest dates, unpaid post-petition interest (including interest at the default rates under the debt agreements), make-whole amounts, and other fees and obligations allegedly arising under the debt agreements. As previously disclosed, in connection with our emergence from bankruptcy and in accordance with the Plan, all of our obligations with respect to Ultra Resources prepetition indebtedness and the associated debt agreements were cancelled, except to the limited extent expressly set forth in the Plan, and the holders of claims related to the indebtedness received payment in full of allowed claims (including with respect to outstanding principal, unpaid prepetition interest, and certain other prepetition fees and obligations arising under the debt agreements). In connection with the confirmation and consummation of the Plan, we entered into a stipulation with the claimants pursuant to which we agreed to establish and fund a $400.0 million reserve account after the Effective Date, pending resolution of make-whole and postpetition interest claims. On April 14, 2017, we funded the account. Following our emergence from bankruptcy, we continued to dispute the claims made by holders of the Ultra Resources' indebtedness for certain make-whole amounts and post-petition interest at the default rates provided for in the debt agreements.

On September 22, 2017, the Bankruptcy Court denied the Company's objection to the pending make-whole and postpetition interest claims. On October 6, 2017, the Bankruptcy Court entered an order requiring the Company to distribute amounts attributable to the disputed claims to the applicable parties. Pursuant to the order, on October 12, 2017, $399.0 million was distributed from the Reserve Fund to the parties asserting the make-whole and postpetition interest claims and $1.3 million (the balance remaining after distributions to the parties asserting claims) was returned to the Company. The disbursement of $399.0 million was comprised of $223.8 million representing the fees owed under the make-whole claims described above, which are included in reorganization items in the Consolidated Statements of Operations and $175.2 million representing the postpetition interest at the default rate, as described above, which is included in interest expense in the Consolidated Statements of Operations. The Company is appealing the court order denying its objections to these claims, but it is not possible to determine the ultimate disposition of these matters at this time.

Royalties

On April 19, 2016, the Company received a preliminary determination notice from the Office of Natural Resources Revenue ("ONRR") asserting that the Company's allocation of certain processing costs and plant fuel use at certain processing plants were impermissibly charged as deductions in the determination of royalties owed under Federal oil and gas leases. ONRR also filed a proof of claim in our bankruptcy proceedings asserting approximately $35.1 million in claims related to these matters. We dispute the preliminary determination and the proof of claim. We have notified ONRR of several matters we believe ONRR may not have considered in preparing the preliminary determination notice, and we continue to be in discussions with ONRR related to these matters. This claim and the preliminary determination notice could ultimately result in us being ordered to pay additional royalty to ONRR for prior, current, and future periods. The Company is not able to determine the likelihood or range of any additional royalties or, if and when assessed, whether such amounts would be material.

Oil Sales Contract

On April 29, 2016, the Company received a letter from counsel to Sunoco Partners Marketing & Terminals L.P. ("SPMT") asserting that (1) the Company had breached, by anticipatory repudiation, a contract for the purchase and sale of crude oil between Ultra Resources and SPMT and (2) the contract was terminated. In the letter, SPMT demanded payment for damages resulting from the breach in the amount of $38.6 million. On August 31, 2016, SPMT filed a proof of claim with the Bankruptcy Court for $16.9 million. On December 13, 2016, we filed an objection to SPMT's proof of claim, and on December 14, 2016, we filed an adversary proceeding against SPMT related to matters we believe constitute breach of the contract by SPMT during the prepetition period (as amended, the "Sunoco Adversary"). In its April 25, 2017 reply to the Sunoco Adversary complaint, Sunoco asserted a counterclaim for matters addressed in its proof of claim. Litigation related to this matter is proceeding in the Bankruptcy Court. At this time, we are not able to determine the likelihood or range of damages owed by or to SPMT, if any, related to this matter, or, if and when such amounts are assessed, whether such amounts would be material.

Operating Lease

During December 2012, the Company sold a system of pipelines and central gathering facilities (the "Pinedale LGS") and certain associated real property rights in the Pinedale Anticline in Wyoming and entered into a long-term, triple net lease agreement (the "Pinedale Lease Agreement") relating to the use of the Pinedale LGS. The Pinedale Lease Agreement provides for an initial term of 15 years and potential successive renewal terms of 5 years or 75% of the then remaining useful life of the Pinedale LGS at the sole discretion of the Company. Annual rent for the initial term under the Pinedale Lease Agreement is $20.0 million (as adjusted annually for changes based on the consumer price index) and may increase if certain volume thresholds are exceeded. The lease is classified as an operating lease. The Company currently projects that lease payments related to the Pinedale Lease Agreement will total approximately $213.2 million.

All of the Company's lease obligations are related to leases that are classified as operating leases. These leases contain certain provisions that could result in accelerated lease payments. The Company has considered the effect of these provisions on minimum lease payments in its lease classification analysis and has determined that the default provisions do not impact classification of any the Company's operating leases.

Office space lease

The Company maintains office space in Colorado, Texas, Wyoming and Utah with total remaining commitments for office leases of $5.7 million at December 31, 2017; ($1.4 million in 2018; $1.3 million in 2019; $1.3 million in 2020; $1.1 million in 2021; and $0.6 million in 2022 with the remainder due beyond five years).

During the years ended December 31, 2017, 2016 and 2015, the Company recognized expense associated with its office leases in the amount of $1.6 million, $1.5 million, and $1.3 million, respectively.

Delivery Commitments

With respect to the Company's natural gas production, from time to time the Company enters into transactions to deliver specified quantities of gas to its customers. As of February 9, 2018, the Company has long-term natural gas delivery commitments of 12.6 MMMBtu in 2019 under existing agreements. As of February 9, 2018, the Company has long-term crude oil delivery commitments of 1.7 MMBbls in 2018 and 0.3 MMBbls in 2019 under existing agreements. None of these commitments require the Company to deliver gas or oil produced specifically from any of the Company's properties, and all of these commitments are priced on a floating basis with reference to an index price. In addition, none of the Company's reserves are subject to any priorities or curtailments that may affect quantities delivered to its customers, any priority allocations or price limitations imposed by federal or state regulatory agencies or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Item 1A. "Risk Factors". If for some reason our production is not sufficient to satisfy these commitments, subject to the availability of capital, we could purchase volumes in the market or make other arrangements to satisfy the commitments.

Other Claims

The Company is party to disputes with respect to overriding royalty interests in certain of our operated leases in Pinedale, Wyoming. At this time, no determination of the outcome of these claims can be made, and as no damage claim amount has been asserted by the claimants, we cannot reasonably estimate the potential impact of these claims. We are defending these cases vigorously, and expect these claims to be resolved in our chapter 11 proceedings. The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company's financial position or results of operations.

12. CONCENTRATION OF CREDIT RISK:

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and commodity derivative contracts associated with the Company's hedging program. The Company's revenues related to natural gas and oil sales are derived principally from a diverse group of companies, including major energy companies, natural gas utilities, oil refiners, pipeline companies, local distribution companies, financial institutions and end-users in various industries.

Concentrations of credit risk with respect to receivables is limited due to the large number of customers and their dispersion across geographic areas. Commodity-based contracts may expose the Company to the credit risk of nonperformance by the counterparty to these contracts. This credit exposure to the Company is diversified primarily among as many as ten major investment grade institutions and will only be present if the reference price of natural gas established in those contracts is less than the prevailing market price of natural gas, from time to time.

The Company maintains credit policies intended to monitor and mitigate the risk of uncollectible accounts receivable related to the sale of natural gas, condensate as well as its commodity derivative positions. The Company performs a credit analysis of each of its customers and counterparties prior to making any sales to new customers or extending additional credit to existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. The Company did not have any outstanding, uncollectible accounts for its natural gas or oil sales, nor derivative settlements at December 31, 2017.

A significant counterparty is defined as one that individually accounts for 10% or more of the Company's total revenues during the year. In 2017, the Company had no single customer that represented more than 10% of its total revenues.

13. SUBSEQUENT EVENTS:

The Company has evaluated the period subsequent to December 31, 2017 for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose that should be disclosed in order to keep the financial statements from being misleading, except as set forth below:

Leadership Changes

On January 30, 2018, the Company announced the retirement of Mr. Michael D. Watford from his roles as President, Chief Executive Officer and Chairman of the Board of Directors of the Company, effective February 28, 2018. The Company concurrently announced the appointment of Brad Johnson, who has served the Company as Senior Vice President, Operations since April 2014, as interim Chief Executive Officer and a director of the Board effective February 28, 2018. The Board has not approved and the Company has not entered into any new compensation arrangements with Mr. Johnson as of the date of this Annual Report on Form 10-K.

On January 30, 2018, the Company also announced that, pursuant to the Cooperation Agreement described below, effective February 28, 2018, Dr. W. Charles Helton and Mr. Roger A. Brown will resign from their positions on the Board and that Evan Lederman, an investment professional with Fir Tree Capital Management LP (“Fir Tree”), and another individual to be selected and identified based on the terms and conditions of the Cooperation Agreement (collectively, the “New Directors”) would be appointed to the Board. No changes to the composition of committees of the Board or any compensation arrangements with the New Directors have been approved by the Board or entered into by the Company as of the date of this Annual Report on Form 10-K.

Cooperation Agreement with Fir Tree

On January 30, 2018, the Company entered into a Cooperation Agreement (the “Cooperation Agreement”) with Fir Tree Capital Management LP (“Fir Tree”) regarding the membership and composition of the Company’s Board of Directors and related matters. Pursuant to the Cooperation Agreement, effective February 28, 2018, the Company has appointed Mr. Lederman to the Board of Directors to fill the vacancy resulting from Dr. Helton’s resignation from the Board (as discussed above). In addition, the Company will also appoint the other New Director to the Board of Directors to fill the vacancy resulting from Mr. Brown’s resignation from the Board (as discussed above) once such individual has been selected and identified as contemplated in the Cooperation Agreement. Pursuant to the Cooperation Agreement, the Company has also agreed that Fir Tree may replace either New Director in the event either New Director resigns or can no longer serve on the Board due to death, disability or other reasons prior to the later of (x) April 12, 2019 and (y) the date on which such New Director is next up for election at a meeting of the Company’s shareholders, subject to such candidate meeting certain criteria as set forth in the Cooperation Agreement. In addition, pursuant to the Cooperation Agreement, Fir Tree has agreed to abide by certain standstill provisions during a standstill period (the “Standstill Period”) ending on the Standstill End Date. In the Cooperation Agreement, “Standstill End Date” means (i) if the Company shall have delivered to Fir Tree no later than thirty calendar days prior to the deadline for submission for nominations for election to the Board at the 2019 annual meeting of shareholders a written confirmation that the New Directors (or their respective replacements or proposed replacements) will be nominated for election to the Board at the 2019 annual meeting of shareholders of the Company, the earlier of (a) fifteen calendar days prior to the deadline for submission of nominations for election to the Board at the 2020 annual meeting of shareholders of the Company pursuant to the Company’s Amended and Restated Bylaw No. 1 and (b) April 19, 2020; or (ii) if the Company shall have failed to deliver the written confirmation pursuant to clause (i) of this definition, the earlier of (c) fifteen calendar days prior to the deadline for submission for nominations for election to the Board at the 2019 annual meeting of shareholders of the Company and (d) April 19, 2019. Pursuant to the Cooperation Agreement, Fir Tree has agreed to vote its shares of the Company’s common stock in favor of the Company’s nominees and other proposals at each Annual Meeting during the Standstill Period, subject to certain limited exceptions set forth in the Cooperation Agreement.

Separation Agreement

In connection with his resignation from his positions as Chairman of the Board of Directors and President and Chief Executive Officer of the Company, Mr. Michael D. Watford and the Company entered into a Separation and Release Agreement (the “Separation Agreement”) dated and effective as of February 23, 2018. The release portion of the Separation Agreement will be executed by Mr. Watford and the Company following the conclusion of his employment with the Company on February 28, 2018, and will be fully effective on March 8th, 2018 provided that Mr. Watford does not revoke his acceptance thereof prior to such date. As set forth in and pursuant to the Separation Agreement, the Company will pay Mr. Watford the severance payments and benefits specified in the Employment Agreement dated as of November 6, 2017 between Mr. Watford and the Company, which was filed on November 9, 2017 as Exhibit 10.8 to the Company’s Quarterly Report on Form 10-Q for its quarter ended September 30, 2017. These payments and benefits are comprised of certain accrued amounts, including Mr. Watford’s base salary through February 28, 2018, a cash severance payment in the amount of $3,762,950, and the vesting and delivery of 1,226,102 shares of common stock in the Company. In addition, the Company will make available to Mr. Watford, at the Company’s expense, continued participation in the Company’s welfare benefits plans, including disability, life and health insurance for a period of up to 24 months following February 28, 2018.

The foregoing description of the Separation Agreement is a summary, is not complete and is qualified in its entirety by reference to the Separation Agreement, which is filed as Exhibit 10.16 to this Annual Report on Form 10-K.

Table of Contents

14. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED):

	2017				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	$ 220,958	$ 212,657	$ 217,631	$ 240,627	$ 891,873
Gain (loss) on commodity derivatives	(13,218)	20,717	4,650	16,263	28,412
Operating expenses	104,227	134,393	122,394	132,574	493,588
Other income (expense), net:					
Interest expense	(85,447)	(29,425)	(210,107)	(36,388)	(361,367)
Contract settlement	(52,707)	—	—	—	(52,707)
Other income (expense), net	2,491	2,665	2,730	2,430	10,316
Total other (expense) income, net	(135,663)	(26,760)	(207,377)	(33,958)	(403,758)
Reorganization items, net	(57,546)	426,816	(227,123)	(1,240)	140,907
Income (loss) before income tax provision (benefit)	(89,696)	499,037	(334,613)	89,118	163,846
Income tax provision (benefit)	2	—	(6,886)	(6,410)	(13,294)
Net (loss) income	$ (89,698)	$ 499,037	$ (327,727)	$ 95,528	$ 177,140
Net income (loss) per common share — basic	$ (1.12)	$ 2.76	$ (1.67)	$ 0.49	$ 1.08
Net income (loss) per common share — fully diluted	$ (1.12)	$ 2.76	$ (1.67)	$ 0.49	$ 1.08

	2016				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
Operating revenues	$ 159,386	$ 146,591	$ 199,253	$ 215,861	$ 721,091
Operating expenses	126,868	94,746	99,788	99,313	420,715
Other income (expense), net:					
Interest expense (excludes contractual interest expense of $141.5 million for the year ended December 31, 2016)	(49,903)	(16,662)	—	—	(66,565)
Restructuring expenses	(5,579)	(1,569)	(28)	—	(7,176)
Contract settlement	—	—	—	(131,106)	(131,106)
Other income (expense), net	943	2,411	2,124	1,993	7,471
Total other (expense) income, net	(54,539)	(15,820)	2,096	(129,113)	(197,376)
Reorganization items, net	—	(22,183)	(3,109)	(22,211)	(47,503)
Income (loss) before income tax (benefit) provision	(22,021)	13,842	98,452	(34,776)	55,497
Income tax (benefit) provision	(190)	(160)	45	(349)	(654)
Net (loss) income	$ (21,831)	$ 14,002	$ 98,407	$ (34,427)	$ 56,151
Net income (loss) per common share — basic	$ (0.27)	$ 0.18	$ 1.23	$ (0.43)	$ 0.70
Net income (loss) per common share — fully diluted	$ (0.27)	$ 0.17	$ 1.22	$ (0.43)	$ 0.70

15. DISCLOSURE ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

The following information about the Company's oil and natural gas producing activities is presented in accordance with FASB ASC Topic 932, Oil and Gas Reserve Estimation and Disclosures:

A. OIL AND GAS RESERVES:

Our policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. The Senior Director — Development is primarily responsible for overseeing the preparation of the Company's reserve estimates. He has a Bachelor of Science degree in Petroleum Engineering and is a licensed Professional Engineer with over 15 years of experience. The Company's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

The estimates of proved reserves and future net revenue as of December 31, 2017, are based upon the use of technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The reserves were estimated using deterministic methods; these estimates were prepared in accordance with generally accepted petroleum engineering and evaluation principles. Standard engineering and geoscience methods, such as reservoir modeling, performance analysis, volumetric analysis and analogy, that were considered to be appropriate and necessary to establish reserve quantities and reserve categorization that conform to SEC definitions and rules and regulations, were also used. As in all aspects of oil and natural gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, these estimates necessarily represent only informed professional judgment.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. From time to time, the Company may adjust the inventory and schedule of its proved undeveloped locations in response to changes in capital budget, economics, new opportunities in the portfolio or resource availability. The Company has not scheduled any proved undeveloped reserves beyond five years nor does it have any proved undeveloped locations that have been part of its inventory of proved undeveloped locations for over five years.

The Company engaged Netherland, Sewell & Associates, Inc. ("NSAI"), a third-party, independent engineering firm, to prepare the reserve estimates for all of the Company's assets for the year ended December 31, 2017, 2016 and 2015 in this annual report.

Our internal professional staff works closely with our independent engineers, NSAI, to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves. The report of NSAI is included as an Exhibit to this annual report.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Sean A. Martin and Mr. Philip R. Hodgson. Mr. Martin, a Licensed Professional Engineer in the State of Texas (No. 125354), has been practicing consulting petroleum engineering at NSAI since 2014 and has over 7 years of prior industry experience. He graduated from graduated from University of Florida in 2007 with a Bachelor of Science Degree in Chemical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. Both technical principals meet or exceed 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; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Since January 1, 2016, no crude oil, natural gas or NGL reserve information has been filed with, or included in any report to, any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the U.S. Department of Energy. We file Form 23, including reserve and other information, with the EIA.

The following unaudited tables as of December 31, 2017, 2016 and 2015 reflect estimated quantities of proved oil and natural gas reserves for the Company and the changes in total proved reserves as of December 31, 2017, 2016 and 2015. All such reserves are located in the Green River Basin in Wyoming and the Uinta Basin in Utah for the year ended December 31, 2017 and in Green River Basin in Wyoming, the Appalachian Basin in Pennsylvania and the Uinta Basin in Utah for the years ended December 31, 2016 and 2015.

Table of Contents

B. ANALYSES OF CHANGES IN PROVEN RESERVES:

	United States		
	Oil (MBbls)	**Natural Gas (MMcf)**	**NGLs (MBbls)**
Reserves, December 31, 2014	67,766	4,831,194	21,993
Extensions, discoveries and additions	166	17,415	3
Sales	—	—	—
Acquisitions	—	—	—
Production	(3,533)	(268,954)	—
Revisions	(42,224)	(2,243,375)	(12,156)
Reserves, December 31, 2015	22,175	2,336,280	9,840
Extensions, discoveries and additions	3,519	251,634	530
Sales	—	—	—
Acquisitions	—	—	—
Production	(2,912)	(264,278)	—
Revisions	(1,307)	(2,023)	(467)
Reserves, December 31, 2016	21,475	2,321,613	9,903
Extensions, discoveries and additions	1,117	50,312	—
Sales	—	(89,315)	—
Acquisitions	153	22,400	—
Production	(2,775)	(260,009)	—
Revisions	7,148	910,991	(9,832)
Reserves, December 31, 2017	27,118	2,955,992	71

	United States		
	Oil (MBbls)	**Natural Gas (MMcf)**	**NGLs (MBbls)**
Proved:			
Developed	28,481	2,245,004	9,118
Undeveloped	39,285	2,586,190	12,875
Total Proved — 2014	67,766	4,831,194	21,993
Developed	22,175	2,336,280	9,840
Undeveloped	—	—	—
Total Proved — 2015	22,175	2,336,280	9,840
Developed	21,475	2,321,613	9,903
Undeveloped	—	—	—
Total Proved — 2016	21,475	2,321,613	9,903
Developed	21,652	2,261,289	71
Undeveloped	5,466	694,703	—
Total Proved — 2017	27,118	2,955,992	71

Changes in proved developed reserves: During 2017, substantially all of the changes were attributable to wells drilled in 2017.

Changes in proved undeveloped reserves: As of December 31, 2016 and 2015, the Company did not include PUD reserves in its total proved reserve estimates due to uncertainty regarding its ability to continue as a going concern and the availability of capital that would be required to develop the PUD reserves. Upon emergence from chapter 11 proceedings the Company began recognizing PUDs as the substantial doubt regarding the Company's ability to continue as a going concern had been alleviated. The changes to the Company's proved undeveloped reserves (PUDs) during 2017 include the addition of PUDs associated with the current development plan. As there were no PUDs recognized at December 31, 2016, there are no additions, transfers or conversions to record. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years. The Company annually reviews all PUDs to ensure an appropriate development plan exists.

Development plan: The development plan underlying the Company's proved undeveloped reserves, if any, adopted each year by senior management, is based on the best information available at the time of adoption. As factors such as commodity price, service costs, performance data, and asset mix are subject to change, the Company occasionally revises its development plan. Development plan revisions include deferrals, removals, and substitutions of previously scheduled PUD reserve locations. These occasional changes achieve the purpose of maximizing profitability and are in the best interest of the Company's shareholders.

NGLs: During 2014, the Company acquired contracts related to NGLs providing an annual election to process NGLs beginning in 2017. During 2017, the Company renegotiated its existing gas processing contracts in Wyoming. The new gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves.

C. STANDARDIZED MEASURE:

The following table sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved reserves. Natural gas prices have fluctuated widely in recent years. The calculated weighted average sales prices utilized for the purposes of estimating the Company's proved reserves and future net revenues at December 31, 2017, 2016 and 2015 was $2.59, $2.07 and $2.21 per Mcf, respectively, for natural gas, and $48.05, $37.90 and $42.36 per barrel, respectively, for oil and condensate. During 2014, the Company acquired contracts related to NGLs providing an annual election to process NGLs beginning in 2017. During 2017, the Company renegotiated its existing gas processing contracts in Wyoming. The new gas processing contracts are keep-whole contracts in which the Company shares in the economic benefit of processing and accordingly does not include the NGL volumes in its reserves. For 2016, and 2015 the average sales price utilized for purposes of estimating the Company's proved reserves and future net revenues associated with NGLs was $19.17 and $20.61 per barrel, respectively. The prices utilized in the reserve report are based upon the average of prices in effect on the first day of the month for the preceding twelve-month period.

The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved properties and available operating loss carryovers.

	As of December 31,		
	2017	2016	2015
Future cash inflows	$ 8,965,949	$ 5,812,234	$ 6,312,095
Future production costs	(3,587,581)	(2,665,082)	(3,006,265)
Future development costs	(1,001,024)	(355,923)	(358,848)
Future income taxes	—	—	—
Future net cash flows	4,377,344	2,791,229	2,946,982
Discount at 10%	(1,993,016)	(1,100,283)	(1,081,333)
Standardized measure of discounted future net cash flows	$ 2,384,328	$ 1,690,946	$ 1,865,649

The estimate of future income taxes is based on the future net cash flows from proved reserves adjusted for the tax basis of the oil and gas properties but without consideration of general and administrative and interest expenses.

D. *SUMMARY OF CHANGES IN THE STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS:*

	December 31, 2017	2016	2015
Standardized measure, beginning	$ 1,690,946	$ 1,865,649	$ 5,233,483
Net revisions of previous quantity estimates	840,505	(9,623)	(2,126,998)
Extensions, discoveries and other changes	53,549	209,603	15,254
Sales of reserves in place	(83,887)	—	—
Acquisition of reserves	21,903	—	—
Changes in future development costs	(329,635)	11,556	1,618,068
Sales of oil and gas, net of production costs	(589,621)	(454,725)	(550,879)
Net change in prices and production costs	572,224	(72,939)	(6,996,416)
Development costs incurred during the period that reduce future development costs	8,007	22,523	548,112
Accretion of discount	169,095	186,565	709,736
Net changes in production rates and other	31,242	(67,663)	1,551,413
Net change in income taxes	—	—	1,863,876
Aggregate changes	693,382	(174,703)	(3,367,834)
Standardized measure, ending	$ 2,384,328	$ 1,690,946	$ 1,865,649

There are numerous uncertainties inherent in estimating quantities of proved reserves and projected future rates of production and timing of development expenditures, including many factors beyond the control of the Company. The reserve data and standardized measures set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and 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, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and costs that may not prove correct over time. Predictions of future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Historically, oil and natural gas prices have fluctuated widely.

E. *COSTS INCURRED IN OIL AND GAS EXPLORATION AND DEVELOPMENT ACTIVITIES:*

	Years Ended December 31, 2017	2016	2015
United States			
Property Acquisitions:			
Unproved	$ 1,399	$ 983	$ 13,845
Proved	9,147	—	—
Exploration*	510,710	224,277	18,164
Development	35,934	44,300	461,458
Total	$ 557,190	$ 269,560	$ 493,467

* Exploration costs (as defined in Regulation S-X) includes costs spent on development of unproved reserves in the Pinedale Field.

F. *RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES:*

	Years Ended December 31, 2017	2016	2015
United States			
Oil and gas revenue	$ 891,873	$ 721,091	$ 839,111
Production expenses	(292,095)	(266,366)	(288,231)
Depletion and depreciation	(161,945)	(125,121)	(401,200)
Ceiling test and other impairments	—	—	(3,144,899)
Income tax benefit (expense)	(168,355)	83,112	(9,841)
Total	$ 269,478	$ 412,716	$ (3,005,060)

G. *CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES:*

	December 31, 2017	2016
Proven Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 11,215,563	$ 10,752,642
Less: accumulated depletion, depreciation and amortization	(9,890,495)	(9,742,176)
	$ 1,325,068	$ 1,010,466

16. SUPPLEMENTAL FINANCIAL STATEMENT INFORMATION:

Following are the financial statements of Ultra Petroleum Corp. (the "Parent Company"), which are included to provide additional information with respect to the Parent Company's results of operations, financial position and cash flows on a stand-alone basis:

CONDENSED STATEMENT OF OPERATIONS

	Year Ended December 31, 2017	2016	2015
General and administrative expense	$ 428	$ 650	$ 308
Other income (expense):			
Interest expense (excludes contractual interest expense of $52.4 million for the year ended December 31, 2016)	(71,876)	(26,590)	(81,069)
Income (loss) from unconsolidated affiliates	(183,840)	157,450	(3,152,078)
Guarantee fee income	—	6,073	23,029
Other expense	90	(64,888)	(1,684)
Reorganization items, net	433,196	(15,827)	—
Income (loss) before income taxes	177,142	55,568	(3,212,110)
Income tax provision (benefit)	2	(583)	(4,890)
Net income (loss)	$ 177,140	$ 56,151	$ (3,207,220)

Table of Contents

CONDENSED BALANCE SHEET

	December 31, 2017	December 31, 2016
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 803	$ 3,009
Accounts receivable from related companies	29,940	29,939
Other current assets	—	2,100
Total current assets	30,743	35,048
Other non-current assets	—	—
Total assets	$ 30,743	$ 35,048
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accrued and other current liabilities	$ 21	$ 47
Total current liabilities	21	47
Advances from unconsolidated affiliates	1,185,359	1,623,414
Total liabilities not subject to compromise	1,185,380	1,623,461
Liabilities subject to compromise	—	1,339,739
Total shareholders' deficit	(1,154,637)	(2,928,152)
Total liabilities and shareholders' equity	$ 30,743	$ 35,048

CONDENSED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
Net cash (used in) operating activities	$ (2,206)	$ (21,309)	$ (101,277)
Investing Activities:			
Investment in subsidiaries	(588,677)	—	—
Dividends received	—	24,089	96,297
Net cash (used in) provided by investing activities	(588,677)	24,089	96,297
Financing activities:			
Deferred financing costs	—	—	6
Shares issued	573,774	—	—
Repurchased shares/net share settlements	14,903	43	—
Shares re-issued from treasury	—	(337)	4,725
Net cash provided by (used in) financing activities	588,677	(294)	4,731
(Decrease) increase in cash during the period	(2,206)	2,486	(249)
Cash and cash equivalents, beginning of period	3,009	523	772
Cash and cash equivalents, end of period	$ 803	$ 3,009	$ 523

Item 9.*Change in and Disagreements with Accountants on Accounting and Financial Disclosures.*

None.

Item 9A.*Controls and Procedures.*

Management's Report on Internal Control Over Financial Reporting

Management's Report on Internal Control Over Financial Reporting is included on page 54 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Evaluation of Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) and Rule 15d-15(e) promulgated under the Exchange Act. Based on that evaluation, our chief executive officer and our chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2017, the end of the period covered by this report. The evaluation considered the procedures designed to ensure that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

Item 9B.*Other Information.*

As previously disclosed, on January 30, 2018, the Company announced the retirement of Michael D. Watford, the Company's President and Chief Executive Officer, from his roles at the Company, and his resignation from his role as Chairman of the Board, which such retirement and resignation will become effective as of the close of business on February 28, 2018. In connection with his retirement and resignation, Mr. Watford and the Company entered into a Separation and Release Agreement dated and effective as of February 23, 2018 (the "Separation Agreement"). The release portion of the Separation Agreement will be executed by Mr. Watford and the Company following the conclusion of his employment with the Company at the close of business on February 28, 2018, and will be fully effective on March 8, 2018, provided that Mr. Watford does not revoke his acceptance thereof prior to such date. Pursuant to the Separation Agreement, the Company will pay Mr. Watford the severance payments and benefits specified in the Employment Agreement dated as of November 6, 2017 between Mr. Watford and the Company, which was filed on November 9, 2017 as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017. These payments and benefits are comprised of certain accrued amounts, including Mr. Watford's base salary through February 28, 2018, a cash severance payment in the amount of approximately $3.76 million, and the vesting and delivery of 1,226,102 shares of our common stock. In addition, the Company will make available to Mr. Watford, at the Company's expense, continued participation in the Company's welfare benefits plans, including disability, life and health insurance for a period of up to 24 months following February 28, 2018. This summary of the Separation Agreement does not purport to be complete and is qualified in its entirety by reference to the full text of the Agreement, a copy of which is attached as Exhibit 10.17 hereto and is incorporated herein by reference.

As previously disclosed, on January 29, 2018, the Company entered into a Cooperation Agreement (the "Cooperation Agreement") with Fir Tree Capital Management LP ("Fir Tree") regarding the membership and composition of the Board and related matters, which was filed on January 30, 2018 as Exhibit 10.1 to the Company's Current Report on Form 8-K.

As contemplated in the Cooperation Agreement, each of the following events will occur and become effective upon the close of business on February 28, 2018: the resignation of Mr. Watford from his positions as the Company's President, Chief Executive Officer and Chairman of the Board; the appointment of Brad Johnson, the Company's Senior Vice President, Operations, to the position of interim Chief Executive Officer of the Company and as a director of the Board to fill the vacancy resulting from Mr. Watford's resignation from his position as a director of the Board; the resignation of Dr. Wm. Charles Helton from his position as the Lead Independent Director of the Board, as the chairman of the Company's Compensation Committee, and as a member of the Company's Audit Committee and Nominating and Corporate Governance Committee; the appointment of Evan S. Lederman, a Fir Tree investment professional, as a director of the Board to fill the vacancy resulting from Dr. Helton's resignation from the Board; the resignation of Roger A. Brown from his position as a director of the Board, as the chairman of the Company's Nominating and Corporate Governance Committee, and as a member of the Company's Audit Committee and Compensation Committee; the appointment of Edward Andrew Scoggins, Jr. as a director and independent member of the Board to fill the vacancy resulting from Mr. Brown's resignation from the Board. Messrs. Lederman and Scoggins will serve on the Board until the later of (i) April 12, 2019 and (ii) the date on which they are next up for election at the 2019 annual meeting of the Company's shareholders. Except as noted above with respect to the resignations of Dr. Helton and Mr. Brown, no changes to the composition of the Board committees nor any compensation arrangements with Messrs. Lederman or Scoggins were approved by the Board as of the date hereof.

Part III

Item 10.*Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated herein by reference to the Company’s definitive proxy statement, which will be filed not later than 120 days after December 31, 2017.

The Company has adopted a code of ethics that applies to the Company’s Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics is posted on the Company’s website at www.ultrapetroleum.com, and is available free of charge in print to any shareholder who requests it. Requests for copies should be addressed to the Secretary at 400 North Sam Houston Parkway East, Suite 1200, Houston, Texas 77060.

Item 11.*Executive Compensation.*

The information required by this item is incorporated herein by reference to the Company’s definitive proxy statement, which will be filed not later than 120 days after December 31, 2017.

Item 12.*Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

The information required by this item is incorporated herein by reference to the Company’s definitive proxy statement, which will be filed not later than 120 days after December 31, 2017.

Item 13.*Certain Relationships, Related Transactions and Director Independence.*

The information required by this item is incorporated herein by reference to the Company’s definitive proxy statement, which will be filed not later than 120 days after December 31, 2017.

Item 14.*Principal Accounting Fees and Services.*

The information required by this item is incorporated herein by reference to the Company’s definitive proxy statement, which will be filed not later than 120 days after December 31, 2017.

Table of Contents

Part IV

Item 15. ***Exhibits, Financial Statement Schedules.***

The following documents are filed as part of this report:

1. *Financial Statements:* See Item 8.
2. *Financial Statement Schedules:* None.

add3. *Index to Exhibits.* The following documents are included as exhibits to this Form 10-K. Exhibits incorporated by reference are duly noted as such.

Exhibit Number	Description
2.1	Debtors' Second Amended Joint Chapter 11 Plan of Reorganization (incorporated by reference to Exhibit A of the Order Confirming Debtors' Second Amended Joint Chapter 11 Plan of Reorganization, filed as Exhibit 99.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on March 16, 2017).
3.1	Articles of Reorganization of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Registration Statement on Form 8-A filed by Ultra Petroleum Corp. on April 12, 2017).
3.2	Amended and Restated By-Law No. 1 of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.2 to the Registration Statement on Form 8-A filed by Ultra Petroleum Corp. on April 12, 2017).
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017).
4.2	Indenture dated April 12, 2017 among Ultra Resources, Inc., Ultra Petroleum Corp., the subsidiary guarantors party thereto, and Wilmington Trust, National Association, as trustee. (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017.
10.1	Senior Secured Term Loan Agreement dated as of April 12, 2017, among Ultra Petroleum Corp. and UP Energy Corporation, as parent guarantor, Ultra Resources Inc., as borrower, Barclays Bank PLC, as administrative agent and the lenders and other parties party thereto. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017)
10.2	Credit Agreement dated as of April 12, 2017, among Ultra Petroleum Corp. and UP Energy Corporation, as parent guarantor, Ultra Resources, Inc., as borrower, Bank of Montreal, as administrative agent, and the lenders and other parties party thereto. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017)
10.3	First Amendment to Credit Agreement dated as of June 6, 2017, among Ultra Resources Inc., as borrower, Bank of Montreal, as administrative agent, and the lenders and other parties party thereto (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on June 12, 2017)
10.4	Guaranty and Collateral Agreement dated as of April 12, 2017, among Ultra Petroleum Corp. and the other parties signatory thereto, as grantors, and Bank of Montreal, as collateral agent. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on April 18, 2017)
10.5	Registration Rights Agreement dated as of April 12, 2017 by and among Ultra Petroleum Corp. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form 8-A filed by Ultra Petroleum Corp. on April 12, 2017).
10.6	Sale and Purchase Agreement dated October 18, 2013 between Axia Energy, LLC and UPL Three Rivers Holdings, LLC (incorporated by reference to Exhibit 1.1 of the Company's Report on Form 8-K filed on October 24, 2013).
10.7	Purchase and Sale Agreement dated August 13, 2014 between Ultra Petroleum Corp. and SWEPI LP (incorporated by reference from Exhibit 1.1 of the Company's Report on Form 8-K filed with the SEC on August 19, 2014).

Exhibit Number	Description
10.8	Ultra Petroleum Corp. 2017 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Registration Statement on Form S-8 filed by Ultra Petroleum Corp. on April 12, 2017).
10.9	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to the Registration Statement on Form S-8 filed by Ultra Petroleum Corp. on April 12, 2017).
10.10	First Amendment to Plan Support Agreement effective as of February 10, 2017, by and among Ultra Petroleum Corp. and the other Debtors, on the one hand, and certain holders of common stock in Ultra Petroleum Corp. and debt securities issued by Ultra Petroleum Corp., on the other hand (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Ultra Petroleum Corp. on February 15, 2017).
10.11	Employment Agreement of Michael D. Watford dated November 6, 2017 (incorporated by reference to Exhibit 10.8 of the Company's Quarterly Report on Form 10-Q filed with the SEC on November 9, 2017).
10.12	Employment Agreement of Garland R. Shaw dated November 6, 2017 (incorporated by reference to Exhibit 10.9 of the Company's Quarterly Report on Form 10-Q filed with the SEC on November 9, 2017).
10.13	Employment Agreement of Brad Johnson dated November 6, 2017 (incorporated by reference to Exhibit 10.10 of the Company's Quarterly Report on Form 10-Q filed with the SEC on November 9, 2017).
10.14	Employment Agreement of Kent Rogers dated November 6, 2017 (incorporated by reference to Exhibit 10.11 of the Company's Quarterly Report on Form 10-Q filed with the SEC on November 9, 2017).
10.15	Employment Agreement of Patrick Ash dated November 6, 2017 (incorporated by reference to Exhibit 10.12 of the Company's Quarterly Report on Form 10-Q filed with the SEC on November 9, 2017).
10.16	Employment Agreement of Garrett B. Smith dated November 6, 2017 (incorporated by reference to Exhibit 10.13 of the Company's Quarterly Report on Form 10-Q filed with the SEC on November 9, 2017).
*10.17	Separation Agreement among Ultra Petroleum Corp. and Michael D. Watford dated February 23, 2018.
*21.1	List of Subsidiaries of Ultra Petroleum Corp.
*23.2	Consent of Ernst & Young LLP.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Reserve Report Summary prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2017.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition

* Filed herewith.

SIGNATURES

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

ULTRA PETROLEUM CORP.

By: /s/ Michael D. Watford
Name: Michael D. Watford
Title: Chairman of the Board,
Chief Executive Officer, and President

Date: February 28, 2018

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	*Title*	*Date*
/s/ Michael D. Watford Michael D. Watford	Chairman of the Board, Chief Executive Officer, and President (principal executive officer)	February 28, 2018
/s/ Garland R. Shaw Garland R. Shaw	Senior Vice President and Chief Financial Officer (principal financial officer)	February 28, 2018
/s/ Maree K. Delgado Maree K. Delgado	Corporate Controller (principal accounting officer)	February 28, 2018
/s/ W. Charles Helton W. Charles Helton	Director	February 28, 2018
/s/ Stephen J. McDaniel Stephen J. McDaniel	Director	February 28, 2018
/s/ Roger A. Brown Roger A. Brown	Director	February 28, 2018
/s/ Michael J. Keeffe Michael J. Keeffe	Director	February 28, 2018
/s/ Neal P. Goldman Neal P. Goldman	Director	February 28, 2018
/s/ Alan J. Mintz Alan J. Mintz	Director	February 28, 2018

Exhibit 10.17

SEPARATION AND RELEASE AGREEMENT

THIS SEPARATION AND RELEASE AGREEMENT (the " Agreement") is made as of this 23rd day of February, 2018, by ULTRA PETROLEUM CORP., a Yukon corporation (the "Company"), and Michael D. Watford (the "Executive").

WHEREAS, the Executive serves as the Chairman of the Board of Directors of the Company (the "Board"), President and Chief Executive Officer of the Company, a member of the board of directors of applicable direct and indirect wholly-owned subsidiaries of the Company (collectively, the "Subsidiaries"), and President of applicable Subsidiaries;

WHEREAS, the Executive and the Company are signatories to an employment agreement effective November 6, 2017 (the "Employment Agreement"); and

WHEREAS, the Company and the Executive have mutually agreed to terminate their employment relationship under the terms and conditions set forth exclusively in this Agreement.

NOW, THEREFORE, in consideration of the mutual promises, representations and warranties set forth herein, and for other good and valuable consideration, the Executive and the Company agree as follows:

1. Cessation of Employment Relationship.

(a) The Executive's employment with the Company and its affiliates will cease, and the Executive will cease to serve as Chief Executive Officer and as an officer of the Company, effective as of the close of business on February 28, 2018 ("Termination Date"). Except as expressly provided in Section 2 of this Agreement, the Termination Date will be the termination date of Executive's employment for purposes of active participation in and coverage under all benefit plans and programs sponsored by or through the Company. The terms and conditions of the Employment Agreement will continue to apply until the Termination Date.

(b) Pursuant to Section 5(c)(iv) of the Employment Agreement, Executive's termination of employment on the Termination Date will constitute an automatic resignation of Executive, as of the Termination Date, from all positions he then holds as an employee, officer, director, manager or other service provider to the Company and each Subsidiary, including, for the avoidance of doubt, Executive's service on the Board.

2. Compensation.

(a) *Severance*. Subject to Section 2(d) herein, the termination of Executive's employment on the Termination Date in accordance with Section 1 of this Agreement will constitute a "termination without Cause" (as defined in the Employment Agreement), and, in full satisfaction of the Company's obligations under Sections 4 and 5 of the Employment Agreement, Executive will be entitled to the severance payments and benefits specified in the Employment Agreement, consisting of (i) payment of Executive's base salary through the Termination Date, (ii) payment of any unreimbursed Business Expenses (as defined in the Employment Agreement), including any automobile expenses covered by Section 4(d)(ii) of the Employment Agreement, incurred and paid by Executive up to and including the Termination Date, (iii) payment of any other vested compensation or benefits payable to Executive based on the express terms of the Company's compensation or benefit plans or programs and Executive's participation therein (clauses (i), (ii), and (iii) herein collectively the "Accrued Amounts", with such amounts or benefits paid or provided in accordance with Section 5(a)(x) of the Employment Agreement), (iv) cash severance paid in lump sum within thirty (30) days following the Termination Date in the amount of $3,762,950.41, which is equal to the sum of: (x) one hundred percent (100%) of Executive's base salary accrued and paid during the 24 months immediately preceding the Termination Date and (y) fifty percent (50%) of the aggregate cash incentive compensation paid to Executive in U.S. dollars, with respect to the 2016 and 2017 calendar years (the "Severance Payment"), (v) subject in all respects to Section 4(d)(iii) (provided any such modification is generally applicable to similarly-situated executives of the Company) and Section 13(f) of the Employment Agreement (except with respect to directors and officers liability insurance which shall be provided in all events), the Company shall make available to Executive, at the Company's cost and expense, continued participation in the Company's life insurance, disability insurance, directors and officers liability insurance, health and accident plans (including medical, dental and vision plans) and any other welfare, fringe or employee benefit plans Executive was participating in immediately prior to the Termination Date (collectively, the "Welfare Benefits") for a period beginning on the Termination Date and continuing for at least 24 months or, if earlier occurring, such time as Executive obtains other employment that provides Executive with benefits at least as favorable to Executive as the Welfare Benefits. Notwithstanding anything to the contrary set forth in this Section 2(a), any portion of the Severance Payment or Welfare Benefits that is considered nonqualified deferred compensation under Code Section 409A on the Termination Date shall not be made or provided until the date which is the earlier of (A) Monday, September 3rd, 2018, and (B) the date of the Executive's death, to the extent required under Code Section 409A, following which date, all payments and benefits so delayed shall be paid or reimbursed to the Executive (or upon his death, to his estate) in a lump sum, and any remaining payments and benefits due under this Agreement shall be paid or provided in accordance with the normal payment dates specified for them herein.

(b) *Equity Acceleration*. Subject to Section 2(d) herein, upon the Release Effective Date, all outstanding and unvested awards granted pursuant to that certain Restricted Stock Unit Agreement by and between Executive and the Company dated April 12, 2017 pursuant to the Ultra Petroleum 2017 Stock Incentive Plan (the "Emergence Agreement") held by Executive as of the Termination Date (i.e., 1,226,102 shares) will automatically, and without any action on the part of the Executive, become vested and delivered to Executive (the "Equity Acceleration"). Company agrees that such shares will be delivered net of the shares withheld to pay the withholding taxes due upon delivery of such shares. Executive and the Company acknowledge and agree that as of the Termination Date, Executive has no outstanding Equity Incentives other than those set forth in the Emergence Agreement. Notwithstanding anything to the contrary set forth in this Section 2(b), if the delivery of any portion of the Equity Acceleration is considered nonqualified deferred compensation under Code Section 409A on the Termination Date, delivery of shares of common stock pursuant to such portion of the Equity Acceleration shall not be made or provided until the date which is the earlier of (A) the expiration of the six (6)-month period measured from the Termination Date, and

(B) the date of the Executive's death, to the extent required under Code Section 409A; provided the number of shares shall be equitably adjusted to take into account any stock splits or similar corporate transactions. The Company acknowledges that following the Termination Date, there are no Company-imposed restrictions on Executive's ability to transfer or sell any stock he owns (or will own upon delivery of the shares in accordance with this Section 2(b)) in the Company.

(c) *Title Transfer*. No later than thirty (30) days following the Termination Date, the Company will transfer to Executive the title ownership of the Automobile (as defined in the Employment Agreement), free and clear of any liens or encumbrances thereon.

(d) *Release Requirement*. Pursuant to Section 5(e) of the Employment Agreement, in order to be entitled to receive the Severance Payment, Welfare Benefits and Equity Acceleration, the Executive must execute and return to the Company the general waiver and release attached hereto as **Exhibit A** no earlier than the day following the Termination Date and no later than the twenty-first (21st) day following the Termination Date and Executive must not revoke the release during the period of time the release is subject to revocation as provided therein (the date on which the release becomes effective and is no longer subject to revocation, the "Release Effective Date"). Upon the Release Effective Date, the Company agrees to promptly execute Executive's executed and irrevocable waiver and release in the form attached hereto as **Exhibit A** and return an executed version to Executive.

(e) *No Other Compensation or Benefits*. Executive acknowledges that, except as expressly provided in this Agreement or as otherwise required by applicable law, Executive will not receive any additional compensation, severance or other benefits as an employee of any kind following the Termination Date; provided that nothing herein shall affect any rights Executive has to be indemnified for third party claims or to be covered under any applicable directors' and officers' insurance policies, including any tail directors' and officers' liability insurance policies he was covered pursuant to immediately prior to the Termination Date.

3. Restrictive Covenants; Survival. Executive hereby (a) reaffirms the rights and obligations contained within Section 7 (Confidential Information), Section 8 (Inventions), Section 9 (Cooperation and Assistance), Section 11 (Non-Solicitation) and Section 12 (Non-Disparagement), in each case, of the Employment Agreement (collectively, the "Continuing Obligations"), (b) understands, acknowledges and agrees that the Continuing Obligations will survive Executive's termination of employment with the Company and remain in full force and effect in accordance with all of the terms and conditions thereof, and (c) represents and warrants that Executive has not violated any of the Continuing Obligations as of the date hereof. The Company confirms that other than the Continuing Obligations there are no Company-imposed restrictions on Executive's activities following the Termination Date.

4. Governing Law. This Agreement, the rights and obligations of the parties hereto, and any claims or disputes relating thereto, shall be governed by and construed in accordance with the laws of the State of Texas (but not including any choice of law rule thereof that would cause the laws of another jurisdiction to apply), and any dispute in relation to this Agreement shall be subject to the exclusive jurisdiction of the state and federal courts located in Harris

County, Texas. Executive and the Company irrevocably waive any objections which Executive or the Company may have to the laying of the venue of any suit, action or proceeding arising out of or relating to this Agreement or Executive's engagement by, or provision of services to, any Company affiliate in any court in the State of Texas, and shall further irrevocably waive any claim that any such suit, action or proceeding brought in any such court has been brought in any inconvenient forum. Executive and the Company shall waive any right Executive or the Company may have to trial by jury in respect of any litigation based on, arising out of, under or in connection with this Agreement or Executive's engagement by, or provision of services to, any Company affiliate. The Company agrees that Section 13(e)(iii) of the Employment Agreement shall continue to apply in accordance with its terms.

5. Tax Matters.

(a) The Company may withhold from any and all amounts payable under this Agreement such federal, state, local or foreign taxes as may be required to be withheld pursuant to any applicable law or regulation.

(b) The intent of the parties is that payments and benefits contemplated under this Agreement that are subject to Internal Revenue Code Section 409A and the regulations and guidance promulgated thereunder comply with the requirements thereof, and accordingly, to the maximum extent permitted, this Agreement will be interpreted to be in compliance therewith. Executive and the Company hereby agree that Executive's termination of employment on the Termination Date will constitute a "separation from service" within the meaning of Internal Revenue Code Section 409A. To the extent this Agreement provides for reimbursements of expenses incurred by the Executive or in-kind benefits the provision of which are not exempt from the requirements of Section 409A, the following terms apply with respect to such reimbursements or benefits: (i) the reimbursement of expenses or provision of in-kind benefits will be made or provided only during the period of time specifically provided herein; (ii) the amount of expenses eligible for reimbursement, or in-kind benefits provided, during a calendar year will not affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other calendar year; (iii) all reimbursements will be made no later than the last day of the calendar year immediately following the calendar year in which the expense was incurred; and (iv) the right to reimbursement or the in-kind benefit will not be subject to liquidation or exchange for another benefit. Each payment made under this Agreement shall be treated as a separate payment and the right to a series of installment payments under this Agreement is to be treated as a right to a series of separate payments. In addition, the provisions of the Employment Agreement relating to Internal Revenue Code Section 409A, including Section 5(a)(x) and Schedule 2, are incorporated into this Agreement with full force and effect.

6. Entire Agreement. Except as otherwise expressly provided herein, this Agreement (including **Exhibit A** attached hereto) constitutes the entire agreement between Executive and the Company with respect to the subject matter hereof and supersedes any and all prior agreements or understandings between Executive and the Company with respect to the subject matter hereof, whether written or oral. This Agreement will bind the heirs, personal representatives, successors and assigns of Executive and the Company and inure to the benefit of

Executive, the Company, and Executive's and its respective heirs, successors and assigns, provided that neither Executive nor the Company may assign rights or obligations hereunder without the express written consent of the other, except that the Company may assign its rights and obligations hereunder to a successor in interest to all or substantially all of the Company's business, whether by way of merger, acquisition, consolidation or otherwise. This Agreement may be amended or modified only by a written instrument executed by Executive and the Company. If Executive should die while any payment or benefit is due to him hereunder, such payment or benefit shall be paid or provided to his estate.

7. Counterparts & Signatures. This Agreement may be executed in counterparts, each of which shall be deemed an original, and together any counterparts shall constitute one and the same instrument. Additionally, the parties agree that electronic reproductions of signatures (i.e., scanned PDF versions of original signatures, facsimile transmissions, and the like) shall be treated as original signatures for purposes of execution of this Agreement.

[Remainder of page intentionally left blank. Signature page follows.]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

ULTRA PETROLEUM CORP.

By: *__/s/ Wm. Charles Helton__*
Name: Dr. Wm. Charles Helton
Title: Lead Independent Director and Chairman of the Compensation Committee

Date: 23 February 2018

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

Accepted and Agreed:

/s/ Michael D. Watford
Name: Michael D. Watford
Date: 2/23/2018

EXHIBIT A

You should consult with an attorney before signing this release of claims.

Release Agreement

1. In consideration of the payments and benefits (the "Severance Benefits") set forth in Section 2(a) and Section 2(b) of the Separation and Release Agreement dated as of February 23, 2018 by and between by and between Michael D. Watford (the "Executive") and ULTRA PETROLEUM CORP. (the "Company") (the "Separation Agreement") (each of the Executive and the Company, a "Party" and collectively, the "Parties"), the sufficiency of which the Executive acknowledges, the Executive, with the intention of binding himself and his heirs, executors, administrators and assigns, does hereby release, remise, acquit and forever discharge the Company and each of its subsidiaries and affiliates (the "Company Affiliated Group"), their present and former officers, directors, executives, shareholders, agents, attorneys, employees and employee benefit plans (and the fiduciaries thereof), and the successors, predecessors and assigns of each of the foregoing (collectively, the "Company Released Parties"), of and from any and all claims, actions, causes of action, complaints, charges, demands, rights, damages, debts, sums of money, accounts, financial obligations, suits, expenses, attorneys' fees and liabilities of whatever kind or nature in law, equity or otherwise, whether accrued, absolute, contingent, unliquidated or otherwise and whether now known or unknown, suspected or unsuspected, which the Executive, individually or as a member of a class, now has, owns or holds, or has at any time heretofore had, owned or held, arising on or prior to the date hereof, against any Company Released Party, including without limitation any claim that arises out of, or relates to, (i) the Employment Agreement, effective November 6, 2017 by and between Executive and the Company (the "Employment Agreement"), the Restricted Stock Unit Agreement, dated April 12, 2017, by and between the Executive and the Company, the Executive's employment with the Company or any of its subsidiaries and affiliates, or any termination of such employment, (ii) for severance or vacation benefits, unpaid wages, salary or incentive payments, (iii) breach of contract, wrongful discharge, impairment of economic opportunity, defamation, intentional infliction of emotional harm or other tort, (iv) any violation of applicable state and local labor and employment laws (including, without limitation, all laws concerning unlawful and unfair labor and employment practices) and/or (v) for employment discrimination under any applicable federal, state or local statute, provision, order or regulation, and including, without limitation, any claim under Title VII of the Civil Rights Act of 1964 ("Title VII"), the Civil Rights Act of 1988, the Fair Labor Standards Act, the Americans with Disabilities Act ("ADA"), the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), the Age Discrimination in Employment Act ("ADEA"), the Texas Commission on Human Rights Act, TX Labor Code § 21.001 et seq., the Texas Payday Law, TX Labor Code § 61.001 et seq., the Texas Minimum Wage Act, TX Labor Code § 62.001 et seq., and the Texas Communicable Disease Act, TX Health and Safety Code § 81.101 et seq., all as amended, and any similar or analogous state statute, excepting only:

A. rights of the Executive to the Accrued Amounts, the Severance Payment, the Welfare Benefits, the Equity Acceleration (as all such terms are defined in the

Separation Agreement), the payment of the 2017 bonus and all other rights of the Executive as set forth in the Separation Agreement;

B. the right of the Executive to receive COBRA continuation coverage in accordance with applicable law;

C. claims for benefits under any health, disability, retirement, deferred compensation, life insurance or other similar employee benefit plan (within the meaning of Section 3(3) of ERISA) of the Company Affiliated Group; and

D. rights to indemnification the Executive has or may have under an agreement with any member of the Company Affiliated Group, the by-laws or certificate of incorporation of any member of the Company Affiliated Group or as an insured under any director's and officer's liability insurance policy now or previously in force, including any tail policy.

In addition, nothing in this Release prevents Executive from filing, cooperating with, or participating in any proceeding before the Equal Employment Opportunity Commission, the Securities and Exchange Commission, or the Department of Labor, except that Executive hereby waives his right to any monetary benefits in connection with any such claim, charge or proceeding. Nothing contained in this Agreement shall be construed to prohibit the Executive from reporting possible violations of federal or state law or regulation to any governmental agency or regulatory body or making other disclosures that are protected under any whistleblower provisions of federal or state law or regulation, or from filing a charge with or participating in any investigation or proceeding conducted by any governmental agency or regulatory body. For the avoidance of doubt, Executive is not releasing claims with respect to any rights he had upon the Company's emergence from bankruptcy with respect to his rights to be indemnified or covered under any directors' and officers' liability insurance policies, including any tail policies, or to be released from certain claims. For the avoidance of doubt by executing this Release, the Executive is not forfeiting his common stock ownership in the Company.

2. The Company confirms that as of the date it signs this Release that the board of directors of the Company is not aware of any claim any member of the Company Affiliated Group has or may have against the Executive.

3. Pursuant to 18 U.S.C. § 1833(b), an individual may not be held criminally or civilly liable under any federal or state trade secret law for the disclosure of a trade secret that: (i) is made (A) in confidence to a federal, state or local government official, either directly or indirectly, or to an attorney, and (B) solely for the purpose of reporting or investigating a suspected violation of law or (ii) is made in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal. Additionally, an individual who files a lawsuit for retaliation by an employer for reporting a suspected violation of law may disclose a trade secret to the attorney of the individual and use the trade secret information in the court proceeding, if the individual: (A) files any document containing the trade secret under seal and (B) does not disclose the trade secret except pursuant to court order.

4. The Executive acknowledges and agrees that this Release is not to be construed in any way as an admission of any liability whatsoever by any Company Released Party, any such liability being expressly denied. The Company acknowledges and agrees that this Release is not to be construed in any way as an admission of any liability whatsoever by the Executive, any such liability being expressly denied.

5. This Release applies to any relief no matter how called, including, without limitation, wages, back pay, front pay, compensatory damages, liquidated damages, punitive damages, damages for pain or suffering, costs, and attorneys' fees and expenses but does not apply to the claims not released by the Executive in Section 1 above.

6. The Executive specifically acknowledges that his acceptance of the terms of this Release is, among other things, a specific waiver of his rights, claims and causes of action under Title VII, ADEA, ADA and any state or local law or regulation in respect of discrimination of any kind; provided, however, that nothing herein shall be deemed, nor does anything contained herein purport, to be a waiver of any right or claim or cause of action which by law the Executive is not permitted to waive.

7. As to rights, claims and causes of action arising under ADEA, the Executive acknowledges that he been given a period of twenty-one (21) days to consider whether to execute this Release. If the Executive accepts the terms hereof and executes this Release, he may thereafter, for a period of seven (7) days following (and not including) the date of execution, revoke this Release as it relates to the release of claims arising under ADEA. If no such revocation occurs, this Release shall become irrevocable in its entirety, and binding and enforceable against the Executive, on the day next following the day on which the foregoing seven-day period has elapsed. If such a revocation occurs, the Separation Agreement shall terminate and be of no further force and effect, and the Executive shall irrevocably forfeit any right to payment of the Severance Payment, the Welfare Benefits, and the Equity Acceleration (other than $1,000 as consideration for the rights, claims and causes of actions that continue to be waived hereunder and his rights to be indemnified and covered under any applicable directors' and officers' liability insurance policies) or any other cash severance, benefits continuation or other post-termination benefits pursuant to the Employment Agreement (other than rights to the Accrued Amounts (as defined in the Separation Agreement) and any rights to be indemnified or covered under any applicable directors' and officers' liability insurance policies), but the remainder of the Employment Agreement shall continue in full force.

8. Other than as to rights, claims and causes of action arising under ADEA, this Release shall be immediately effective upon execution by the Executive.

9. The Executive acknowledges and agrees that he has not, with respect to any transaction or state of facts existing prior to the date hereof, filed any complaints, charges or lawsuits against any Company Released Party with any governmental agency, court or tribunal.

10. The Executive acknowledges that he has been advised to seek, and has had the opportunity to seek, the advice and assistance of an attorney with regard to this Release, and has been given a sufficient period within which to consider this Release.

11. The Executive acknowledges that this Release relates only to claims that exist as of the date of this Release.

12. The Executive acknowledges that the Severance Payment, the Welfare Benefits, and the Equity Acceleration he is receiving in connection with this Release and his obligations under this Release are in addition to anything of value to which the Executive is entitled from the Company.

13. Each provision hereof is severable from this Release, and if one or more provisions hereof are declared invalid, the remaining provisions shall nevertheless remain in full force and effect. If any provision of this Release is so broad, in scope, or duration or otherwise, as to be unenforceable, such provision shall be interpreted to be only so broad as is enforceable.

14. This Release constitutes the complete agreement of the Parties in respect of the subject matter hereof and shall supersede all prior agreements between the Parties in respect of the subject matter hereof except to the extent set forth herein. For the avoidance of doubt, this Release does not supersede the Separation Agreement.

15. The failure to enforce at any time any of the provisions of this Release or to require at any time performance by another party of any of the provisions hereof shall in no way be construed to be a waiver of such provisions or to affect the validity of this Release, or any part hereof, or the right of any party thereafter to enforce each and every such provision in accordance with the terms of this Release.

16. This Release may be executed in several counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument. Signatures delivered by facsimile shall be deemed effective for all purposes.

17. This Release shall be binding upon any and all successors and assigns of the Executive and the Company.

18. Except for issues or matters as to which federal law is applicable, this Release shall be governed by and construed and enforced in accordance with the laws of the State of Delaware without giving effect to the conflicts of law principles thereof.

IN WITNESS WHEREOF, the Company has executed this Release as of the date written below.

ULTRA PETROLEUM CORP.

By: ___________________________
Name: Dr. Wm. Charles Helton
Title: Lead Independent Director and Chairman of the Compensation Committee

Date: February 28, 2018

IN WITNESS WHEREOF, the Executive has executed this Release as of the date written below.

Accepted and Agreed:

____
Name: Michael D. Watford
Date:

Exhibit 21.1

LIST OF SUBSIDIARIES OF ULTRA PETROLEUM CORP.

Entity	Jurisdiction of Organization
UP Energy Corporation	Delaware
Ultra Resources, Inc.	Delaware
Ultra Wyoming, LLC	Delaware
UPL Pinedale, LLC	Delaware
UPL Three Rivers Holdings, LLC	Delaware
Ultra Wyoming LGS, LLC	Delaware
Keystone Gas Gathering, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

Netherland, Sewell & Associates, Inc. has issued a report, as of December 31, 2017, of the “Estimates of Reserves and Future Revenue to the Ultra Petroleum Corp. Interest in Certain Oil and Gas Properties located in Utah and Wyoming as of December 31, 2017” for Ultra Petroleum Corp. Netherland, Sewell & Associates, Inc. consents to the reference in Form 10-K to Netherland, Sewell & Associates, Inc.’s reserves report dated February 16, 2018, and to the incorporation by reference of our Firm’s name and report into Ultra’s previously filed Registration Statements on Form S-1 and Form S-1A (File No. 333-217481) and Form S-8 (File No. 333-217268).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C. H. (Scott Rees) III, P.E.
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 28, 2018

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-217268) pertaining to the Ultra Petroleum Corp. 2017 Stock Incentive Plan, and

(2) Registration Statement (Form S-1 No. 333-217481) pertaining to the registration of Common Stock issued pursuant to the Plan of Reorganization;

of our reports dated February 28, 2018, with respect to the consolidated financial statements of Ultra Petroleum Corp. and subsidiaries (which report expresses an unqualified opinion) and the effectiveness of internal control over financial reporting of Ultra Petroleum Corp. and subsidiaries included in this Annual Report (Form 10-K) of Ultra Petroleum Corp. for the year ended December 31, 2017.

/s/ Ernst & Young LLP
Houston, Texas
February 28, 2018

Exhibit 31.1

CERTIFICATION

I, Michael D. Watford, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ultra Petroleum Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Michael D. Watford

Michael D. Watford,
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Date: February 28, 2018

Exhibit 31.2

CERTIFICATION

I, Garland R. Shaw, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ultra Petroleum Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ Garland R. Shaw

Garland R. Shaw,
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 28, 2018

Exhibit 32.1

SECTION 906 CERTIFICATION PURSUANT OF PRINCIPAL EXECUTIVE OFFICER
ULTRA PETROLEUM CORP.

In connection with the Annual Report of Ultra Petroleum Corp. (the ***"Company"***) on Form 10-K for the fiscal year ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the ***"Report"***), I, Michael D. Watford, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael D. Watford
Michael D. Watford,
Chairman, President and Chief Executive Officer
(Principal Executive Officer)

Dated: February 28, 2018

This certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

Exhibit 32.2

SECTION 906 CERTIFICATION PURSUANT OF PRINCIPAL FINANCIAL OFFICER
ULTRA PETROLEUM CORP.

In connection with the Annual Report of Ultra Petroleum Corp. (the ***"Company"***) on Form 10-K for the fiscal year ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (the ***"Report"***), I, Garland R. Shaw, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Garland R. Shaw
Garland R. Shaw,
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Dated: February 28, 2018

This certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. This certification will not be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

February 16, 2018

Mr. Jason Gaines
Ultra Petroleum Corp.
116 Inverness Drive East, Suite 400
Englewood, Colorado 80112

Dear Mr. Gaines:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Ultra Petroleum Corp. (Ultra) interest in certain oil and gas properties located in Utah and Wyoming. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Ultra. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Ultra's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Ultra interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	21,343.5	71.5	2,231,933.8	3,532,832.0	2,123,987.0
Proved Developed Non-Producing	309.0	0.0	29,355.4	49,973.6	27,669.4
Proved Undeveloped	5,465.6	0.0	694,703.6	794,538.1	232,671.2
Total Proved	27,118.1	71.5	2,955,992.8	4,377,343.7	2,384,327.6

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that may exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Ultra's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Ultra's share of production taxes, ad valorem taxes, capital costs, abandonment costs, operating expenses, and payments to net profit interests but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average spot price is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average spot price is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $48.05 per barrel of oil, $26.85 per barrel of NGL, and $2.592 per MCF of gas. Average index prices along with the average realized prices for each area are shown in the following table:

	Oil/NGL				Gas		
			Average Realized Prices ($/Barrel)				
Area	Pricing Index	Average Spot Price ($/Barrel)	Oil	NGL	Pricing Index	Average Spot Price ($/MMBTU)	Average Realized Price ($/MCF)
Utah	West Texas Intermediate	51.34	46.40	26.85	Kern River (Opal plant)	2.710	2.279
Wyoming	West Texas Intermediate	51.34	48.34	N/A	Kern River (Opal plant)	2.710	2.592

Operating costs used in this report are based on operating expense records of Ultra. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Ultra are included to the extent that they are covered under joint operating agreements for the operated properties. The fees associated with transportation and processing contracts for the properties are included as a separate economic projection in each proved reserves category; our estimates of future revenue do not account for any potential deficiency payments related to gas or liquids volumes transportation and processing contracts that are currently in place. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Ultra and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Ultra's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Ultra interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Ultra receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Ultra, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Ultra, other interest owners, various operators of the properties, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Sean A. Martin, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2014 and has over 7 years of prior industry experience. Philip R. Hodgson, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ C.H. (Scott) Rees III

By:

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

NETHERLAND, SEWELL & ASSOCIATES, INC.

By:	/s/ Sean A. Martin	By:	s/ Philip R. Hodgson
	Sean A. Martin, P.E. 125354		Philip R. Hodgson, P.G. 1314
	Petroleum Engineer		Vice President
Date Signed:	February 16, 2018	Date Signed:	February 16, 2018

SAM:CDC

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is 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.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity

does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* 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.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a.Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)

b.Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a.Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b.Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c.Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.

d.Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e.Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f.Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and 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.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.